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August 19, 2011

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Utilities[1] ("FEU") 2012 and 2013 Revenue Requirements and Natural Gas Rates Application

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On May 4, 2011, the FEU filed the Application as referenced above. In accordance with Commission Order No. G-129-11 issuing the amended Regulatory Timetable, the FEU respectfully submit the attached response to BCUC IR No. 2.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

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[1] Comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy (Vancouver Island) Inc. ("FEVI")

1.0 Reference: Under-spending on EEC Programs

Exhibit B-9, BCUC IR 1.3.1

On page 15 of the "TGI-TGVI Energy Efficiency and Conservation Programs" application filed with the Commission on May 28, 2008, FEU made the following submission:

"In the event the Terasen Utilities spend more or less than the approved amount for a particular year, the over or under-spend shall be factored into the EEC spending in the following year, but the total amount expended by the Companies on EEC activity between approval and 2010 would not exceed $56.6 million, unless otherwise approved by the Commission. The Companies will continue to assess over the course of the Program Period whether customers would benefit from additional EEC spending over and above the funding sought in this Application, and will bring forward any further applications as appropriate."

1.1 In the statement above, does FEU believe that if FEU under spends on EEC, those under spent amounts shall be considered in the following year?

Response:

This response also addresses BCUC IR 2.1.2.

The 2008 EEC Application proposed a funding envelope that covered a three-year period from 2008 to 2010. Within this three-year funding envelope period, the FEU intended to be able to carry forward any overspent or underspent amounts from one year to the next so long as the total approved funding amount over the three years was not exceeded. However, the FEU do not believe that underspent EEC amounts are carried over to the following year if the year is outside the approved funding envelope period.

The 2010-2011 RRAs for both FEI and FEVI laid out incremental EEC funding for 2010 and 2011, separating out the funding approved for each year, rather than approving an overall funding envelope over a multi-year period. This approach was outlined in the Negotiated Settlement Agreements pertaining to the 2010-2011 RRAs and approved by BCUC Order No. G-140-09 for FEVI and Order No. G-141-09 for FEI.

Consistent with the previous RRA, in this RRA, the FEU have proposed an annual funding envelope rather than the three-year funding envelope as proposed in the 2008 EEC Application. As can be seen on page 4 of Appendix K-1 to the Application (Exhibit B-1), the FEU are proposing maximum EEC expenditures of $74.5 million per year, which the FEU would not exceed in any given year. Furthermore, the FEU are not proposing that any underspent amounts be carried forward into the following year.

In the 2008 EEC Application and the revenue requirement applications the FEU have not advocated the allocation of underspent amounts to subsequent funding envelope periods.

1.2 Does this excerpt mean if FEU under-spends on EEC, the Utility can spend these amounts in the future years thus not losing out on spending ability?

Response:

Please see the response to BCUC IR 2.1.1.

1.3 Does this excerpt mean that if FEU under-spends on EEC, that customers will still be charged rates assuming the full amount of EEC spending occurred, however, the difference between actual and forecast amortization on the deferral account will be lost?

Response:

No, the difference between actual and forecast amortization on the EEC deferral account is not lost, rather it is more appropriately classified as a timing difference. With each successive revenue requirement and reset of delivery rates, FEU re-forecasts the opening deferral account balance based on previous actual EEC costs and, as a result, the amortization of the deferral account is re-forecast to recover the previous actual EEC costs. Thus, over the life of the deferral account, only the actual EEC costs incurred are collected from customers.

1.4 Is FEU willing to reduce the carrying value of the EEC deferral account at the end of F2011 by the amount that shareholders benefited forecasted to be ($305K +$ 667K) due to FEI under-spending on EEC?

Response:

The FEU are not willing to reduce the carrying value of the EEC deferral account at the end of 2011 by the equity return amounts, as provided in BCUC IR 1.3.1, associated with the underspend on EEC. As was explained in the response to BCUC IR 1.3.1, isolation of a single component of the rate base or cost of service does not provide a comprehensive perspective of the performance of the FEU or the total quantitative and qualitative benefits provided to our customers in a given year.

BCUC IR 1.3.1 also states that the actual return on equity for FEI was lower than the approved amount in 2010. This was due to multiple factors, with the variance in the EEC deferral account being only one component of the total variance in return on equity. The FEU believe it is not appropriate to consider retroactively this single component of rate base in the setting of its future revenue requirements.

2.0 Reference: Rate Sensitivity

Exhibit B-9, BCUC IR 1.4.1

2.1 Please complete BCUC IR 1.4.1 for FEI, FEVI, FEW and FEI-Fort Nelson for Total Rates (not delivery rates) for an average residential, commercial and industrial customer? Use the most recent cost of gas as the base amount for your calculations.

Response:

As discussed in response to BCUC IR 1.4.1, changes to the price of natural gas and the BC Hydro RIB 2 rate do not impact the rate proposals contained in this Application for Mainland, Whistler and Fort Nelson. The cost of gas for Mainland, Whistler and Fort Nelson is set through the quarterly gas cost filing process. The cost of gas for these three utilities does not impact the determination of the revenue deficiency or surplus in this Application because the revenue at existing rates includes commodity and midstream revenue that fully offsets the forecast cost of gas.[1] Also discussed in BCUC IR 1.4.1, the soft-cap mechanism is no longer used to set natural gas rates on Vancouver Island. Therefore, although changes to the equivalent BC Hydro RIB 2 rate will impact the competitiveness of Vancouver Island, changes to the BC Hydro RIB 2 rate do not directly impact the revenue deficiency or surplus of Vancouver Island.
Therefore, the delivery rate component of the burner tip rate is not impacted in all scenarios for Mainland, Whistler and Fort Nelson and the FEU have excluded the RIB 2 rate changes from all of the tables. The analysis assumes the following:

- Existing approved rates effective July 1, 2011 are used as the comparison point to determine the approximate burner rate increase (expressed as a percent) under the various scenarios

- In order to more appropriately match the gas cost recovery rate impacts under the various scenarios requested to the delivery rates, the gas costs were reset effective January 1, 2012 and January 1, 2013, to fully recover the forecast costs for the respective 12-month prospective periods, regardless of whether the rate change fell within the normal threshold range.

- Revelstoke propane costs are excluded from this analysis

- For Vancouver Island, the rate increase is based on the total deficiency or surplus for each scenario over total revenue at existing 2011 rates, and does not reflect any draw down of the RSDA balance to offset the rate increase

[1] Excluding any minor impacts on working capital that may result

The tables below indicate that Mainland customers experience the largest percent burner tip rate increase under the various commodity scenarios. This is expected because the burner tip rate for a Mainland customer is lower than the burner tip rate for customers in Whistler and Vancouver Island. All else equal, a similar dollar change in the rate amongst the utilities will result in a larger percent impact to Mainland because the basis for comparison is lower. Conversely, Vancouver Island will show the smallest percent increase as compared to the other utilities because the burner tip rate is higher than the other utilities. For example, the approximate existing burner tip rate for a Lower Mainland Residential customer is approximately $10.60/GJ as compared to approximately $16.30 for a Residential customer in Whistler and $16.50 for Residential customer in Vancouver Island. Therefore, if all utilities experienced a $3.00/GJ increase in their burner tip rates (similar to the $8/GJ scenario below), it would result in a 28.3% increase in Mainland, an 18.4% increase in Whistler and an 18.2% increase in Vancouver Island.

The approximate percent increase in the burner tip rate for Residential, Commercial and Industrial customers, under each scenario, is provided for Mainland, Whistler, Fort Nelson and Vancouver Island in Tables 1 through 5 below.

Table 1: Mainland[2]

Mainland			2012	2013	Total
Rate increase if natural gas prices =$8/GJ	Residential	Effective Burner Tip Rate	27%	7%	34%
	Small Commercial	Effective Burner Tip Rate	30%	7%	37%
	Large Commercial	Effective Burner Tip Rate	34%	8%	42%
	Industrial	Effective Burner Tip Rate	36%	9%	45%
Rate increase if natural gas prices =$10/GJ	Residential	Effective Burner Tip Rate	47%	5%	52%
	Small Commercial	Effective Burner Tip Rate	52%	5%	57%
	Large Commercial	Effective Burner Tip Rate	58%	6%	64%
	Industrial	Effective Burner Tip Rate	62%	7%	69%
Rate increase if natural gas prices =$14/GJ	Residential	Effective Burner Tip Rate	85%	2%	87%
	Small Commercial	Effective Burner Tip Rate	95%	2%	97%
	Large Commercial	Effective Burner Tip Rate	107%	3%	110%
	Industrial	Effective Burner Tip Rate	115%	3%	118%

2 Residential is Lower Mainland Rate Schedule 1, Small Commercial is Lower Mainland Rate Schedule 2, Large Commercial is Lower Mainland Rate 3 and Industrial is Lower Mainland Rate Schedule 5

Table 2: Whistler

Whistler			2012	2013	Total
Rate increase if natural gas prices =$8/GJ	All Customers	Effective Burner Tip Rate	15%	4%	19%
Rate increase if natural gas prices =$10/GJ	All Customers	Effective Burner Tip Rate	27%	3%	30%
Rate increase if natural gas prices =$14/GJ	All Customers	Effective Burner Tip Rate	51%	1%	52%

Table 3: Fort Nelson[3]

Fort Nelson			2012	2013	Total
Rate increase if natural gas prices =$8/GJ	Residential	Effective Burner Tip Rate	23%	15%	38%
	Small Commercial	Effective Burner Tip Rate	21%	15%	36%
	Large Commercial	Effective Burner Tip Rate	23%	15%	38%
Rate increase if natural gas prices =$10/GJ	Residential	Effective Burner Tip Rate	35%	28%	63%
	Small Commercial	Effective Burner Tip Rate	33%	26%	59%
	Large Commercial	Effective Burner Tip Rate	35%	28%	63%
Rate increase if natural gas prices =$14/GJ	Residential	Effective Burner Tip Rate	61%	52%	113%
	Small Commercial	Effective Burner Tip Rate	57%	50%	107%
	Large Commercial	Effective Burner Tip Rate	61%	52%	113%

[3] Residential customer is Rate Schedule 1, Small Commercial is Rate Schedule 2.1 and Large Commercial is Rate Schedule 2.2

Please see the table below which has been updated to reflect the approximate rate increase that would be required for Vancouver Island under each scenario. The analysis assumes the following:

Table 4: Vancouver Island (without RSDA)

Vancouver Island	2012	2013	Total
Rate increase if natural gas prices =$8/GJ	14%	8%	22%
Rate increase if natural gas prices =$10/GJ	22%	8%	30%
Rate increase if natural gas prices =$14/GJ	36%	9%	45%

Table 5 below provides the rate increases after applying the RSDA balance to offset the rate increases in Table 4.

Table 5: Vancouver Island (with RSDA)

Vancouver Island	2012	2013	Total
Rate increase if natural gas prices =$8/GJ	0%	1%	1%
Rate increase if natural gas prices =$10/GJ	0%	16%	16%
Rate increase if natural gas prices =$14/GJ	1%	44%	45%

2.2 In FortisBC FortisBC Inc 2012-2013 Revenue Requirements and Review of ISP filed with the Commission on June 30, 2011, that utility describes the effects of the PBR and the ongoing benefits customers receive from the cost reductions received during the PBR period. Specifically, section 1.0 and 1.7 and 1.10, of that application discuss the cost achievements during the PBR and compare current costs to these last PBR period amounts. As FEU has been outside of a PBR period for a number of years, please provide some analysis to demonstrate that cost reductions achieved during the PBR have not been lost. Include a discussion and analysis comparing areas such as, capital additions and maintenance for 2010, 2011, 2012 and 2013 to actual costs in the last PBR period and explain how variances relate to potential cost savings lost after the PBR period has ended.

Response:

FEI has been out of PBR for almost two years, starting in 2010. In its 2010-2011 RRA, FEI also described the benefits of the PBR, including final earnings sharing for customers of $67.5 million over the six-year term. The savings that were achieved in the PBR period are generally sustainable in a static environment. However, over time, changes in external requirements (for example changes to codes and regulations, customer and stakeholder expectations, and energy policy) result in increasing expenditures to meet those requirements. As was described in the 2010-2011 RRA, a number of the efficiencies that were realized can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred.

During the PBR period, the savings were achieved through a number of means, including the Utilities Strategy Project, deferring activities and related costs where safe and prudent to do so, management of the meter to cash process resulting in the lowering of bad debts, centralized asset management in Distribution services, and department reorganization and streamlining. FEI continues to see lower costs in many areas from these initiatives which are permanent in nature but the savings have been offset by changing priorities and new initiatives in many other areas, therefore capital expenditures and O&M in 2012 and 2013 are both higher than during the PBR period.

To determine if permanent savings continue to be realized, FEI has calculated what the Lower Mainland residential delivery rate would be in 2012 and 2013 if the 2003 delivery rate were increased by inflation. The proposed delivery rates for 2012 and 2013 are within two percent of what they would be under this pure inflation scenario. Based on this, and the fact that there have been requirements to increase expenditures to meet new requirements and that changes in accounting standards (which led to among other things the expensing of training and project development costs, etc.) and depreciation rates have served to increase rates, FEI concludes that it has been able to retain some of the cost reductions that were achieved during the PBR period.

3.0 Reference: Olympic Cauldron

Exhibit B-9, BCUC IR 1.5.12

3.1 Please explain which asset class the Cauldron has been allocated to within the Uniform System of Accounts?

<u>Response:</u>

This response addresses BCUC IRs 2.3.1 through 2.3.7.

The Cauldron has been recorded in Asset Class 48600 – Tools & Equipment with an annual depreciation rate of 5 percent.

As discussed in response to BCUC IR 1.5.12, since the Cauldron was not forecast in the capital additions or operating expenses during any of the years 2009 through 2011, for those years 100% of the cost was borne by the shareholder. For the years 2012 forward, the remaining undepreciated capital cost of the Cauldron has been included in rate base and is being recovered from customers. At a current revenue requirements impact of approximately $350,000 per year (0.06 per cent to the delivery rate), the impact could be described as modest, particularly in consideration of the fact that the rate impact will decline each year subsequent to 2012. Also as described in response to BCUC IR 1.5.12, the operating costs of the Cauldron are generally paid by the owner of Jack Poole Plaza, and not by either the shareholder or the ratepayers.

The FEU consider the Cauldron to be part of Community Investment, which provides value both through the intrinsic value of good corporate citizenship but also to facilitate community acceptance of the FEU's ongoing operations. As such, the FEU consider the Cauldron to meet the definition of an asset and be used and useful in that it is contributing to the provision of utility service for the years it is in operation, through the potential reduction of costs and other community relation benefits. In addition, the Cauldron is used for ceremonial purposes and consumes gas which puts load on the system and revenues which are for the benefit of all customers and either paid for by the shareholder or third parties. As such, the FEU do not believe the Cauldron should have been expensed in the year incurred, and this treatment has been accepted by the Companies' auditors.

For a discussion of potential benefits to the FortisBC brand from the Cauldron and other Community Investment costs, and why these types of costs are appropriately recovered in rates as a cost of providing service, please see the response to BCUC IR 2.28.1.

3.2 Please explain how this asset is "used and useful" to the Utility gas assets of the Company and why it is appropriate to include the asset in rate base and what future benefit the ratepayers receive for this asset and why it meets the definition of an asset?

Response:

Please see the response to BCUC IR 2.3.1.

3.3 Should these costs be expensed in the year incurred thus not making them recoverable from ratepayers in the future?

Response:

Please see the response to BCUC 2.3.1.

3.4 Please explain if the Olympic Cauldron would qualify as a "modest" cost?

Response:

Please see the response to BCUC IR 2.3.1.

3.5 Was the cost of the Olympic Cauldron split 50/50 between ratepayers and the Shareholders?

Response:

Please see the response to BCUC IR2.3.1.

3.6 Does the FortisBC brand benefit from the contribution towards the Cauldron? If so, should a portion of these costs be charged to the shareholder?

Response:

Please see the response to BCUC IR 2.3.1.

3.7 Has FEU taken any steps to prevent the FortisBC brand from benefiting from the Cauldron? If so, what are they?

Response:

Please see the response to BCUC IR2.3.1.

4.0 Reference: ES & ER 2010 and 2011 Review - Mainland

Exhibit B-9, BCUC IR 1.9.3

Amalgamation

"2. While the FEU expect that there will be some localized impact of lower rates in FEVI or FEW on natural gas use and GHG emissions, FEI's customers will be paying higher delivery rates as a result of amalgamation. FEI customers may respond to the permanent increase in their rates from amalgamation and rate harmonization/postage stamping with a small reduction in their gas use. Even a relatively small reduction in use per customer for FEI's customers, when multiplied by the much larger FEI customer base, can have the effect of offsetting a significant portion of any increased load on Vancouver Island and in Whistler. Any increased load for FEVI and FEW may not be exactly the same as the decreased load for FEI but the FEU expect the net difference to be small."

4.1 Please provide the latest price elasticity of demand for FEI, FEVI and FEW's residential and commercial customers.

Response:

The FEU's analysis indicates the price elasticity of demand coefficient for FEI residential customers is approximately -0.22 and for FEI commercial customers is approximately -0.19.

The FEU's analysis of FEW and FEVI did not result in reliable elasticity estimates. The regressions resulted in very low R-squared results (less than 0.10 in several cases), p-values that were not significant for the resulting parameters and in several cases implausible results. In these implausible cases the models returned satisfactory R-squared results and p-values, but the model resulted in positive elasticity. This would imply that when prices go up, so does consumption, the opposite of what economic theory says about price elasticity. As a result, these models were rejected. There are several potential causes for these results. One reasonable explanation is that there are other factors driving the decline in UPC, overpowering any effects that price has on consumption.

However, the American Gas Association ("AGA") estimated long-run price elasticity of -0.18 and concluded that their price elasticity estimates were "relatively consistent with previous works on this subject"[4].

[4] Joutz, F. and Trost, R.P., (2007) "An Economic Analysis of Consumer Response to Natural Gas Prices", Prepared for the American Gas Association

Given that the AGA's elasticity numbers are similar to those estimated by the FEU for FEI, the FEU believe that it is reasonable to estimate that the price elasticity for FEW and FEVI would likely range between -0.18 and -0.22.

4.2 Has FEU analyzed the possibility of existing FEVI and FEW customers switching from electricity to gas due to lower gas rates? If not, why not?

<u>Response:</u>

The FEU have not completed a formal analysis regarding the possibility of existing FEVI and FEW customers switching from electricity to natural gas due to lower gas rates. However, the FEU have considered the possibility of existing FEVI and FEW customers switching from electricity to natural gas due to lower gas rates and the Companies do not believe this will happen to a material extent. There are many factors considered by customers when making fuel choice decisions and, as a result, there is uncertainty regarding the number of customers who might switch from electricity to natural gas. While non-economic factors such as comfort, ease of use and the environment (e.g. greenhouse gas emissions) may be part of customers' decision making, economic factors also play a significant role. While natural gas rates may currently be competitive with electricity rates on a variable-cost basis for most applications, natural gas is challenged in competing with electricity for some applications, particularly water heating, if the upfront capital costs associated with natural gas space and water heating equipment are included[5]. Furthermore, any increases in future natural gas market prices could add to this competitive challenge for both space and hot water heating applications. Also, uncertainty regarding future electricity rate increases and the carbon tax on natural gas after 2012 will likely also impact the number of customers who consider switching fuels in the future.

An even larger obstacle in many cases for customers contemplating switching from electricity to natural gas for space and water heating purposes is that costly retrofits are needed for ducting or other equipment to distribute the heat within the dwelling. Typically, it is much easier for natural gas customers to switch to electricity than electricity customers to switch to natural gas given the greater difficulty and cost in installing natural gas equipment compared to installing baseboards for electricity heating.

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[5] Section 4.4.5.4 of the Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Review of Price Risk Management and Hedging Strategy Report dated January 27, 2011.

4.3 If the lower rates in FEVI or FEW increases natural gas use and the small increase in FEI rates has no impact on FEI use, could this result in higher total natural gas use? Please discuss and explain if this could also result in higher GHG emissions.

Response:

As discussed in BCUC IR 1.9.1, the FEU believe that the primary consideration with respect to whether amalgamation is in the public interest is the upward pressure on rates on Vancouver Island and the ability of Whistler to attract and maintain load relative to other energy sources, for the long-term benefit of customers and the shareholder.

Based on the assumption that the question relates to existing natural gas customers only, if the hypothetical scenario provided in the question was to happen, it follows logically that if FEVI and FEW customers use more gas and FEI customers do not change their usage that there will be higher total natural gas use in the province and higher resulting GHG emissions.

However, the FEU do not believe that the hypothetical scenario set out in the question is likely to occur. As indicated in the response to BCUC IR 2.4.1, the available evidence suggests that the price elasticity response of FEI customers is likely to be similar to that of FEVI or FEW customers. FEI customers may respond to the permanent rate increases from amalgamation and rate postage stamping with a decrease in their gas consumption that in aggregate could offset much or all of the increased use by FEVI and FEW customers arising from the corresponding rate decreases that will occur for them.

Further, as indicated in the Application (Section 4), FEU expects use per customer to continue to decline, driven by factors such as public policy, energy efficient appliances and demand-side management programs. These factors will continue to reduce the total gas consumption in the Province, regardless of whether amalgamation occurs.

If the scope of the question includes the potential for increased gas usage through the addition of new customers, then there are a number of possible variables that would influence the extent of increased gas usage and whether this would result in higher GHG emissions. For example, whether higher GHG emissions would result depends on what the new customers are switching to natural gas from. If natural gas use increases on Vancouver Island as a result of customers switching from other fuel sources that emit higher GHGs such as heating oil or propane, then natural gas use may increase but this would not result in higher GHG emissions. The energy switch would be a move to a cleaner fuel that will support the Province's goal of lower GHGs.

Another variable that could impact the amount of natural gas use by new customers due to lower postage stamp rates on Vancouver Island and Whistler is the amount of customer contribution required for system extensions and the potential impact of this on customer additions. New customers that wish to attach to the distribution system today must pass a main extension test (MX Test) which is based on a forecast of delivery revenues for the customers to be added and the incremental costs of attaching them. Main extensions that do not meet the profitability threshold can make a capital contribution to bring them up to the acceptable level. Upon amalgamation, it is likely that more FEVI and FEW mains extensions will be required to pay a contribution as the forecast net cash inflows will be lower due to the reductions to the FEVI and FEW delivery rates from amalgamation and rate postage stamping. With more customers required to pay a contribution it is possible that fewer main extensions will proceed and in turn fewer customers will be added to the FEVI and FEW service areas. This could partially offset any potential higher natural gas use in FEVI and FEW due to fuel switching.

In summary, the FEU believe that the case for amalgamation should primarily be determined based on rate pressure for Vancouver Island and Whistler's ability to attract and retain customers – benefits which exceed any potential implications for British Columbia's energy objectives. Further, as discussed in BCUC IR 1.9.3, the FEU believe that there will be no material impacts in the Province as a whole with respect to customers using natural gas over electricity or on GHG emissions in BC as a result of amalgamation and postage stamp rates.

5.0 Reference: Consolidated Cost of Service

Exhibit B-9, BCUC IR 1.10.1

5.1 Please clarify under what section of the *Utilities Commission Act* (UCA), sections 59-61 allows for hypothetical ratemaking contemplating a potential transaction?

Response:

The Companies disagree with the characterization of the order they are seeking as "hypothetical ratemaking." The Companies will seek approval to amalgamate as part of a rate design application ("Amalgamation and Rate Design Phase 'A' Application") that will be filed later this year. Upon amalgamation, the amalgamated entity will be the continuation of the existing FEU and will carry on the existing public utility services of the FEU. The rate design will establish 2013 rates for the amalgamated entity based on the 2013 costs being proposed in this Application. Thus, in this proceeding, the Companies are seeking approval of an initial component of the rates for the amalgamated entity. Assuming the Commission finds the amalgamation to be in the public interest, the ultimate approval of the rates for the amalgamated entity would be conditional on the order of the Lieutenant Governor in Council consenting to the amalgamation. The Commission is able to make orders contingent on future events pursuant to section 90 of the *Utilities Commission Act.*

5.2 Does the UCA sections 59-61 only allow for ratemaking based on approved utility operations? If not, please clarify by reference to the text of the act that allows the Commission to consider potential, non-approved terms and conditions for the purposes of ratemaking?

Response:

As explained in the response to BCUC IR 2.5.1, the FEU upon amalgamation will continue as one company (one legal entity). The current services provided by the current three entities will continue, and the assets owned by the three entities will not be transferred or disposed of. Rather, as a result of the amalgamation, the assets owned by the three entities will be owned by the one company that continues after the amalgamation, the operations of the amalgamated entity will reflect the approved operations of the current three utilities, and the services provided will be based on existing approved terms and conditions for the three utilities. Thus, the amalgamated cost of service would be based on "approved utility operations".

5.3 If i) the amalgamated cost of service of FEU was approved within this application and ii) amalgamation was approved by the Commission and, as a result, changes were made to either ROE or interest mechanism of any/all of the components of FEU at that time, what does FEU expect to be the resulting amalgamated cost of service for the new entity?

Response:

Please refer to BCUC IR 1.10.7 and BCUC IR 1.10.8. As stated in the response to BCUC IR 1.10.8:

> *"The FEU intend to file evidence with respect to ROE for the amalgamated entity in the Amalgamation and Rate Design Phase 'A' application later this year. FEU will seek approval in the Amalgamation and Rate Design application to flow through Commission approved ROE and capital structure changes to the cost of service and rates, if applicable."*

The FEU clarify, therefore, that the request for approval of the amalgamated cost of service is subject to any changes in the return on rate base approved by the Commission as a result of the FEU's Amalgamation and Phase "A" Rate Design Application.

Typically, the FEU administer changes in capital structure and ROE as flow-through items to the revenue requirements. That is, the cost of service is recalculated to reflect the approved capital structure and ROE, and subsequently, the delivery rates are also recalculated to reflect the change. This practice is consistent with the flow-through treatment of changes to the approved ROE throughout FEI's 2004-2009 PBR, and most recently, with the treatment of changes to the approved ROE and capital structure pertaining to the 2009 ROE and Capital Structure Application as reflected in the FEU 2010 and 2011 delivery rates.

As discussed in the response to BCUC IR 1.10.7, if amalgamation is approved, items such as capital structure, return on equity and interest (i.e. collectively, the return on rate base) would be calculated in the same manner as today for each of the individual entities. If through the FEU's Amalgamation and Phase "A" Rate Design Application, the Commission approves changes to the rates used in the calculation of the return on rate base, the amalgamated cost of service would be revised to reflect these changes. Depending on the timing of approval, the amalgamated delivery rates for 2013 would be recalculated to reflect this change in the cost of service. Alternatively, the FEU may propose to capture the impact of the change in a deferral account for disposition through future rates or through a delivery rate rider.

Section 1.2.5.2 of the Application (Exhibit B-1) provides the rationale for the request for approval of the amalgamated cost of service. Approval of the amalgamated cost of service (the sum of the individual utilities' cost of service) provides the necessary platform for performing the cost of service analysis for a postage stamp rate design for the amalgamated entity. It is, therefore, efficient to address the combined cost of service together with other revenue requirements issues in this process.

6.0 Reference: Exhibit B-9 Response to BCUC IR 1.26.1

EEC Programs' Impact on UPC

For the TGVI service region in the year 2010, there is negative gross savings estimated at 1,952 GJ and a negative savings of 0.02 GJ/customer due to the high carbon fuel switching program.

6.1 How many customers participated in the high carbon fuel switching program on Vancouver Island and what is the average GJ/customer for these participants?

Response:

For 2010, there were 149 participants in the high carbon fuel switching program in FEVI, and the average GJ/customer is 43 GJ in added load per year.

6.2 Does the high carbon fuel switching program have any impact on savings in 2011? If yes, please show the impact separately in order to compare it with the 2010's value.

Response:

Yes. The tables below illustrate the impact for 2011 and compare it with the value for 2010 for Residential, Affordable Housing and Joint initiatives programs only. The tables below illustrate that the high carbon fuel switching program on FEVI does have some impact on use per customer (UPC). In 2010, the program added 0.07 GJ's per customer, while in 2011 the program is forecasted to add 0.15 GJ's per customer based on a forecast of 403 participants. As EEC programs in FEVI territory are relatively new and given that FEVI is a relatively younger utility, opportunities for efficient appliance upgrades are lower than FEI. Hence it is reasonable to assume that the high carbon fuel switching program has a greater impact on UPC in the FEVI region. As the FEVI market matures, and additional EEC programs are introduced, the overall impact of high carbon fuel switching may become less pronounced on the overall UPC.

2010					
Service Region	**Residential Customers (2010)**	**Gross Savings - Excluding Fuel Switching program (GJs)**	**Gross Savings - Including Fuel Switching program (GJs)**	**Savings GJ/Customer Excluding Fuel Switching program**	**Savings GJ/Customer Including Fuel Switching program**
FEI[1]	760,559	109,276	108,025	0.14	0.14
FEVI[2]	90,671	4,455	(1,952)	0.05	(0.02)
Total	**851,230**	**113,731**	**106,073**	**0.13**	**0.12**

2011					
Service Region	**Residential Customers Forecast (2011)**	**Gross Savings - Excluding Fuel Switching program (GJs)**	**Gross Savings - Including Fuel Switching program (GJs)**	**Savings GJ/Customer Excluding Fuel Switching program**	**Savings GJ/Customer Including Fuel Switching program**
FEI[1]	766,724	123,438	119,998	0.16	0.16
FEVI[2]	92,999	18,352	4,592	0.20	0.05
Total	**859,723**	**141,790**	**124,590**	**0.16**	**0.14**

Notes:

[1] Rate 1 residential customers across all regions in FEI - LML,INL,COL,RSk (Not including FTN)

[2] Rate 1 residential customers in FEVI

[3] The negative savings is due to the result of high carbon fuel switching program

7.0 Reference: Exhibit B-9 Response to BCUC IR 26.1

Savings GJ/Customer

The tables in the Response to BCUC IR 25.3 and BCCUC IR 25.4 show that the average absolute values of the Residential UPC forecast variances for FEI and FEVI are respectively at 3.6 GJ and 2.7 GJ.

7.1 Since the impact on average UPC as a result of approved EEC funding for the Mainland and Vancouver Island are estimated at 0.12 GJ and 0.16 GJ for 2010 and 2011 respectively, is it fair to conclude that the estimated EEC savings have no or negligible impact on load forecasting?

Response:

Compared to the average Residential UPC forecasting variance, the relative size of the EEC reduction is small. Estimated EEC savings are not used in the forecasting of the UPC. Instead, such factors are implicit in the historic data we use to develop the UPC forecast.

Compared to the average annual UPC reduction, the EEC contribution is significant. As shown in Figure 4.4-2 the average annual decline in Mainland UPC is forecast to be 0.9 GJ for the forecast period. In 2010 EEC is expected to account for 0.12 GJ of this reduction or 13%. In 2011 this value goes up to 18%.

On Vancouver Island, the average annual UPC reduction is higher so the relative contribution from EEC initiatives is smaller at 12% and 9% respectively.

8.0 Reference: Exhibit B-9 Response to BCUC IR 1.30.1

Decline in UPC

The Response to BCUC IR 30.1 says that the changing mix of housing stock is one of the many factors that could contribute to the decline in UPC for the Mainland region.

8.1 Please comment if, and how, the information in the response serves notice to FEU that a new cost of service study should incorporate assessment of different revenue cost ratios of residential customers in different dwelling types.

Response:

The FEU intends to review its residential rate structure and offerings as part of the Rate Design Phase 'B' Application, to be filed in the second half of 2012.

While the shift in housing mix (towards more multi-family dwellings) does contribute towards declining residential use rates, it is not the only driver. Changes to building codes, improvements in appliance efficiencies, and also changes in customer behaviour towards efficiency and conservation are also significant.

In assessing its residential rate structure and offerings, the FEU will evaluate a number of variables and make changes (if appropriate) to its residential rate in the Rate Design Phase 'B' Application.

8.2 Since the downward trend is around 1.0 GJ per year per customer and the savings from EEC is estimated at around 0.12 to 0.14 GJ, please list: (a) the other contributing factors; and (b) the proportion of each contributing factor to the annual decline for the Mainland region.

Response:

Other contributing factors may include:

- Efficiency upgrades, such as to appliances, insulation, windows, and doors, without any associated EEC incentives;
- Technological advances;

Natural gas prices and competing fuel pricing;

- Public policies and programs including tax policy (HST and carbon tax) and BC government policy stating that all new homes built after January 2009 must install a furnace with an efficiency level of 90% or higher;
- Changes to the appliances installed and used in the home for heating, hot water, cooking and decorative purposes (fireplaces);
- Behaviour changes by the people in the home; and
- Changes in building codes.

All factors are implicit in our historic use rate data. Other than EEC reductions[6] we are not able to accurately determine the relative contribution of any factor in our historic use rate data. Additionally none of these discrete factors form direct inputs into our forecasting methodology. Consistent with past practices, historical normalized use rate data alone is used to forecast future short-term use rates.

8.3 To the best of FEI's knowledge, is there a floor to the decline in UPC in the short run, i.e., in the next 1 to 3 years?

Response:

FEI is unable to conclude that there is a floor to the decline in UPC in the short run. Over the past decade, the residential UPC has been declining, with the exception of 2009. The rate by which UPC declines varies every year. Although the average decrease for the previous three years is -0.9 GJ, the annual change on UPC from 2008 to 2010 was -3.1 GJ, 0.7 GJ and -0.4 GJ, respectively.

Although the data is inconclusive, at this time it seems unlikely that there is a floor to the decline in UPC in the short term, considering the factors that are at work lowering UPC values. Government policy, appliance replacement, the changing mix of housing type and other factors (see response to BCUC IR 2.8.2) all contribute to lower UPC values and these influences are expected to continue beyond the short term.

Although a floor to the decline in UPC could be expected, it is challenging to forecast the timing. As all factors affecting the UPC are implicit in the historic data, the recent normalized UPC remains the best estimate for the short term.

---

6 The method to estimate the UPC reduction due to EEC initiatives is covered in BCUC IR 1.26.0.

9.0 Reference: Exhibit B-9 Response to BCUC IR 1.35.1

Decline in UPC

The Response to BCUC IR 35.1 states that FEVI is declining approximately 3 times as fast as the Mainland. It also states that the frequency tables do not provide the mix of new and existing customers and that FEVI believes it is reasonable to assume the changes in existing customers behavior account for a portion of those low volume customers.

9.1 Based on the latest REUS sample or based on other information source such as FEU's database, please provide the number of fireplace only customers in each region of FEU's service area.

Response:

	Homes with only a natural gas fireplace			
	Homes Built Prior to 2006[1]		Homes Built 2006 - 2010[2]	
Lower Mainland	2.10%	10,610	3.40%	823
Vancouver Island	5.40%	4,107	11.30%	1,538
Interior	1.60%	3,500	3.00%	399

[1] 2008 Residential End Use Study

[2] 2010 Residential New Construction Research. The study only looked at new construction and did not account for services installed in between 2006 and 2010 in homes built prior to 2006.

9.2 Please provide, for comparison purposes, a table showing the number of new customers each year (number, percentage of total customers) between 2006 to 2010 for the Mainland and Vancouver Island regions.

Response:

Mainland

	New Customers	Total Customers	Percent of New Customers
2006	13,397	809,718	2%
2007	15,485	822,687	2%
2008	14,543	831,886	2%
2009	9,805	836,978	1%
2010	9,587	843,845	1%

Vancouver Island

	New Customers	Total Customers	Percent of New Customers
2006	4,322	87,361	5%
2007	4,080	91,242	4%
2008	3,771	94,771	4%
2009	3,165	97,704	3%
2010	2,419	100,136	2%

The tables above show that the proportion of new customers is relatively higher in Vancouver Island as compared to Mainland; this is because of the smaller customer base in Vancouver Island. Therefore, if there was a similar change in customer behaviour in both utilities, it is likely that the impact on average UPC will be higher in Vancouver Island as compared to Mainland.

10.0 Reference: Growth Capital Expenditures

Exhibit B-9, BCUC 1.34.1

Residential Main Extension

10.1 Please complete the Main Extension Analysis table below for the FEI and FEVI **Residential Rate Class**. Calculate the maximum capital expenditure for the use per customer using the appropriate main extension test for each year. Also provide the table in fully functional electronic format.

FEI Maximum Capital Expenditure Supported by Use Residential per Customer (GJ/Year)

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Use Per Customer (GJ/Year)						
Average Main Cost per Customer						
Average Service Line Cost per Customer						
Maximum Capital Expenditure per Customer						

Response:

The response provided in BCUC IR 1.34.1, represented all rate classes in aggregate. FEI and FEVI Residential rate class customer information cannot be provided individually as the data is not readily available. With the Companies' current information systems, residential rate class customer information cannot be separated from other rate classes as some main extension projects consist of multiple rate classes.

11.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.38.2 and IR 1.38.5, pp. 121-123

Amalgamation of Annual Contracting Plans

"Similarly if full amalgamation does not proceed, a gas cost recovery methodology will be established based on a single portfolio of gas resources for all entities. This principle is already in place for FEW, whereby the FEI portfolio is based on meeting the combined requirements including those for FEW." (BCUC IR 1.38.2)

"The FEU are contemplating proposing to move to a single gas portfolio to serve the combined requirements of FEI, FEVI and FEW. Under this scenario, the costs of the entire portfolio will be captured under one entity operating the single portfolio: therefore, costs will not be tracked separately for FEI and FEVI. Instead, in the absence of full amalgamation, once the actual costs are captured within the single portfolio, those costs are expected to be reallocated back to and recovered from the sales customers within the various rate classes of the individual entities via appropriate gas cost allocation and recovery mechanisms." (BCUC IR 1.38.5)

11.1 Please confirm that the FEW gas costs are currently determined by mapping the FEW customers to the equivalent of FEI Rate Schedule 3.

Response:

Confirmed.

Pursuant to Commission Order No. G-39-09, dated April 7, 2009, the complete amalgamation of the gas supply portfolios for FEW and FEI was effected January 1, 2010. For gas cost recovery rate setting purposes, and based on the load factor data, the single FEW General Service Rate (SGS) rate class was mapped to the equivalent FEI Lower Mainland Rate Schedule 3 rate class.

11.2 Does FEU anticipate that the allocation of gas costs in an amalgamated gas portfolio would be accomplished by mapping FEVI rate classes to an equivalent FEI rate class?

Response:

The pending Amalgamation and Rate Design Phase 'A' Application, to be filed in Fall 2011, will address the rate design and cost allocation issues arising from amalgamation of the entities, including the cost allocation of gas costs. At this point, however, in the event full amalgamation is approved and the delivery, commodity, and midstream rates for the FEU are harmonized, the FEU anticipate that for gas cost recovery rate setting purposes the gas costs within an amalgamated gas supply portfolio would be accomplished by mapping the FEVI rate classes to the equivalent FEI rate classes.

11.3 Please confirm that LNG Mitigation Revenue is currently a component of Other Revenue in the delivery margin for FEVI and that conversely there will be an equivalent component of gas cost for FEI based on the rate for Mt. Hayes LNG Service under the Storage and Delivery Agreement between FEI and FEVI. If this is not a correct description, please describe the nature of the LNG Mitigation Revenue from the perspectives of FEVI and FEI respectively.

Response:

Confirmed.

11.3.1 When the proposed amalgamation of the gas portfolios commences November 1, 2012, will the LNG Mitigation Revenue continue to be allocated to the FEVI delivery margin?

Response:

Please refer to the responses to BCUC IRs 2.11.2 and 2.11.3

Within the pending Amalgamation and Rate Design Phase 'A' Application, to be filed in Fall 2011, the FEU will deal with any rate design issues arising from amalgamation of the entities, including those related to moving to a single gas supply portfolio, such as the recovery of costs related to Mt. Hayes LNG service.

It is now expected that in the absence of full amalgamation FEVI and FEI would maintain separate gas supply portfolios, and the current treatment of costs and revenues associated with

Mt. Hayes LNG service under the Storage and Delivery Agreement between FEVI and FEI would continue.

11.3.2 When the gas portfolios are amalgamated effective November 1, 2012 as proposed, will the charge for Mt Hayes LNG Service under the Storage and Delivery Agreement be recovered through the single amalgamated gas portfolio?

Response:

Please refer to the responses to BCUC IRs 2.11.2 and 2.11.3.1.

11.3.3 How will the LNG Mitigation Revenue be allocated if the gas portfolio is amalgamated but full amalgamation is not approved?

Response:

Please refer to the responses to BCUC IRs 2.11.2 and 2.11.3.1.

11.3.4 If the full amalgamation is approved, does the Storage and Delivery Agreement between FEI and FEVI terminate?

Response:

If full amalgamation of the entities is approved, upon the amalgamation, the obligations, rights and assets of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are thus cancelled.

11.4 Please confirm that the FEVI Wheeling Charge is currently delivery margin revenue for FEI and it is a component of gas cost for FEVI. If this is not a correct description, please describe the nature of the FEVI Wheeling Charge from the perspectives of FEVI and FEI perspectives.

Response:

Not confirmed. In both companies, the Wheeling Agreement is included as a component of the delivery margin. That is, the wheeling charges under the Wheeling Agreement between FEI and FEVI are not a component of gas costs for either entity.

In the case of FEVI, the costs associated with the Wheeling Agreement with FEI reside in delivery margin and are categorized as Transportation Costs. Please refer to Section 3.3.2.4 of the Application for a description of the transportation costs included in FEVI's delivery margin. Please also refer to Section 7.2, schedules 4-6, line 27.

In the case of FEI, the revenues associated with the Wheeling Agreement with FEVI reside in delivery margin and are categorized as Other Revenue. Please refer to Section 5.5.3 of the Application as well as Section 7.1, schedules 18-20, line 15.

11.4.1 When the gas portfolios are amalgamated effective November 1, 2012 as proposed, how will the FEVI Wheeling Charge be handled? Will it be recovered through the single amalgamated gas portfolio? Will the FEVI Wheeling Charge continue to be allocated to the FEI delivery margin?

Response:

Please refer to the responses to BCUC IRs 2.11.2 and 2.11.4.

In the absence of full amalgamation, it is now expected that FEVI and FEI would maintain separate gas supply portfolios. Regardless, amalgamation of the gas cost portfolios does not impact the allocation of the FEVI wheeling charge. In both FEI and FEVI, the Wheeling Agreement is included as a component of the delivery margin and is not a component of the cost of gas.

The pending Amalgamation and Rate Design Phase 'A' Application, to be filed in Fall 2011, will seek approval for a full legal amalgamation of the entities as well as address the rate design and cost allocation issues arising from amalgamation, including the cost allocation of the transmission system related costs. If full amalgamation of the entities is approved, upon the amalgamation, the obligations, rights and assets of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are thus cancelled.

11.4.2 How does the allocation of the FEVI Wheeling Charge for the period from November 1, 2012 to December 31, 2012 impact the balances in FEVI's GCVA and RDSA accounts?

Response:

Please refer to the response to BCUC IR 2.11.4.1.

The allocation of the FEVI wheeling charge for the period from November 1, 2012 to December 31, 2012 will impact the RSDA to the extent that FEVI wheeling charges vary from forecast. The RSDA account captures the differences between the net revenues received and the actual cost of service, excluding O&M variances from forecast. Therefore, notionally, any change in FEVI wheeling charges from forecast would be captured in the RSDA. However, because the FEVI wheeling charge is based on a contract which outlines a specified rate and volume, a variance is not expected to occur and thus, there would be no impact to the balance of FEVI's RSDA account.

As discussed in the response to BCUC IR 2.11.4, the wheeling charges under the Wheeling Agreement between FEI and FEVI are not a component of cost of gas for either entity and therefore have no impact on the GCVA.

11.4.3 Will the allocation of the FEVI Wheeling Charge change when the full amalgamation goes ahead as proposed? If so, describe how it will change.

Response:

As discussed in Section 3.3.5.1 of the Application, if full amalgamation of the entities is approved, upon the amalgamation, the obligations, rights and assets of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are thus cancelled. Therefore, as it pertains to the FEVI wheeling charge, the other revenue in FEI is entirely offset by the transportation costs in FEVI upon amalgamation of the delivery cost of service. Please refer to Section 7.5, Schedules 1 and 2, column 7, lines 6 and 9 (notes 2 and 4) which identify these adjustments.

The pending Amalgamation and Rate Design Phase 'A' Application, to be filed in Fall 2011, will address the rate design and cost allocation issues arising from amalgamation of the entities, including the cost allocation of the transmission system related costs.

11.4.4 How does the allocation of the FEVI Wheeling Charge for the period from January 1, 2013 to December 31, 2013 impact the balances in FEVI's GCVA and RDSA accounts?

Response:

Please refer to the responses to BCUC IRs 2.11.4, 2.11.4.1, 2.11.4.2, and 2.11.4.3.

The allocation of the FEVI wheeling charge for the period from January 1, 2013 to December 31, 2013 will impact the RSDA to the extent that amalgamation does not occur and FEVI wheeling charges vary from forecast. The RSDA account captures the differences between the net revenues received and the actual cost of service, excluding O&M variances from forecast. Therefore, notionally, any change in FEVI wheeling charges from forecast would be captured in the RSDA. However, because the FEVI wheeling charge is based on a contract which outlines a specified rate and volume, a variance is not expected to occur and thus, there would be no impact to the balance of FEVI's RSDA account. Furthermore, absent the impacts of amalgamation as discussed in the response to BCUC IR 2.11.4.3, a change to the allocation of the costs and revenues related to the Wheeling Agreement is not expected for January 1, 2013 to December 31, 2013.

As discussed in the response to BCUC IR 2.11.4, the wheeling charges under the Wheeling Agreement between FEI and FEVI are not a component of cost of gas for either entity and therefore have no impact on the GCVA.

11.4.5 If the gas portfolios are amalgamated but the full amalgamation is not approved, is it anticipated that the allocation of the Wheeling Charge would continue as established for November 1, 2012 or would it change?

Response:

Please refer to the responses to BCUC IRs 2.11.2, 2.11.4, 2.11.4.1 and 2.11.4.3.

Please note that the FEU no longer intend to seek approval to move to a single gas portfolio in absence of full legal amalgamation of the utilities. Nevertheless, since the wheeling charges under the Wheeling Agreement between FEI and FEVI are not a component of cost of gas for either entity, the amalgamation of the gas portfolios, in the absence of full amalgamation, would not impact the allocation of the FEVI wheeling charge.

11.5 Please describe how the FEW Transportation Charge (charged to FEW by FEVI) has been allocated given that the FEW and FEI gas portfolios have already been amalgamated.

Response:

FEVI provides intercompany transportation service to FEW on the FEVI system with the resultant charges to FEW being treated as transportation costs that are part of FEW's delivery margin, and the offsetting credits are booked to FEVI as sales revenue. The FEW transportation charges paid to FEVI are not a component of gas costs for either entity. Thus, the amalgamation of the FEW and FEI gas supply portfolios has no effect on the allocation of these costs.

11.5.1 How will the allocation of the FEW Transportation Charge change from a gas cost and delivery margin perspective for FEW, FEI and FEVI when the gas portfolios are amalgamated effective November 1, 2012?

Response:

Please refer to the responses to BCUC IRs 2.11.2, 2.11.4 to 2.11.4.5, and 2.11.5.

The FEW transportation charges paid to FEVI are not a component of gas costs for either entity. If full amalgamation of the entities is approved, upon the amalgamation, the obligations, rights and assets of the amalgamating companies are in effect merged and the contracts between the amalgamating companies are thus cancelled.

The pending Amalgamation and Rate Design Phase 'A' Application, to be filed in Fall 2011, will deal with any rate design and cost allocation issues arising from amalgamation of the entities, including the cost allocation of the transmission system related costs.

11.5.2 How does the allocation of the FEW Transportation Charge compare to allocation of the FEVI Wheeling Charge once the gas portfolios are amalgamated effective November 1, 2012 and then once the full amalgamation goes ahead?

Response:

Please refer to the responses to BCUC IRs 2.11.2, 2.11.4 to 2.11.4.5, 2.11.5, and 2.11.5.1.

12.0 Reference: Summary of Forecast 2012 & 2013 Operating Costs

Exhibit B-9, BCUC IR 1.45.1, pp. 140-143

Operating Costs by Cost Driver

While FEU may not track changes in actual O&M by cost driver, the data in the Application has categorized the O&M by cost driver for presentation and approval. Wording in the Application indicates that FEU has the actual cost data for prior years by activity level and unit costs:

"Also included in the Field Service Delivery category, driven by changes in activity levels and inflation in unit costs or a combination thereof, are additional funds …" [Ref: Section 5, p. 175]

The O&M data presented in the attachment to BCUC IR 1.45.1 is by high level resource code and high level activity code. The specific increases presented in the Application are not identified as to the related resource cost element and activity codes.

12.1 Please confirm that in the spreadsheet provided in response to BCUC IR 1.45.1 the Tab "Combined Activity 2 Rpt" has incorrectly not included the costs from Tab "Combined Activity 1 Rpt."

Response:

Confirmed. Attachment 12.1 contains a combined activity view with corrected totals. Please note that the 2012 and 2013 forecast O&M has been updated to agree to the Evidentiary Update (Exhibit B-11) filed on July 19, 2011.

The O&M increases in this Application are highlighted and explained by five O&M cost drivers. The 2010-2011 Application presented the O&M increases by seven O&M cost drivers.

Application for 2010 and 2011	Application for 2012 and 2013	Combined for Analysis
Accounting Changes		Accounting Changes
Labour Inflation and Benefits	Labour Inflation and Benefits	Labour Inflation and Benefits
Code and Regulations	Code and Regulations	Code and Regulations
Government Policy; Customer/Stakeholder Behaviours & Expectations	Customer & Stakeholder Expectations	Government, Customer & Stakeholder Expectations
Demographics	Demographics	Demographics
Service Enhancements	Service Standards & Reliability	Service Enhancements, Standards & Reliability

The organizational structure in this Application, for which the O&M increases are highlighted and explained, has increased to 13 groups from the 7 in 2010-2011.

Application for 2010 and 2011	Application for 2012 and 2013	Separated for Analysis
Distribution	Distribution	Distribution
Gas Supply and Transmission	Transmission	Transmission
	Energy Supply & Resource Development	Energy Supply & Resource Development
	Customer Service	Customer Service
Marketing and Development	Energy Solution & External Relations	Marketing, Development, Energy Solution & External Relations
Business and Information Technology Services	Information Technology	Business and Information Technology Services
Human Resources and Operations Governance	Human Resources	Human Resources
	Operations Engineering	Operations Engineering
	Operations Support	Operations Support
	Facilities	Facilities
	Environmental & Safety	Environmental & Safety
Finance and Regulatory Affairs	Finance and Regulatory	Finance and Regulatory
President	Corporate	President and Corporate

12.2 Please provide a spreadsheet which consolidates the O&M changes, for actual 2010 and 2011, and for proposed 2012 and 2013, by the cost drivers listed for analysis above, with a separate tab for each of the divisions listed above for analysis. The years should be on the horizontal axis and the cost drivers listed on the vertical axis, with the specific change items listed within each cost driver. The specific change items should be to the lowest level described in the Section 5 Cost of Service section, by cost driver, and presented for each year. The objective is to see the change in specific costs across the years. Should it be more appropriate to separate an analysis grouping further, such as Business and Information Technology Services into two entities, this can be useful as long as the historical view, from 2010 to 2013, is all in the same tab.

Response:

Please see the response to the BCUC IR 2.12.4.

12.3 Below is an example using Finance and Regulatory Affairs for Mainland. The actual spreadsheets should provide the consolidated information for all of FEU, without separating Lower Mainland, Vancouver Island, Whistler or Fort Nelson.

Finance and Regulatory Affairs	Actual 2009	Actual 2010	Forecast 2011	Proposed 2012	Proposed 2013
HST Savings				-1	
Accounting Changes					
Transfer gas supply accounting to CMAE		(400)			
Items previously in deferred		201			
Labour Inflation and Benefits		320	310	417	328
Code and Regulations					
Government, Customer & Stakeholder Expectations					
Regulatory Policy Mgrs (2) for Govt Policy		300			
BCUC increased fees				300	
Accounting fees for IFRS				250	
New Emission Reporting				90	
Demographics					
Service Enhancements, Standards & Reliability					
BCUC fees deferred		(364)			
Inflation			43	62	
Sub-total		57	353	1,118	328
2010-11 vs 2012-13			(42)		
Total	9,585	9,642	9,953	11,071	11,399

12.3.1 Please provide, for items of a unit cost or ongoing nature, an explanation for each cost item in 2012 or 2013 that is more than a 10% change from the actual costs incurred for that item in either 2010 or 2011. In the example above this would be the $417,000 which is 35% higher than the previous year, the $328,000 which is 21% lower than the previous year, the $43,000 which did not have an amount in the previous year, and the $62,000 which is 32% higher than the previous year.

Response:

Please see the response to BCUC IR 2.12.4.

12.3.2 Please provide, for one-time items, the underlying base costs. In the example above, what percentage increase is the $250,000 on the base accounting fees, and what percentage increase is the $90,000 on the base costs for reporting to governments?

Response:

Please see the response to BCUC IR 2.12.4.

12.4 If the cost driver analysis data requested above is not available for any reason, please provide, for every item of O&M cost identified for 2012 and 2013, the applicable organizational department, lowest level cost element, and lowest level activity code. Provide the equivalent lowest level department, cost element and activity code data for 2006 through 2013 in order to achieve more comparable information in each year from 2006 through 2013 for each O&M item identified in 2012 and 2013. This much more granular data analysis will result in a longer process but will allow the Commission Staff to analyze the requested increases in the context of the historical data.

Response:

As stated in the response to BCUC IR 1.45.1, the FEU do not track changes in actual O&M by cost driver and are unable to provide this information for the years requested by cost driver, particularly due to the many departmental changes that have occurred over the eight-year time period requested.

As agreed to by the Commission in Order No. G-153-07, Appendix A, pages 3 and 4:

> ***"2.3 Departure from the Uniform System of Accounts for O&M***
>
> *TGI requests approval to depart from using a portion of the Uniform System of Accounts for recording its O&M in Accounts 600 to 999 and to prepare reports using the New Code of Accounts, providing both a resource-based view and an activity-view, as included in the Annual Review Material filing in Section A-5 O&M Expense and Attachment A-5. In April 2007 TGI filed its Annual Report to the Commission for the year ended December 31, 2006 using the New Code of Accounts, providing both a resource-based view and an activity view. The proposed reporting allows costs to be easily compared year over year regardless of organization structure and that once approved TGVI, Terasen Gas (Whistler) Inc. and TGI will report their O&M in this consistent manner going forward.*
>
> *On September 20, 2007, the Commission issued a letter detailing the progress and proposed reporting format (included as Attachment A-5 in the Advance Materials) from the working group wherein the Commission requested on the working group findings and results by September 27, 2007. No comments were received.*
>
> ***The Commission approves the TGI request to depart from using a portion of the Uniform System of Accounts for recording its O&M in Accounts 600 to 999 and to prepare reports using the New Code of Accounts, providing both a resource-based view and an activity-view. The Commission accepts that the New Code of Accounts is to provide consistent and informative reporting similar to the Commission's Uniform System of Accounts for Gas Utilities. Also, TGI is to request Commission approval for revisions to the New Code of Accounts. A revision may be due to an accounting rules change or operational change that necessitates a change to the New Code of Accounts. Changes to the New Code of Accounts for clarity does not need approval but should be reported to the Commission."***

The FEU note that providing more granular analysis than this does not achieve more comparable information, as suggested in the question. In fact, the more granular the analysis is, the less comparable it becomes due to changes in organizational structures and accounting policies.

Attachment 12.4 provides a fully functioning excel file containing actual and forecast activity view of O&M for the combined FEU, along with variance explanations for 2012 and 2013 where the variance is greater than 10% and is greater than or equal to $250 thousand.

The FEU note that the use of cost drivers to explain changes in O&M levels in the RRAs for 2010 through 2013, has been done to demonstrate the impacts of the many new and emerging challenges faced by the utilities. The analysis of O&M by activity codes or resource codes over time is not able to convey this same level of understanding, and therefore is not as useful for demonstrating required changes to levels of O&M funding in revenue requirement applications.

13.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.46.1, p. 144

Employees – Historical by category

The spreadsheet provided in response to BCUC IR 1.46.1 provides the FTE from 2009 to 2013 by expenditure category.

13.1 Please confirm the 17.8% increase in O&M FTE from 2009 Actual to 2010 Actual, which is 29% higher than the 13.8% expected increase in O&M FTE from the 2009 Actual to the 2010 Approved.

Response:

Confirmed. As explained in the response to BCUC IR 2.13.2, the timing of 2010 hiring happened later than originally anticipated. As a result, the FEU generated O&M savings early in the year which in turn allowed the FEU to advance hire some of the forecast 2011 FTEs later in 2010, while still managing to 2010 approved O&M levels.

13.2 Please explain which groups within FEU were increased above the amounts Approved, and explain where the budget was obtained for this extra increase in staffing.

Response:

Table 1 below shows the variance in FTE as at December 31 by department in those cases where the O&M 2010 Actual FTEs were greater than the O&M 2010 Approved FTE s for the FEU. The FTE O&M variances occurred for the following two reasons that did not result in a corresponding O&M budget variance:

- First, the timing of 2010 hiring happened later than originally anticipated. As a result, the FEU generated O&M savings early in the year which in turn allowed the FEU to advance hire some of the forecast 2011 FTEs later in 2010, while still managing to 2010 approved O&M levels.
- Second, by delaying certain projects/initiatives some business areas funded additional FTEs to perform higher priority work.

Temporary employees are recorded under the temp pool in the Human Resource Department; however, the business areas where such FTEs are employed (funding departments) are responsible for funding of the temporary employees' salaries. That is, HR shows additional FTEs while other departments provide the necessary funding. Therefore, in Table 1 below, the FEU has restated the 2010 Actual FTE to reflect the assignment of the 44 temporary FTEs to the applicable business areas.

The increase of 6 FTEs as compared to approved in deferral account FTEs for 2010 is related to EEC program launching and development within the Energy Solutions and External Relations business area and is discussed on pages 210 and 211 of the Application (Exhibit B-1).

Table 1: 2010 FEU O&M FTE

Business Area	2010 Actual	Temp FTEs	Actual Restated	2010 Approved	Diff.	Variance Explanation & Sources of Funding
Facilities	14	-	14	17	(3)	Vacant positions to be filled in 2011
Operations Engineering	108	12	120	119	1	Duration of employment did not cause budget challenges
Operations Support	76	1	77	86	(9)	Vacancies due to employee turnover
Customer Service	31	1	32	29	3	Savings from delayed hires in Q1 through Q2 paid for additional FTEs
Human Resources	116	(37)	79	71	8	Temp pool of 44 FTE 37* of which are paid for by other departments, additional FTE financed from late hiring and cross-charges to Transmission
Environmental & Safety	12	-	12	12	-	N/A
Information Technology	59	3	62	58	4	Offset were found in consulting costs paid for additional FTE
Distribution	411	16	427	406	21	Certain initiatives were put on hold to finance the additional FTEs
Energy Solution & External Relations	95	1	96	88	8	Savings from delayed hires in Q1 through Q3 and restructuring 2 higher paid positions into lower pay grade paid for additional FTEs
Finance and Regulatory	68	2	70	69	1	Savings from employee turnover vacancies during the year allowed for 2 temporary FTEs at a year end.
Transmission	81	1	82	75	7	Early hire of Mt. Hayes LNG staff offset found by curtailing other departmental spending
President	1	-	1	2	(1)	President's retirement
Energy Supply & Resource Development excluding CMAE	20	-	20	21	(1)	Vacancies due to employee turnover
Sub Total	**1,092**	**-**	**1,092**	**1,053**	**39**	

In the process of responding to this question, the Companies discovered an error in the 2010 actual number of IT FTEs. For 2010 actuals, the total number of Mainland IT FTEs should have been 64 instead of 66, with the O&M FTEs increasing by 2, and the Capital/Deferral FTEs decreasing by 4 (6 instead of 10). Consequently, this also impacted the total number of FTEs included in Table 5.3-14 on page 159 of the RRA (Exhibit B-1). For 2010 actuals, the total number of Mainland FTEs should have been 1,314 instead of 1,316. Please note that this was an error in the presentation of the table only and does not impact the determination of the revenue requirements.

Corrected FTE tables are included below, including the table provided in the response to BCUC IR 1.46.1.

Revised table in response to BCUC IR 1.46.1:

Total Employees

FEU	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Capital	307	320	290	309	362	366	368
Capital/Deferral - Customer Service	0	7	7	7	336	15	13
Deferred - EEC	12	10	16	11	18	19	19
Deferred - Other	3	0	0	0	0	0	0
CMAE	19	21	20	21	22	22	22
NGV & Biomethane - O&M	0	0	0	0	1	1	1
Operating & Maintenance	925	1,053	1,092	1,090	1,082	1,405	1,406
Total	1,266	1,411	1,425	1,438	1,821	1,828	1,829
Dependant Contractors Excluded		23	15	23	3	3	3

Thermal Energy Services employees not included in the 2012-2013 Revenue Requirements and Rates Application Table 5.3-14

Table 5.3-14: Growing Employees to Support In-Sourced Customer Service and Enhanced Reliability

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	1,294	1,314	1,311	1,692	1,701	1,701
Vancouver Island	111	107	122	124	123	124
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,411	1,425	1,438	1,821	1,828	1,829

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	298	282	287	671	358	358
Vancouver Island	39	31	40	45	42	42
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	337	313	327	716	400	400

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	996	1,032	1,024	1,021	1,343	1,343
Vancouver Island	72	76	82	79	81	82
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,074	1,112	1,111	1,105	1,428	1,429
Dependant Contractors excluded	23	15	23	3	3	3

Table 5.3-43: IT Department O&M Increases to Maintain Service Standards and Reliability

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	63	64	63	65	74	75
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	64	65	64	66	75	76

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	6	6	6	6	9	9
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	6	6	6	6	9	9

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	57	58	57	59	65	66
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	58	59	58	60	66	67

13.3 Please provide the types of expertise these new hires are bringing into the Company.

Response:

The majority of the new hires brought into the Companies since 2009 have been brought in to fill a variety of skill requirements ranging from distribution apprentices and other field personnel to technicians, technologists, as well as managers in customer service, energy efficiency and conservation, marketing and business development.

14.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.47.1, pp. 145-148

Employee/FTE – O&M by division

14.1 Please confirm if any of the 41 identified FTE require O&M funding, and if so the amount by each department/function. Please also provide the applicable page reference in Exhibit B-1 of each of the 41 FTE for the convenience of readers.

Response:

Please refer to the table below for the requested information. The 41 employees were also discussed in the response to BCUC IR 1.47.2.

Department			Employee Additions	Require O&M Funding ?	Incremental Funding	Incremental Funding	Incremental Funding	Applicable page reference in Section 5 of the 2012-2013 Application
					2011 Projected (000's)	2012 Forecast (000's)	2013 Forecast (000's)	
Distribution	Dependant contractors converted to regular employees (IBEW)	20		Primarily charged to capital work with the exception of training. Forecast assumption was for similar levels of training, therefore no O&M impact.	0	0	0	Page 166
Distribution	(planners, customer appointment setters)	12		Primarily capital work, O&M portion included in Regular Operations O&M.	0	100	0	Page 166
Distribution	Elimination of IBEW positions	-14		Primarily capital with the exception of O&M for training.	0	0	0	
Total Distribution			18					
Transmission			3	1 FTE funding not required for 2011 (offsets found in other programs/initiatives); 2 FTEs funding required for 2012.	0	142.1	47.2	2011 not discussed in application but included in 5.3.5.12, page 181; 2012 included in 5.3.5.15, page 185 (Service Standards and Reliability)
ES&RD excluding CMAE			2	FTEs added in 2011, used existing funding. O&M funding not required.	0	0	0	Page 188
Information Technology			2	Not required for 2011; yes for 2012 .	0	140	0	Page 222
Operations Engineering			17	In year 2011/2012 6.5 FTEs were added using the existing budget and in year 2012 - 10.5 FTEs attributable to LTSSP. Require O&M funding in 2012.	0	239	149	Page 231-232
Corporate/President			-1	No				Page 263
	Total		**41**					

15.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.48.1, pp. 149-151

Distribution O&M Expenditures and Employees – Service Standards & Reliability

The table presented in BCUC IR 1.48.1 contains the Service Standards & Reliability cost driver amounts for 2010 through 2013. The totals are: ($28,000) in 2010, $351,000 in 2011, $2,827,000 in 2012, and $1,646,000 in 2013.

"The table in the preamble for this question above is correct as to dollar amounts" [Ref: B-9, BCUC IR 1.48.1, p. 150]

The majority of the cost items listed has no amount for years prior to 2012 and none for 2013.

BCUC IR 1.54.1 requested, in part: "Please explain why there is no change in 2010, 2011 or 2013."

15.1 Please explain how these items go, in total from ($28,000) in 2010 and $351,000 in 2011 to $2,827,000 in 2012 and $1,646,000 in 2013. Please provide the items for 2010 and 2011 that add to the amounts for those years and explain why there are no corresponding costs for 2012 or 2013.

Response:

Several of the budget line items requested in 2012-2013 RRA under Service Standards and Reliability were previously requested under Codes and Regulations in the 2010-2011 RRA. These items were initiated in response to new or existing codes and regulations in the 2010-2011 RRA and therefore fell into the Codes and Regulations category. The subsequent additions, deletions and changes requested in 2012-2013 were the result of changes in levels of activity associated with the codes and were, therefore, in the Service Standards and Reliability category.

Attachment 15.1 includes an Excel spreadsheet summarizing FEI Distribution O&M incremental and decremental budget line items for the 2010-2013 period in the Codes and Regulation category and the Service Enhancements/Service Standards and Reliability category. In the 2012-2013 RRA, the "Service Enhancements" category was renamed the "Service Standards and Reliability" category. Referring to the preamble (first paragraph in the information request), we note that the 2010 and 2011 amounts quoted are for FEI and therefore tie to the excel spreadsheet (Section 4). The 2012 and 2013 amounts quoted were for the FEU in total, of which $2,520 thousand and $1,243 thousand are for FEI. The FEI amounts tie to the excel spreadsheet (Section 3 and 4) for those years.

The spreadsheet in Attachment 15.1 is divided into four sections:

1. 2010-2013 Codes and Regulations budget line items
2. 2010-2011 Service Enhancement budget line items
3. 2010-2013 Service Enhancements/Service Standards and Reliability budget line items
4. 2010-2013 Summary of all Incremental budget line items in both categories

A brief explanation of the categories is provided below:

- Section 1 – 2010-2013 Codes and Regulations is a summary of all budget line items requested under this category, with several line items removed to Section 3, 2010-2013 Service Standards and Reliability so that the same line item can be seen across all four years. For reference purposes, this section's line items listing matches the Code and Regulation Table C-6-16 page 362 of the 2010-2011 RRA excluding the line items removed to Section 3 to facilitate the year over year comparisons.
- Section 2 – 2010 Service Enhancements is a summary of all 2010-2011 budget line items requested under this category, with several line items removed to Section 3 2010-2013 Service Standards and Reliability so that the same line item can be seen across all four years. For reference purposes, this section's line items listing matches the Service Enhancements Table C-6-18 page 364 of the 2010-2011 RRA, excluding the line items removed to Section 3 to facilitate the year-over-year comparisons.
- Section 3 – 2010-2013 Service Standards and Reliability is a summary of all 2012-2013 budget line items requested under this category (matches response to BCUC IR 1.48.1) together with the 2010-2011 budget line items removed from Section 1 and Section 2 above. This has been done to facilitate the comparison of the same budget line item across all four years.
- Section 4 – 2010-2013 Summary is a summary of all incremental budget line items in both categories requested in the 2010-2011 RRA and 2012-2013 RRA showing the reconciliation of all requests to the three Sections above.

For several budget line items in Sections 1 and 2 (primarily 2010 and 2011 requests), there was no incremental amount requested for 2012 and 2013. Similarly, for several budget line items requested in Section 3 there were no incremental requests in 2013.

In terms of FEVI, FEW and Ft. Nelson, the last four items listed in the table to the initial information request, BCUC IR 1.48.1, and included in the response to BCUC IR 1.48.1, are related to those entities and therefore excluded from the FEI spreadsheet above. The FEVI 2010 and 2011 incremental and decremental changes by cost category are summarized in Table C-6-3 and Table C-6-4 on page 288 of the 2010-2011 FEVI RRA. Both the Code and Regulation and Service Enhancement cost driver categories show minor decreases from the 2009 projection.

15.2 For one-time items such as the Bay Street Bridge Crossing repairs, please confirm if there have been any similar single entity repair type activities across FEU in 2009, 2010 or 2011, and how these were funded.

Response:

During the period 2009 through 2011, a number of bridge and aerial crossing repairs were completed throughout the FEU service area but none amounting to the costs of the repairs required for the Bay Street Bridge in Victoria. These repairs, typically costing less than $20 thousand each, were funded from the regular O&M budgets and not identified as a significant line item in the budget or the Revenue Requirements Application. Cost estimates obtained for the repainting and adjustments for the Bay Street Bridge crossing were significant enough to warrant an explanation in the Application (page 177).

With stringent environmental and safety regulations in place for completing the work, and as the crossings age and weather, the FEU anticipate additional significant repair requirements will be identified for other bridge and aerial crossings in the future.

16.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.49.1, p. 154

Distribution – Consultants and Contractors

The response indicates a 26% increase from 2012 to 2013.

16.1 Please explain the 26% increase for Distribution use of Consultants and Contractors from 2012 to 2013.

Response:

The increase in Distribution consultant/contractor O&M expenditures in FEI from 2012 to 2013 is $795,000 and is comprised of the following:

- $500,000 - Long Term System Sustainment Assessments (RRA reference page 176)
- $115,000 – NGV operations/maintenance (RRA reference page 175)
- $68,000 – Biomethane operations/maintenance (RRA reference page 175)
- $112,000 - Field Service Delivery activities (leak survey $40,000, industrial meter set operations $28,000, various other miscellaneous field service activities totalling $44,000) (RRA reference page 174).

The increase in consultant/contractor O&M expenditures in FEVI from 2012 to 2013 is $330,000 and is comprised of the following:

- $330,000 – Bridge Repair (Oak Street, Victoria) (RRA reference page 177)

16.2 Please provide the Actual 2009 through Proposed 2013 consultant and contractor actuals/budgets separated by activity code for each of the divisions in consolidated FEU, and explain any year over year change exceeding 10%.

Response:

Attachment 16.2 contains a functioning excel file, in which consultant and contractor costs are shown by the three digit code activity view which is representative of the functional areas within the combined FEU. As resources such as internal labour versus consultant and contractor may be used interchangeably within a functional area (i.e. areas include 100 Distribution, 200 Transmission, etc.), the consultant and contractor information has been presented at a similar three digit activity code level. Due to materiality, brief variance explanations were provided only for the line items where the year over year variance was greater than 10% and was more than $50 thousand.

FEU highlights that the level of consultant and contractor spending in any given year by activity and analysis of the changes from year to year is relevant information, but that other considerations must be taken into account to ensure appropriate understanding. At a high level, excluding ABSU related costs during 2009 to 2011, consultant and contractor costs represent on average approximately 8% of the FEU's total gross O&M costs (reference response to BCUC 1.133.1 for O&M Resource View). For 2010 to 2011, even though spending at the activity code level varies in some cases over the 10% threshold, aggregate spending is projected to remain relatively flat at approximately $16 million per year.

Consultants and contractors are employed by the departments in FEU for different activities, providing expertise to complement existing FEU resources and address business requirements. Like any other resource available (i.e. internal labour), consultants and contractors are utilized by FEU to meet operational and business requirements in order to provide a safe and reliable delivery service to customers. As a result, changes in consultant and contractor spending from year to year at the activity code reflect resource decisions made by FEU to meet business requirements.

17.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.50.0, pp. 155-157

Distribution – ROW signage colour change

"The initiative to bring Transmission and Intermediate pipeline line markers in compliance with international standards is incremental to the ongoing replacement of line markers and is expected to be done over a five year period (2012-2016)." [Ref: B-9, BCUC IR 1.50.2]

"Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines (Figure 6.2-1) have been in service for 40 to 55 years. These aging assets will be facing an increasing rate of deterioration and be approaching the end of their service life leading to the need for replacement starting within the next 10 years." [Ref: B-1, Sec 6, p. 337]

17.1 Please confirm the costs of replacement of line markers for Transmission and Intermediate pipelines has been done previously under capital installation activities or under routine corrective O&M. Please confirm the routine corrective O&M budget has not been reduced.

Response:

When a Transmission or Intermediate pressure pipeline is installed or replaced or when an activity is completed that requires removal of the pipeline markers, all markers and signs on the section of pipeline impacted are installed to current Company and code requirements as a part of the work. If the work completed is capital, the new markers are charged to capital. Where the markers meet current standards and are in good condition, they are reused. In addition, regular patrol activities often identify missing or damaged markers and these are replaced as an O&M activity.

There has been no reduction in O&M budgets specific to maintaining pipeline markers or any other safety initiatives and equipment critical to maintaining the safety of the gas delivery assets. However, the previous amounts have been minimal as the work was completed as part of regular patrol and O&M activities. These activities will continue but a new program over and above the previous activity levels is required because it is not feasible to replace all of the markers through routine activities in a timely manner. There are no specific plans to replace all of the transmission and intermediate pressure pipelines over the next five years that would allow for the line markers to be replaced as part of that activity.

17.2 With a major capital replacement of lines starting in 10 years, why not simply replace the markers as the lines are replaced? Would this project be installing markers that will be replaced five years later?

Response:

We anticipate that the capital replacement of pipes, pipelines and associated assets will be underway starting within the next 10 years, with adequate lead time to begin replacement before the assets reach the end of their service life. In this RRA, the FEU are requesting O&M funding to develop a long-term replacement plan, to confirm the actual work required and the appropriate timeframe for the work, and do not anticipate that all pipelines will need to be replaced within the timeframes considered reasonable for replacement of markers.

If markers are replaced as part of this project, and subsequent to that a pipeline is replaced, the pipelines will, for the most part, be re-installed. Any time pipeline markers are removed as a result of activities over a pipeline, if those markers are to current standards and in acceptable condition, they are reinstalled.

Replacing the pipeline markers over the next five years will ensure the Mainland is brought into code compliance in a reasonable and timely manner. In order to ensure all markers are changed, the replacements will be performed as a focussed effort, but also in coordination with routine activities. Future work on the pipelines will not incur additional costs for markers beyond what would normally be expected due to aging, vandalism or damage as markers in acceptable condition will be reused.

"We believe it is important to be code compliant in a timely manner and anticipate completing the program for intermediate pressure pipelines by 2017. Therefore, relying on normal replacement as a means of upgrading the colour would result in an unacceptably long time to complete the program." [Ref: B-9, BCUC IR 1.50.3]

17.3 Please confirm there is no requirement under the ANSI Z535.1 code to change the colour of the markers within a specific timeframe.

Response:

Confirmed. ANSI Z535.1 does not specify any timeframe for changing the colours of the line markers. This is outside the scope of the standard. ANSI Z535.1, Clause 2, Scope, states:

> *"This standard sets forth the technical definitions, color standards, and color tolerances for safety colors."*

In addition, ANSI Z535.1 Clause 3.1, Intent goes on to state:

> *"The intent of this standard is to establish a Standard for Safety Colors that will alert and inform persons to take precautionary action or other appropriate action in the presence of hazards."*

Therefore, from a safety awareness aspect, it is important to be code compliant in a timely manner.

> *"While the new line markers will include the FortisBC name, this is not required."* [Ref: B-9, BCUC IR 1.50.4]

17.4 Please provide the wording required on the line markers under the ANSI Z535.1 standard.

Response:

There is no specific wording requirements in the code other than the requirement for the word "gas" or "propane" (see below). The wording on the line markers is based on FEU's interpretation of the code requirements below.

While ANSI Z535.1 does not actually provide the requirements, it refers the reader to ANSI A13.1.

ANSI A13.1, American National Standard Scheme for the Identification of Piping Systems, Clause 2.2.1 states:

> *"Flammable. This condition includes fluids which under ambient or expected operating conditions are a vapor or produce vapors that can be ignited and continue to burn in air. The term thus may apply, depending on service conditions, to fluids defined for other purposes as **flammable** or **combustible**."*

ANSI A13.1, Clause 3.1, Legend states in part:

"Identification may be accomplished by stenciling, the use of tape, or markers. In any situation, the number and location of identification markers shall be based on the particular piping system."

ANSI A13.1, Table 2, Designation of Colors, is presented below and specifies that the Designation of Colors for flammable fluids is safety yellow with black letters.

ASME A13.1-2007

Table 2 Designation of Colors

Fluid Service	Background Color	Letter Color	Color and Letter Sample
Fire quenching fluids	Safety red	White	Letters
Toxic and corrosive fluids	Safety orange	Black	Letters
Flammable fluids	Safety yellow	Black	Letters
Combustible fluids	Safety brown	White	Letters
Potable, cooling, boiler feed, and other water	Safety green	White	Letters
Compressed Air	Safety blue	White	Letters
To be defined by the user	Safety purple	White	Letters
To be defined by the user	Safety white	Black	Letters
To be defined by the user	Safety gray	White	Letters
To be defined by the user	Safety black	White	Letters

In addition to the requirements of ANSI Z535.1 and ANSI A13.1, CSA B149.1, Natural Gas and Propane Installation Code, Clause 6.17.a states:

"In every ***care*** *or* ***detention occupancy***, ***commercial***, ***industrial***, *and* ***assembly building***, *piping or tubing shall be identified by one of the following:*

(a) the entire piping or tubing system shall be painted yellow;

(b) the piping or tubing system shall be provided with yellow banding that has a minimum width of 1 in (25 mm); or

(c) the piping or tubing system shall be labelled or marked "GAS" or "PROPANE"†, as applicable, utilizing yellow labels or markings.*

When identified in accordance with Item (b) or (c), the identification intervals shall not exceed 20 ft (6 m)."

While CSA B149.1 is not specific to pipeline systems before the meter set, Clause 6.17 further supports the intent to standardize the marking of the natural gas piping systems based on the international colour yellow.

The FEU must adopt and comply with all applicable standards, both from a compliance perspective as well as a means of ensuring that customers, the public and first responders are given all possible opportunity to recognize the commodity and its inherent risks.

17.5 Please explain how Terasen updated the ROW markers following the name change from BC Gas.

Response:

As a result of the name change from BC Gas to Terasen Gas, an accelerated program was undertaken to include updates to signs and pipeline markers. The costs were paid for by Terasen Inc., not the utility.

As discussed in response to BCUC IR 1.50.4, the current requirement to change the markers is to comply with code. The timing of the new line markers allows for an opportunity to also incorporate the name change to FortisBC.

18.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.51.0, pp. 158-160

Distribution – Additional Asset Compliance Managers

*"**Current company policy requires** local managers to complete a number of audits per month; this combined with training and competency assessment programs **ensures** that FEU personnel complete quality work. This will continue to be a requirement of these managers.*

Changes introduced in the most recent version of CSA Z662 increase requirements for audits. The code requirements are:

CSA Z662 Clause M.16 states:

> *"Gas distribution companies **should also consider** having audits performed on their integrity management programs."*

CSA Z662 Clause N.5.3 states:

> *"Operating companies shall **identify** and **document** the personnel responsible for the various elements of the pipeline integrity management program, as identified in this Annex, including the following: … (f) **integrity program audit**s, reviews, and evaluations."*

[Ref: B-9, BCUC IR 1.51.3] [Emphasis added]

18.1 Please confirm that the CSA Z662 code requirement is to identify and document the personnel responsible but does not require a specific number of such personnel, and does not require personnel whose only responsibility is integrity program audits.

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

Confirmed. CSA Z662 requires that the Companies identify and document the personnel responsible for integrity management activities, including audits. It would be highly unusual for a code to specify the number of personnel required or expected to be required to do the work given that the code applies to a wide range of companies and not only the FEU.

Local managers complete audits of their personnel as a means of ongoing management of their activities including work quality as well as safety compliance. Audits completed by the Asset

Compliance Managers provide an "arm's length" perspective with no conflict of interest which is why the Companies believe the model of having personnel whose only responsibility is integrity program audits is more effective. The audits are targeted at ensuring the ongoing integrity of the assets.

The assignment of responsibilities and the resources requested are the minimum numbers required to meet the FEU's responsibilities as identified by Z662 and to ensure that the customers, public, employees and plant continue to be installed and maintained to safe and reliable standards.

19.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.52.0, pp. 161-162

Distribution – Standardization of locks and security devices

"In accordance with CSA Z662 and CSA Z246.1, the FEU must maintain adequate security measures to ensure only authorized personnel have the capacity to access facilities and operate equipment. Current control of keys to local locks is inadequate. … Changes in code requirements including CSA 662 and CSA Z246.1 require the operator to ensure adequate security protection of facilities;" [Ref: B-9, BCUC IR 1.52.1]

19.1 Please confirm the effective date for CSA Z662 and CSA Z246.1 and the date, if different, when FEU is required to meet the intent of the regulation. If the effective date was in 2009, please explain why action was not taken then.

Response:

By Information Letter #OGC 07-19, dated November 27, 2007, the Oil and Gas Commission advised of their adoption of CSA Z662-07, Oil and Gas Pipeline Systems.

By Information Letter #OGC 09-27, dated September 24, 2009, the Oil and Gas Commission advised of their intent to adopt CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems. No deadline for formal adoption was noted, however, comments were invited until December 31, 2009. FEU understands that the Oil and Gas Commission is on track to adopt CSA Z246.1 in 2012.

The improved key control program is required to address the anticipated adoption of CSA Z246.1 in 2012 as well as to improve general operating security at critical natural gas delivery facilities.

CSA Z662 does not prescribe specific measures for security for natural gas delivery facilities but assigns responsibility for appropriate measures to the operator. For example, CSA Z662-07, Clause 10.5.5 states the following, but provides no actual requirements.

"Conditions that can adversely affect the security of the pipeline system shall be corrected"

CSA Z246.1, Clause 9.3.8 states:

"High-quality locks should be used to deter access to important equipment, facilities, or areas. If using locks, the operator shall establish and document a key control procedure.

The key control procedure shall provide an issuance and return tracking system to prevent unauthorized use or loss of keys and locks."

As discussed in the Application (Exhibit B-1 Page 172) and in the response to BCUC IR 1.52.2, the key control procedure required by Z246.1 is not in place. While this concern has been identified for some time, there was no specific requirement to correct it. With heightened awareness of possible terrorist activities, both domestic and foreign, increased metal theft and vandalism, decreased public acceptance of unnecessary risk by pipeline operators and the public, and the anticipated adoption of CSA Z246.1 in 2012, the FEU believe now is the time to address the code requirements.

"2. Different keys are used in different areas across the Province limiting the ability to effectively move personnel as the work requires;

3. Different keys are used between Distribution and Transmission facilities limiting the ability to effectively move personnel between the work groups even though this happens regularly;

4. Past use of a single key type to all facilities has resulted in ***personnel, contractors and retirees*** *having access to field facilities that require more stringent control of access. For example,* ***a janitor with a key*** *to clean a muster building has access to all regulator stations as well;*

5. Past limited control of keys has resulted in keys to the FEU's facilities ***being retained by past employees and contractors****;" [Ref: B-9, BCUC IR 1.52.1] [Emphasis added]*

19.2 Please comment on the level of risk that FEU has been willing to live with up until 2012 compared to the level FEU finds acceptable in 2012 and going forward. Please explain why this re-keying and access control has not already been implemented.

<u>Response:</u>

To date there have been no incidents impacting the security of the natural gas delivery system as a result of unauthorized use of keys. The improved key control program is required to address the anticipated adoption of CSA Z246.1 as well as to improve general operating security at critical natural gas delivery facilities. With a heightened awareness of security concerns, both locally and abroad, as well as a reduced tolerance for risk by employees, customers and the public, and the requirements expected to be in place in the RRA period, the time has come to address the key control issues.

Please also refer to BCUC IR 2.19.1.

"Recent gas emergency events and exercises have raised awareness of the issues associated with moving personnel from one area of the Province to another in support of local activities. While ***this was understood even before the amalgamation of Vancouver Island in 2006****, these events have increased awareness of the issues and introduced an increased sense of priority to developing a common set of lock protocols. This has been further increased by the recent amalgamation of the Distribution and Transmission groups into a single Operations department."* [Ref: B-9, BCUC IR 1.52.2] [Emphasis added]

It appears the access control issue was understood but not acted upon when Terasen was under PBR in the period of 2006 through 2009. Further, this was not acted upon in 2010 and appears to not be in process for correction in 2011.

"The Communications and Public Affairs Plan … An expense of $44,465 was incurred in 2010 to complete the plan and a further $544,000 was reallocated to aspects of implementing the plan, representing most of the reallocation referred to in the referenced paragraph. Funding was made possible by savings associated with headcount vacancies across the organization and lower than forecast bad debt amounts." [Ref: B-9, BCUC IR 1.63.1, p. 189]

19.3 Please confirm this requirement for access control was ranked a lower priority within the FEU budget/cost process than the Communications and Public Affairs Plan in 2010.

Response:

As discussed in the response to BCUC IR 2.19.2, there have been no incidents affecting the risk to the natural gas delivery system associated with the unauthorized use of keys and the requirement for access control was less specific than will be required with the anticipated adoption of CSA Z246.1. The announcement of the intention to adopt the code requirement for increased access control was made in 2009 with comments invited up to December 2009. In 2010, it was not expected that the access control requirements detailed in CSA Z246.1 would be in place in that year and a program to meet the pending access control requirement was not in development. Consequently, it was not specifically compared to the Communications and Public Affairs Plan (the "Communications Plan") in terms of its priority and an investment was made toward the development of a comprehensive Communications Plan, and the various communication activities that document summarizes.

The Communication Plan represents a comprehensive strategic overview of the Companies' messaging needs for 2010 and 2011. The document logically summarizes important messages by intended audience and it maps out how best to deliver each message. In contrast, the FEU have typically approached communication requirements on a project-by-project basis, or upon the specific request of an internal department. The Communications Plan represents an effort to organize and prioritize the Companies' many messages and communication activities to meet customer needs and business goals.

20.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.54.1, p. 166; Exhibit B-6, BCOAPO IR 1.8.3

Leak Repairs

"The leak repairs were included in the 2010-2011 FEI (then TGI) RRA under "corrective maintenance" page 362 of the 2010-2011 RRA dated June 15, 2009. The additional funding required in 2012-2013 reflects the higher costs experienced in leak repairs in 2009 and 2010. Unit costs have a high degree of variability between $1000 and $200,000 depending on the complexity of the leak and the repair. The 2012 funding request reflects recent historical experience and the 2013 increment reflects inflation to the 2012 request." (Exhibit B-9, p. 166)

"The increased number of Leaks per Kilometer of Distribution System Mains in 2010 reflect a change in process for reporting and correcting leaks. Commencing in 2006, with the implementation of new processes as part of the Order Fulfillment Project, leaks were to be reported by creating an SAP internal document (i.e. Notification). However, it was discovered in 2009 that in many cases Work Orders were being raised to correct the leak without a corresponding notification. The statistics for reporting Leaks per Kilometer of Distribution System Mains were based on Notifications raised; due to the failure to consistently raise a Notification for a leak repair, the number of leaks during the 2006 to 2009 period are understated." (Exhibit B-6, p. 22)

20.1 Is the increase in leak repairs in 2009 and 2010 due to actual increases in the number of leaks or to changes in the reporting system that reduced the under reporting of leaks?

<u>Response:</u>

The increase in the SQI for leak repairs was due to a change in the reporting process. However, FEI's internal processes have correctly recorded the leak repairs as described in the following paragraph. FEI has experienced an increase in leak expenditures, even though the actual number of leak repairs has decreased slightly. This trend is further described below.

The FEU internal budgeting processes have correctly tracked the number of units of activity and associated leak repair costs. The SQI leak metric, however, has been under-reporting the number of leaks on **mains**. The budget system captures a broader type of leak repair activity than the SQI leak metric in that it includes leak repairs on services while the SQI leak metric focuses only on leaks on mains, a smaller subset of the total leak repair quantity and a subset of the overall leak repair budget.

Average Leak Repair Cost:

The increase in leak repair expenditures in 2009 and 2010 as compared to 2008 was primarily the result of increases in the average cost to repair leaks. The average cost is derived from the total annual leak repair costs and the total number of leak repairs (on mains and services) completed in the year. Individual leak repair costs have a high degree of variability (between $1,000 and $200,000 depending on the nature of the leak and the complexity of the repair). Typically leaks found on mains require considerably more effort and expense to repair (range from $2,000 to $200,000) and impact many customers. The leak repairs on services are generally in the $1,500 to $2,000 per repair cost range and often involve only one customer.

In recent years, Distribution Apprentices were gradually added to the crew complement as a response to the demographic challenge. Distribution Apprentices are provided with on-the-job training which often includes leak repair activity particularly where mains are involved. The addition of a crew member has been a contributing factor to the higher trend in leak repair unit costs.

Number of Leak Repairs:

The total number of leak repairs (on mains and services) has decreased slightly during the past three years from 555 repairs in 2008 to 514 repairs in 2010; however, the mix between service and main leak repair types varied over this period. The number of service leaks has decreased approximately 7% per year over the past three years (2008 to 2010) while the number of main leaks has increased approximately 10% per year over the same period. Service leaks make up about 80% of the number of repairs but only 54% of repair costs. Service leaks can often be attended to by a single customer service technician while main leaks typically requires a construction crew, customer service technicians and external services (flagging, paving, etc.).

21.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.54.1, pp. 166-167

Exhibit B-1, section 5, p. 174

Distribution – Costs driven by activity or unit cost changes

"The Field Service Delivery budget is the largest component of the Distribution budget at $20.8 million. Incremental increases in O&M of $416 thousand in 2012 and $272 thousand in 2013 are required in the category of Service Standards and Reliability for field service delivery activities. The changes in budget requirements are caused by changes in activity levels and unit costs." [Ref: B-1, Section 5, p. 174]

The attachment for the response to BCUC IR 1.54.1 does not contain the historical information to explain the increases of $416,000 in 2012 and $272,000 in 2013 for the field service delivery activities of Mainland or the increases of $353,000 in 2012 and $72,000 in 2013 for Vancouver Island.

21.1 Please provide the historical detail from 2006 through 2011 for the increases in field service delivery activities.

Response:

Attachment 21.1 contains are two Excel files (Attachment 21.1a for FEI and Attachment 21.1b for FEVI) which provide the historical detail requested for 2006 through to 2013 for the Field Service Delivery Activities. The spreadsheets present the total budgets for Field Service Delivery activities including items in the Service Standards and Reliability category and any other category, and therefore do not tie to the $416,000 and $272,000 (Mainland) and $353,000 and $72,000 (Vancouver Island) increases mentioned in the preamble to the question.

The format of the spreadsheets is essentially a listing of all field service delivery cost centres, description of major category (i.e. leaks repairs), description of sub-category or Maintenance Activity Type ("MAT") (i.e. DP main, IP main, LP main, Services, etc.), forecast ("plan") dollars for 2011-2013, actual dollars for 2006-2010, activity count where applicable and unit cost where applicable for each line item. Several row sub-totals are used throughout to summarize the major cost centre groupings (i.e. preventive maintenance, corrective maintenance, operations, meter exchange, emergency management services, meter to cash residential, and meter to cash industrial).

The budget methodology used for Field Service Delivery cost centres is essentially activity based budgeting (i.e. number of forecast activities multiplied by the forecast unit cost equals forecast budget). Year over year changes to labour and vehicle charge-out rates are then flowed through to the forecast unit costs in the various cost centres where these types of resources are utilized.

In terms of the number of Field Service Delivery activities, there are 46 cost centres in FEI and a duplicate set in FEVI and within those cost centres there are approximately 110 budgeted MAT types. Within one of the more broadly defined MAT types (i.e. cost centre 2590, Operations General, MAT type "STN" for regulator stations), there is an additional level of detail with 11 sub-categories beneath the MAT type level.

Units of activity are forecast for each MAT type where possible either based on scheduled maintenance or historical levels or combinations thereof. Unit costs typically are based on the most recent year's historical experience or longer trends where data is more reliable.

A portion of the field services delivery cost centre request is related to inflation and accordingly included in the overall inflation dollars identified in Table 5.3-17 (Exhibit B-1 page 171) for FEI and Table 5.3-18 (Exhibit B-1 page 177) for FEVI. The 2011, 2012 and 2013 forecasts ("plan") included in this response for Field Service Delivery cost centres include IBEW labour and vehicle rate changes which include contractor and wage rate inflation, employee benefit and concession rate changes and vehicle rate changes.

"The battery upgrades for industrial meters and the station transition repairs are new budget items for 2012 and 2013 and have not been specifically budgeted in prior years." [Ref: B-9, BCUC IR 1.54.1]

21.2 Please confirm the battery upgrades for industrial meters and the station transition repairs are items that did not occur prior to 2012. If they did occur as cost items prior to 2012, please provide the historical costs, identify the budget where they were included, and identify in Exhibit B-1 where the reduction in that budget can be seen.

Response:

Confirmed.

Battery upgrades for industrial meters: Alkaline batteries in rotary meter micro-correctors are failing between 2 and 2.5 years. This frequently results in three visits to these large meters within the six-year seal life of the meter; two scheduled visits and one unscheduled visit. The solution to the shorter alkaline battery expected life is to replace the battery with a lithium battery pack with an expected life greater than the six-year seal life and henceforth have only two scheduled visits to the meter (one for scheduled inspection after three years and one for meter exchange after six years). The replacement program is expected to be completed over three years (approximately 1,300 units per year) and gradually result in a reduction in unscheduled industrial meter exchanges which are costly and inconvenient to FEI and customers. FEI currently has approximately 500 of these unscheduled industrial meter visits annually and has reduced this quantity to 450 and 400 in 2012 and 2013 respectively to reflect the start of this program. The most significant reduction in unscheduled visits will come in 2015 at the end of the three-year program.

Station transition repairs: $100,000 in new funding in 2012 and 2013. Station piping is prone to heavy corrosion where the pipe transitions from below to above ground. Coatings intended for below ground use tend to degrade when exposed to UV radiation and may disband from the pipe resulting in accelerated corrosion. Similarly, paints and coatings intended for above ground use do not stand up well to abrasion and moisture typically found below ground resulting in accelerated corrosion. It is virtually impossible to have a 100 percent transition of coating exactly at grade and typically the below grade coating extends to above grade. The Corrosion department is developing a new coating standard to address these high risk areas. Incremental funding is required to assess existing stations where corrosion of this type has been reported and to complete repairs as required. Without maintenance, repair and recoating the above ground/below ground transition piping presents a significant risk to pipeline integrity.

Station transition repairs have not previously been listed as a separate budget line item; however, costs associated with previous work of this nature may have been included in the overall station repairs budget and station upgrade and replacement capital budgets depending on the nature and extent of the work. The funding being requested is to establish a specific program to review and repair approximately 20 stations per year over and above any station transition issues resolved through upgrade, replacement or retirement of the station.

> *"The leak repairs were included in the 2010-2011 FEI (then TGI) RRA under "corrective maintenance" page 362 of the 2010-2011 RRA dated June 15, 2009. The additional funding required in 2012-2013 reflects the higher costs experienced in leak repairs in 2009 and 2010."* [Ref: B-9, BCUC IR 1.54.1]

21.3 Please explain why the leak repairs would be under "corrective maintenance" in the "Codes & Regulations cost driver" in the 2010-2011 RRA and under the "Service Standards & Reliability cost driver" in this Application.

Response:

Generally speaking, the "Codes and Regulations" cost driver (FEU RRA 2012-2013 page 150-152) was established to capture incremental funding requests related to new, existing and/or updated codes and regulations. The "Service Standards and Reliability" cost driver (referred to as "Service Enhancements" in the 2010-2011 FEI RRA) was identified to capture incremental funding requests which support the ongoing integrity of our systems and may include changes in activity levels and unit costs under existing codes and regulations.

In the 2010-2011 FEI RRA, incremental and decremental budget line items for Distribution field service delivery activities landed in both cost driver categories. In the 2012-2013 FEI RRA, the majority of Distribution field service delivery activities landed primarily in the Service Standards & Reliability cost driver category as the incremental and decremental budget line items were primarily a result of changes in activity and unit costs under existing codes and regulations.

The FEU's internal budget process and these cost driver categories were better defined in the 2012-2013 internal budget process and Codes and Regulations requests were required to be supported by specific references to changes in code. There are some grey areas as to which cost driver is most applicable for individual incremental budget line items as most of the incremental requests in field service delivery activities, such as leak repairs, are arguably required to meet industry codes and regulations.

The 2010-2011 RRA on page 362 shows an increase of $402,000 from 2009 to 2010, and a further increase of $139,000 from 2010 to 2011 for "corrective maintenance"; there is no detail for what is included in this category. The attachment for the response to BCUC IR 1.54.1 shows the cost of leak repairs increased by $261,000 from 2009 to 2010 and decreased by $223,000 from 2010 to 2011.

21.4 Please provide the detail for the cost items in the "corrective maintenance" from 2009 through 2013, and identify where the balance of these items can be seen in this Application, and the justification for the increase in 2012.

Response:

Attachment 21.4 contains a detailed functioning Excel file for the FEI Corrective Maintenance group of cost centres showing the detail from 2009 to 2013, including both Plan and Actual dollars as well as all types of budgeted repair activities, quantities and unit costs (where applicable) for each category.

The increase in the 2012 Forecast from the 2011 Plan is $309 thousand and is comprised mainly of the following major items:

1. Cost centre 2530 – station repairs - $103 thousand, of which station transition piping repairs is $100 thousand (reference page 175 of Exhibit B-1).
2. Cost centre 2535 – leak repairs - $111 thousand (reference page 175 of Exhibit B-1 and the response to BCUC IR 2.20.1).
3. Cost centre 2560 – bridge crossing repairs - $110 thousand (reference page 175 of Exhibit B-1).

21.5 Please discuss if corrective maintenance resulted due to cost cutting actions taken during the PBR period that ended in 2009?

Response:

The FEU have maintained compliance with Codes and Regulations during the PBR period. During the PBR period some low risk maintenance was deferred to the benefit of the customers and the shareholder with an acceptable increase in associated risk. Examples of corrective maintenance that has risen from low risk and could not be deferred further than 2010 included: painting aerial and bridge crossings, stations and other assets; maintenance of non-critical valves; right of way clearing; and station line heater overhauls.

Regular preventive maintenance is completed on gas system assets to ensure safe and reliable delivery of gas to customers. Many of the failure modes associated with the types of equipment and the operating conditions are random and cannot always be prevented by preventive maintenance. As a result, assets are designed to ensure they continue to operate even when a piece of equipment fails. Corrective maintenance is initiated when equipment fails and is identified as part of a regular preventive maintenance program.

As the gas distribution infrastructure grows and ages, failures are monitored closely to determine whether the optimal level of preventive maintenance is being completed (i.e. increases in corrective maintenance are analyzed to determine the root cause and whether an appropriate preventive measure is available). Adequate corrective maintenance resources, coupled with adequate preventive maintenance resources, are a critical aspect of asset management and the programs designed to maximize the service life of the assets.

The attachment for the response to BCUC IR 1.54.1 shows an increase of $38,000 in leak repair in 2013.

21.6 Please explain why no increase has been requested for 2013.

Response:

There is no increase in leak repair activities forecast for 2013 from 2012 requested levels. The $38,000 incremental amount is for 3 percent wage/vehicle/contractor inflation on the 2012 base funding ($1,258,000) for leak repairs. The incremental amount of $38,000 is included in the inflation cost driver (refer Table 5.3-17 page 171 in the Application).

"The bridge crossing repairs were included in the 2010-2011 FEI RRA under "bridge and aerial crossing repairs" page 362 (2010 column)." [Ref: B-9, BCUC IR 1.54.1]

21.7 Please explain why the bridge crossing repairs would be under "corrective maintenance" in the "Codes & Regulations cost driver" in the 2010-2011 RRA and under the "Service Standards & Reliability cost driver" in this Application.

Response:

Please refer to the response in BCUC IR 2.21.3.

"The valve inspections were included in the 2010/-2011 FEI RRA under "Operations" page 364." [Ref: B-9, BCUC IR 1.54.1]

The 2010-2011 RRA budget on page 364 shows an increase of $122,000 in 2010 and $54,000 in 2011 for "Operations." The attachment for the response to BCUC IR 1.54.1 shows the cost of valve inspections decreased by $382,000 in 2010 and decreased a further $137,000 in 2011.

21.8 Please explain where this cumulative $519,000 decrease from 2009 to 2011 for valve inspections can be seen in this Application.

Response:

The $519 thousand decrease from 2009 to 2011 is comparing 2011 forecast to 2009 actual expenditures and is explained further below. This Application addresses changes between the 2011 projection and the 2012 forecast, and then from the 2012 forecast to the 2013 forecast. The 2012 forecast is $199 thousand higher than the 2011 projection, and the 2013 forecast is a further $25 thousand higher than 2012. The methodology for determining the 2012 and 2013 forecast is described below.

The valve inspection budget is zero-based each year with the primary determinants being the number and type of valves being inspected and the average unit cost required to complete the inspections. The number and type of valves varies each year due to differing maintenance frequencies depending on type, location and use of each valve. The unit cost varies by location due to valve crew size, type and size of valve and nature of the inspection (i.e. simple traffic free locations versus more complex inspections in major intersections requiring some form of traffic control). The inspections themselves also vary considerably from a visual, turn and lubricate to a more extensive repair. Repairs will often be done at the time of the inspection if they are reasonably simple so as to avoid the travel time and a second visit to the location.

The 2012 and 2013 forecast is based on the number of scheduled valves to be inspected (including main, service and TP valve types) multiplied by the forecast 2012 and 2013 unit costs which in turn are based on the 2010 actual experience, adjusted to reflect 2012 and 2013 labour/vehicle charge-out rates including inflationary increases.

A summary of the FEI valve inspection Budget and Actual dollars for the 2007-2013 period is included in the table below:

Table BCUC IR 2.21.8 FEI -Valve Inspections - Actual vs. Plan 2007-2013

Year	Actual ($000s)	Plan ($000s)	Change in Plan ($000s)	Actual vs. Plan ($000s)
2013	n/a	709	25	n/a
2012	n/a	684	199	n/a
2011	n/a	485	88	n/a
2010	623	397	-8	226
2009	1004	405	104	599
2008	413	301	14	112
2007	377	287	8	90

The unusually high level of expenditure in 2009 ($1,004 thousand) was primarily due to completion of 2007/2008 scheduled work carried over into 2009 and the simultaneous introduction and on the job training of new employees in the valve inspection area as a result of retirements.

The 2010 unit cost experience was considered reflective of expected unit costs moving forward and accordingly was used as the basis for the 2012-2013 forecasts.

The attachment for the response to BCUC IR 1.54.1 shows an increase of $25,000 in valve inspections in 2013.

21.9 Please explain why no increase has been requested for 2013.

Response:

There is no increase in valve inspections activity forecast for 2013 from the 2012 forecast levels. The $25,000 increase in the valve inspection budget represents a unit cost increase of $1 per valve which is essentially inflation on the base 2012 budget of $684,000. The $25,000 inflation amount in the valve inspection cost centre is included in the $1.3 million inflation amount listed in Table 5.3-17 in Exhibit B-1 on page 171 in the 2013 row.

"The line locates activity was not referenced in the 2010-2011 FEI RRA and the incremental request in the 2012-2013 is driven primarily by the activity and unit cost experience in 2009 and 2010." [Ref: B-9, BCUC IR 1.54.1]

The attachment for the response to BCUC IR 1.54.1 shows the actual cost of line locates as $407,183 in 2009, the budget as $486,200 in 2012, and the requested increase for 2012 as $125,000.

21.10 Please confirm the increase for 2012 of $125,000, instead of $79,000, is due to the increase in the number of BC One Call tickets (request for gas location records).

Response:

The 2011 projection is $361,600 and the 2012 level of funding required is $486,200 for an increase of $124,600.

The 2012 forecast of $486,200 was determined based on 2010 experience. For FEI, the number of locates completed in 2010 was 2,547 at an average unit cost of $187 each (roughly two hours of fully loaded labour and vehicle charges per locate) for a total expenditure of $476,000. The 2012 forecast is for 2,600 units of activity and unit costs similar to 2010. The 2009 level of activity was 2,852 and the 2008 level of activity was 3,144 so the general trend for the number of locates has been downward.

The number of BC One Call tickets has been trending upwards largely due to increases in excavator awareness of "Call Before You Dig" messaging and other utility safety messaging. The increase in the number of BC One Call tickets has not translated into an increase in locate activity. Only about 4% of BC One Call tickets requested results in a physical line locate. Physical locates are provided only under special circumstances such as excavations in proximity to high pressure pipe, excavators unable to locate with hand shovel despite having gas records, and unclear gas records. Generally speaking, most large scale excavators and larger municipalities have their own contract locators or in house locators that can perform this type of work once they have the FEU gas service records obtained through BC One Call.

The increase in funding required is primarily related to the higher recent unit cost experience per locate which is due to the presence of larger infrastructure projects in the mix. Several of these projects are related to the federal economic action plan to sprinkle projects throughout the Province in an effort to stimulate the economic recovery. Locate completion times include travel time and range from one hour to one week per location. The longer duration locates usually involve major construction infrastructure projects (interchanges, arterial roadways, etc.) where work is being done in close proximity to the FEU's gas lines. In the Lower Mainland, locate work is primarily contracted out (unit costs are based on periodically tendered contracts) while in the Interior this work is completed by the FEI workforce. The FEU locate policy is an integral component in our objective to reduce and minimize third-party damages to gas assets.

"Gas odour calls were not an incremental budget item in 2010-2011; however, the experience of 2009 and 2010 has led us to request additional funding to reflect the recent historical cost experience. The 2012-2013 request is based on the 2010 actuals which is very similar to 2009 actuals." [Ref: B-9, BCUC IR 1.54.1]

The attachment for the response to BCUC IR 1.54.1 shows a decrease of $200,000 from 2010 to 2011 and an increase of $200,000 from 2011 to 2012.

21.11 Please explain further why an increase is being requested for 2012 when "The 2012-2013 request is based on the 2010 actuals which is very similar to 2009 actuals", and the decrease in 2011 does not appear to be reflected in this Application.

Response:

The following table summarizes budget and actuals for FEI gas odour calls for the 2007-2013 period, showing that the 2012 forecast is equal to the 2010 actuals, as described above. The 2012 forecast is approximately $200 thousand higher than the 2011 forecast, reflecting the fact that 2012 expenditures are planned to be more in line with 2010 actuals than 2011 forecast.

Table BCUC IR 2.21.11 FEI -Gas Odour Calls - Actual vs. Plan 2007-2013

Year	Actual ($000s)	Plan ($000s)	Change in Plan ($000s)	Actual vs. Plan ($000s)
2013	n/a	2150	63	n/a
2012	n/a	2087	199	n/a
2011	n/a	1888	6	n/a
2010	2087	1882	111	205
2009	2035	1771	-47	264
2008	1896	1818	368	78
2007	1847	1450	8	397

The 2011 Plan (budget) is $1,888 thousand, slightly higher than the 2009 and 2010 plan; however, actual cost experience in 2009 and 2010 was $2,087 thousand and $2,035 thousand respectively, an average of $234 thousand over budget in the two years. The increase of $200 thousand in 2012 is required to provide funding for existing resources to respond to gas odour calls. The 2010 actual volume of activity (21,058) and average unit costs ($99) were used as the basis to forecast the 2012 and 2013 requirement. The 2010 volumes and unit costs were very similar to the 2009 volumes and unit costs.

The gas odour call budget is established each year based on the forecast number of calls multiplied by the forecast average unit cost. The average unit cost, based on previous year's actual experience, is driven by labour/vehicle charge-out rates which are mostly inflationary changes (including benefits).

We consider the 2009 and 2010 level of activity and unit cost experience to be reliable and consistent indicators of the volume and unit cost (adjusted for inflation) of the gas odour call requirement going forward.

The attachment for the response to BCUC IR 1.54.1 shows an increase of $63,000 in gas odour expensed in 2013.

21.12 Please explain why no increase was requested for 2013.

Response:

There is no increase in gas odour call activities forecast for 2013 from 2012 levels. The increase of $63,000 in gas odour expense in 2013 is related entirely to the change in forecast unit cost from $99 to $102 per call. The change in unit cost is driven by the year-over-year change in the labour/vehicle charge-out rate which is primarily wage related inflation of approximately 3 percent.

The incremental $63,000 is a component of the $1.3 million inflation amount listed in Table 5.3-17 of Exhibit B-1 on page 171 under row 2013.

22.0 Reference: Cost of Service

Exhibit B-1, BCUC IR 1.55.1, pp. 168-170

Distribution – System Sustainment Assessments

"Distribution has six staff currently performing system sustainment assessments as described below. Additional resources and O&M are required to conduct more detailed system sustainment reviews as part of the Long Term Sustainment Plan ("LTSP")." [Ref: B-9, BCUC IR 1.55.1]

22.1 Please explain the skill set required for the requested positions, and provide the number of employees at FEU that have this skill set.

Response:

The move to a longer term view of asset management is relatively new to the natural gas distribution industry and the skill sets required to support this move are evolving and will continue to develop as the requirements become better understood. To illustrate the type of skill set required to support the development of the longer term view of asset management, the following is an excerpt from the job description that has been drafted for an Asset Sustainment Planning Manager, a key role in developing the LTSP:

Role Specific Knowledge, Skills and Abilities:

- Knowledge of determining risk, factors contributing to risk and quantifying those factors.
- Demonstrated ability to work effectively where no precedent exists and where objectives are understood in only general terms.
- Demonstrated ability to include non-typical factors when resolving problems (e.g. applying socio-economic factors to engineering issues).
- Knowledge of gas operations, company standards, procedures and regulatory requirements.
- Knowledge of life cycle costing analysis to support asset repair and replace decisions
- Knowledge of project management.
- Knowledge of principles of operating transmission and distribution system assets.

- Demonstrated ability to communicate effectively both verbally and in writing.
- Demonstrated ability to work independently and as a member of a team. Demonstrated ability to apply analytical and logical approaches in the investigation and resolution of problems.
- Demonstrated ability to establish and maintain effective working relationships.

Subordinate role descriptions have yet to be developed. Because the concept of long term asset management is still developing, no person at FEU is expected to currently have all the skills and knowledge required to develop and implement the processes required to support the longer term view of asset management. It is estimated, however, that there are a number (fewer than ten) of personnel at FEU who currently have the combination of skills, experience and aptitude that will allow them to grow into the requirements of these positions.

23.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.56.1, p. 171

Distribution – Vehicle and Other non-labour inflation

"The vehicle and other non-labour (materials, contractors) inflation in 2010 and 2011 was $322 thousand and $309 thousand respectively but was not identified as a separate line item in those years. Non-labour inflation was included in the items listed on pages 362 and 364 of the 2010-2011 FE RRA." [Ref: B-9, BCUC IR 1.56.1]

This is another example of costs being defined as "Codes & Regulations" in 2010-2011 and "Service Standards & Reliability" in 2012-213.

23.1 Please explain what other shifts have occurred in the presentation of budgets by cost driver from the 2010-2011 RRA to this Application, and why the characterization of the costs has changed.

Response:

As described in response to BCOAPO IR 1.3.1, the cost driver categories as described in this Application are the same as in the 2010-2011 RRA. The FEU have been consistent between the categorization of costs by cost driver in the 2010-2011 RRA and this Application. Cost driver categories tend to be fairly stable over a period of time, but the specific items that result in changes to the costs within the categories will change from year to year. However, costs of the same nature in two different applications may result from a different driver, as more fully explained in the response to BCUC IR 2.21.3 and also in the cost driver descriptions below.

Each of the cost drivers is explained in more detail below:

1. Labour Inflation and Benefits – this category includes changes in labour and benefit costs relating to the existing employee base at the start of the forecast period.

2. Codes and Regulations – this category includes O&M resulting from new and changing codes and regulations. Once those changes have been implemented, ongoing funding levels to support those codes and regulations move to the Service Standards and Reliability cost driver in subsequent revenue requirement applications.

3. Customer and Stakeholder Expectations – this category includes O&M changes resulting from specific programs or projects undertaken by the FEU in response to new and changing needs of customers and other stakeholders.. Similar to the Codes and Regulations cost driver, after a change in customer and stakeholder expectations, O&M

will be considered funding to support ongoing customer or stakeholder expectations in subsequent revenue requirement applications.

4. Demographics – this category includes O&M changes resulting from the FEU's aging workforce (recruiting, training and developing). Items are consistently categorized in this category if they are due to changing demographics in the forecast period.

5. Service Standards and Reliability – this category includes non labour inflation and also incremental funding to support continuing business initiatives and system safety and integrity.

24.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.57.1, p. 172-177

Transmission – Asset Management / Assessments

"The FEU have interpreted BCUC IR 1.57.1 as a request for further details to better understand the Long Term Sustainment Plan (LTSP))". [Ref: B-9, BCUC IR 1.57.1]

The interpretation is incorrect. The question was to gather information on the overlap with existing processes which perform similar or related work.

The detail provided on the total resources for the Long Term Sustainment Plan (LTSP) is useful.

24.1 Please compare and contrast the work under the LTSP and the work on the LTRP (referenced in BCUC IR 1.68.0). Please provide the types of long range information that would be created/reviewed under both programs.

Response:

There is no overlap with existing processes performing similar work with regard to the Long Term Resource Plan and the Long Term Sustainment Plan. Rather, the two planning processes support one another. The LTRP is a higher level document and process with a much broader scope than the LTSP. While there are some common inputs into both planning processes, such as demand forecast information, this information is shared and not duplicated.

The LTSP is an expansion of existing asset management activities that helps to ensure adequate gas infrastructure to maintain safe, reliable, cost effective natural gas service to customers. This focus of the LTSP is driven by the aging of large portions of existing gas infrastructure, which face an increased rate of deterioration as they approach the end of their expected service life.

In contrast, the long term resource planning process involves a much broader review of market, policy and customer information. Customer and demand forecasts are prepared and EEC plans are examined as part of the long term resource planning process. The resulting demand information is shared with LTSP reviews as needed. New service initiatives in response to customer needs are also examined through the LTRP and only impact the LTSP when such new initiatives result in infrastructure additions that would be managed through the LTSP, after significant regulatory review and approvals for such new services.

In reference to BCUC IR 1.57.1, neither of the two people currently dedicated to the long term resource planning process, nor any of the new resources required as a result of the Commission directives from the 2010 LTRP decision, would be tasked with performing asset management activities. Where the LTSP identifies significant infrastructure requirements, the LTSP analysis will form an input into the Long Term Resource Plan. Again, the results of such analysis will be shared and not duplicated. In this way, some of the gas supply staff resources are drawn into the long term resource planning process and make up some of the other resources from across the FEU companies that are discussed in response to BCUC IR 1.68.2. The need for drawing these extended resources into the long term resource planning in this way will continue irrespective of the need for additional resources to satisfy the new Commission directives resulting from the 2010 LTRP decision.

None of the long range information described in Table 5.3-42 as presented in Exhibit B-1 and in response to BCUC IR 1.68.1, is currently developed, obtained or reviewed as part of either planning process. Going forward, any data or analysis completed for the LTRP as a result of Commission directives from the decision on the 2010 LTRP that might inform the LTSP will be shared between the two processes and will not be duplicated.

24.2 Please explain why the LTSP work is not an overlap of existing capital planning processes.

Response:

The LTSP work does not overlap the existing capital planning process but rather enhances the existing process so that a better understanding of longer-term future requirements is developed much earlier than is possible today. This understanding is essential in order to be able to proactively plan and prioritize future capital work. This improvement to the Companies' asset management practices is needed given the significant wave of asset renewal requirements that are expected to occur over the next 10 to 15 years.

The LTSP work extends the capital planning processes much further into the future with more detail and information than is currently available. This longer-term view of asset management involves the development of processes and methodologies to better determine asset health and to develop supporting maintenance strategies that optimize the useful life of gas system assets. This information will be used to develop and prioritize programs required to ensure ongoing asset reliability and the ability to safely and effectively meet customers' needs. This view of the future would also provide a communication tool to enable FEU to better inform stakeholders of future needs.

Future asset renewal projects and programs identified by the LTSP as necessary would be considered in the development of asset management budget requirements, both with a view to the longer-term future as well as the more immediate 1 to 5 year window. The 1 to 5 year window will typically provide the basis for developing budget and Revenue Requirements Applications with costs and requirements prioritized and planned in greater detail than would be typical in the 6 to 20 year window.

The significant increase in the future sustainment requirements is driven by the age of the Companies' gas system assets. In order to effectively manage these aging assets such that they continue to provide safe and reliable service, while minimizing the impact on customers' rates, requires much more detailed and longer-term asset management and renewal planning than what is possible today. The Companies are of the view that the asset management enhancements the LTSP brings will help to better manage the risks of ageing infrastructure, and enable a more efficient mobilization of capital, material, equipment, services, labour, and contractor resources for the orderly completion of asset replacements as they are required.

"Under current accounting guidelines these costs now need to be treated as an O&M expense." [Ref: B-9, BCUC IR 1.57.1, p. 175]

24.3 Please confirm if the reference to "current accounting guidelines" refers to IFRS or US GAAP, and if there is any difference in the treatment of costs related to capital projects.

Response:

Since the treatment of costs is consistent between Part V of the CICA Handbook, IFRS and US GAAP, the reference was intended to indicate that this treatment is required under all relevant current accounting guidelines.

24.4 How does this increase in O&M costs related to capital affect the 14% loading on capital projects?

Response:

All O&M expenses, including the incremental O&M expense attributable to the Long Term Sustainment Plan, are subject to a 14 percent overhead capitalization rate. As stated in the response to BCUC IR 1.72.2, this type of support falls within the capitalization criteria defined by the Capitalized Overhead Study filed as Appendix H to FEI's 2010-2011 RRA and independently reviewed by KPMG.

Findings presented in the above mentioned study supported an overhead capitalization rate of 8 percent. As part of the 2010-2011 RRA Negotiated Settlement Agreement, a 14 percent overhead capitalization rate was approved. Therefore, the costs identified above are subject to the approved overhead capitalization rate of 14 percent.

25.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.58.1, p. 178-179

Energy Supply & Resource Development – Asset Planning

"Resource Development … is also currently evaluating projects identified in the Companies' Long-Term Resource Plan." [Ref: B-9, BCUC IR 1.58.1, p. 178]

25.1 Please confirm the additional resources requested here are the same ones identified as "Resource Development" explained in BCUC IR 1.57.1 detailing the LTSP.

Response:

Not confirmed. The Resource Development resources identified in BCUC IR1.57.1 and 1.58.1 are not the same.

The resources identified in BCUC 1.57.1 represent an estimate of the resource commitment comprised of potentially a portion of all employees in the Resource Development department. The amount of time these employees will work on supporting the LTSP will vary over time, depending on the nature of the LTSP work requirements at the time and their availability.

The resources identified in BCUC 1.58.1 described two new hires that will work primarily on capacity/infrastructure projects, which for the most part are not expected to be LTSP related. These employees could, however, also complete work for the LTSP if required depending on the type of work that needs to be done and their availability.

26.0 Reference: ES & ER 2010 and 2011 Review - Mainland

Exhibit B-9, BCUC 1.61.1

Community Involvement

"Local Community Events and Other Program Sponsorships

These events and sponsorships include strategic business partnerships that engage customers, community opinion leaders and policy makers who have an impact on our business objectives.

These sponsorships are a fundamental element of our strategic communication plan and ongoing public consultation."

Community Involvement Spending

	FEI									
	2009		2010		2011		2012		2013	
	Actuals	Budget	Actuals	Budget	YTD May Actuals	Budget	Actuals	Budget	Actuals	Budget
Employee Give Where You Live Program Donations*	67,593	200,000	201,694	200,000	29,979	200,000		200,000		200,000
Community Investment Projects	60,000	60,000	63,320	60,000	60,500	60,000		60,000		60,000
Local Community Event and Program Sponsorships	242,674	166,000	262,119	166,000	43,710	166,000		170,000		177,000
	370,267	426,000	527,133	426,000	134,189	426,000	-	430,000	-	437,000

*Give Where You Live Programs moved to HR Department in 2010

	FEVI									
	2009		2010		2011		2012		2013	
	Actuals	Budget	Actuals	Budget	YTD May Actuals	Budget	Actuals	Budget	Actuals	Budget
Employee Give Where You Live Program Donations*	900		-		-					
Community Investment Projects	38,519	30,000	34,365	30,000	21,396	30,000		30,000		30,000
Local Community Event and Program Sponsorships	12,525	40,000	53,194	40,000	18,547	40,000		41,600		43,300
	51,944	70,000	87,559	70,000	39,943	70,000	-	71,600	-	73,300

26.1 For FEI, please explain why the actual Local Community Events and Other Program Sponsorships costs exceeded budgeted costs by $76,674 (or 46 percent) in 2009 and $96,119 (or 58 percent) in 2010.

Response:

This response also addresses BCUC IR 2.26.2.

The variances in the above table in 2009 and 2010 for Community Events and Program Sponsorships resulted from a combination of higher than expected cost pressures and an opportunity to redirect savings from other company cost areas to support Community Events. The portion of the variances attributable to each of these reasons has not been tracked in detail. Supporting our local government, association and community activities is a normal part of doing business in communities throughout the province. This type of support by the FEU for communities is expected by our customers as part of doing business, as evidenced in our regular customer service surveys and the significant number of requests for funding and support we receive annually from a variety of community service providers and business associations.

While the FEU manage the costs for individual community events and sponsorship investments, much of the variance in the total budget for Community Events and Program Sponsorships reflects the overall management of the costs throughout the Companies on an annual basis. In any given year the Companies will make some spending trade-offs as the business environment evolves relative to the environment that existed at the time the budgets were set one to two years prior. It is that evolution of the business environment that has caused the FEU to find minor savings in other parts of the organization to support these important community investments.

Causes of increased cost pressures in support of Community Events and Sponsorship include:

- One cost pressure stems from challenges to our business resulting from public policy. The Province's Energy Plan of 2007 and the 2010 *Clean Energy Act* both created challenges for the acceptance of natural gas as a fuel source by governments and communities across BC as a result of the focus on GHG reductions. In 2009 and 2010 additional efforts in community support aided in the effectiveness of communications with those communities to show that natural gas and other energy services provided by the FEU provide an important and foundational part of the solution to reducing carbon footprints and contributing to the Provincial Energy Plan.

- Another cost pressure is driven from the fact that over 30% of the FEU's operating agreements with municipalities across BC have come up for renewal in 2010 and 2011. Investment in community and local government events is an effective way to engage municipalities in discussions about the importance of our energy related activities in their communities, particularly for events that may bring multiple communities together in one location.

- A portion of the increased cost pressures were in support of the Union of BC Municipalities ("UBCM") activities such as the UBCM annual conference in November of each year. The ability to communicate the importance of natural gas and other energy service solutions the FEU can provide for community energy and GHG emission reduction challenges to a broader audience of municipal decision makers is an effective investment in community and government relations for the benefit of our customers. This increased presence and contribution to the conference agenda has been welcomed by the organization and the province-wide participants. This form of investment is more cost effective than duplicating similar efforts individually in the 135 communities that we serve.

- The economic downturn and the drawing away of other sources of community support as the 2010 Winter Olympic and Para Olympic games approached (that is other organizations that would normally provide greater community support diverted their support in order to weather the economic downturn or to be involved in the Olympics) are suspected reasons for the FEU being looked upon by communities to provide greater support to sustain community events, programs and sponsorships than we had in the past.

- The lack of significant progress towards resolving outstanding claims of First Nations has put greater expectations and pressure on business entities such as the FEU to provide capacity, training, employment, and education to First Nations, as well as develop and maintain close relationships with and to provide meaningful partnership opportunities to First Nations.

While some of these challenges remain for the FEU today, it remains to be seen what, if any, permanent increase in budgeting for Community Events and Sponsorships might be required. The FEU intend to continue monitoring these trends and bring any issues forward in any future RRA submissions as necessary. It should also be noted that these funding amounts are always in a certain amount of flux and experience some shifting priorities from year to year. It is therefore not possible to determine in detail the impact of any one of these pressures on the overall spending in this budget area.

The following tables provide a breakdown of the 2009 and 2010 Local Community Events and Sponsorship Program Costs as requested. Attachment 26.1 contains the tables in live spreadsheet format.

2009 FEI Local Community Events and Other Program Sponsorships costs:

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
28/09/2009	Vancouver	Sponsorship and participation at the UBCM Annual Conference	Elected Municipal Representatives from all BC Municipalities	Influencing local public policy, building relationships	80,362
29/01/2009	BC - all	Sponsorship of Trauma Pups for BC Fire Services	Fire Services / General Public	Building relationships with key partner and stakeholder group	17,248
13/01/2009	Prince George	Sponsorship of Chamber of Commerce Business Excellence Awards	Prince George Business Owners and Elected Officials	Building relationships with key stakeholders	3,500
13/01/2009	Prince Rupert	Sponsorship of BC Chamber of Commerce AGM & Conference	Organization that represents 35,000 small & medium businesses across BC	Public Policy advocacy	5,850
14/01/2009	Vancouver	Sponsorship of BC Chamber of Commerce Luncheon with Premier & Cabinet	Government Leadership	Public Policy advocacy	8,500
31/01/2009	Okanagan & Kootenays	Sponsorship of Environmental Mind Grind Program	Grade 4-12 student and Parents	Environmental Education and Awareness	12,000
30/01/2009	Nanaimo	Sponsorship of Annual LGMA Conference	Local Government Management Staff from across BC	Building relationships with key partner and stakeholder group	5,000
19/03/2009	Vancouver	Sponsorship of Employee Sun Run Team	Employee Volunteers	Bringing employees together for a local cause	1,777
5/03/2009	Kamloops	Sponsorship of Kamloops Indian Band Hockey Tournament	Kamloops Indian Band	Building relationships with Kamloops Indian Band	1,000
10/03/2009	Nanaimo	Sponsorship of LGMA Conference	Local Government Management Staff from across BC	Building relationships with key stakeholders	1,000
16/04/2009	Quesnel	Sponsorship of Family Fun Day in the Park in Quesnel	Quesnel Gas Customers	Community Involvement	400
29/04/2009	Maple Ridge	Community Environmental Initiative - Salmon Enhancement Program	ENGO, stream keepers	Community Involvement / Building relationships	3,000
24/06/2009	Osoyoos	Sponsorship of Southern Interior Local Government Association Conference	Elected Municipal Representatives from the Southern Interior	Building relationships with key stakeholders	2,500

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
25/06/2009	Vancouver	Sponsorship of BC Business Council Public Policy Conference Series	Business and government leaders	Public Policy advocacy	30,000
17/06/2009	Okanagan	Sponsorship of Okanagan Nation Alliance Annual Meeting	Okanagan Nation Alliance Leadership	Building relationships with ONA	5,000
1/06/2009	Victoria	Sponsorship of Former MLA's of BC Event	Elected Officials	Building relationships with key stakeholders	1,000
9/07/2009	Port Coquitlam	Community Environmental Initiative - Hyde Creek Salmon Festival	Elected Officials & General Public	Promote Environmental education and awareness	500
31/07/2009	Kelowna	Sponsorship of Solar Workshop	Local businesses	Promote awareness of solar technology and role of natural gas	2,763
31/07/2009	Kelowna	Sponsorship of Golf tournament supporting one of our largest commercial customers	Large commercial customers	Support for one of our largest commercial customers	2,500
31/07/2009	Kamloops	Sponsorship of Public Works Association of BC Annual Conference	Municipal Staff	Advocacy and Building relationships	1,000
28/08/2009	Kelowna	Sponsorship of BC Cancer Foundation Golf Tournament	Elected Officials and Business owners throughout the Okanagan	Building relationships with local politicians and business owners	1,225
27/08/2009	Kelowna	Sponsorship of Workshop on Conservation	Business owners and managers throughout the Okanagan	Community involvement and promoting conservation	1,000
28/09/2009	Southern Interior	Sponsorship of Okanagan Nation Alliance Annual Community Gathering	ONA members	Community Involvement	5,000
29/09/2009	Keremeos	Sponsorship of Local Community Project - Pit House Project	Lower Similkameen Band members	Community Involvement, Building relationships	10,000
29/09/2009	Kamloops	Sponsorship of Shuswap Nation's Annual Economic Growth Meeting	Shuswap Nation members	Building relationships, community involvement	2,500
3/09/2009	White Rock	Sponsorship of Chamber of Commerce Business Excellence Awards	Local government, businesses, and community stakeholders	Building relationships	450
2/09/2009	Kelowna	Sponsorship of Kelowna Museum Local Event	Kelowna General Public	Community Involvement	3,500

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
7/10/2009	Vancouver	Sponsorship of Annual Jack Webster Awards	Key stakeholders and opinion leaders	Building relationships	7,500
15/10/2009	Kelowna	Sponsorship of Heavy Metal Rocks Program	Grade 12 students from School District 23	Safety Education and Awareness	500
15/10/2009	Sea to Sky region	Community Environmental Initiative - Community Weed Pulls	Community volunteers along the sea to sky corridor	Community involvement, promoting community volunteerism	750
9/11/2009	Vancouver	Sponsorship of Canadian Council for Aboriginal Business Event	Aboriginal leaders throughout BC	Building relationships, community involvement	10,000
19/11/2009	Osoyoos	Sponsorship of Osoyoos Indian Band Youth Conference	Aboriginal leaders and youth throughout BC	Building relationships, community involvement	10,000
Miscellaneous	Greater Vancouver	Sponsorships (Miscellaneous, insignificant dollar amounts)	Community members	Community involvement	99
21/12/2009	Prince George	Community Environmental Enhancement Project	Prince George community	Building relationships, community involvement	1,000
18/12/2009	Victoria	Community Environmental Initiative - Support for Stream keeper training	ENGO, stream keepers and secondary students	Building relationships, community involvement	1,250
18/12/2009	Port Alberni	Community Environmental Initiative - Support for Urban Streams Restoration Program	ENGO, stream keepers	Building relationships, community involvement	1,500
29/12/2009	Penticton	Sponsorship of En'Okwin Centre	Aboriginal leaders in the Okanagan region	Building relationships, community involvement	1,500
Total FEI 2009 Local Community Event & Other Programs:					**242,674**

2010 FEI Local Community Events and Other Program Sponsorships costs:

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
27/09/2010	Whistler	Sponsorship and participation at UBCM Annual Conference 2010	Elected Municipal Representatives from all BC Municipalities	Influencing local public policy, building relationships	115,006

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
28/01/2010	Smithers	Sponsorship of Northern Communities Local Government Association Conference	Elected Municipal Representatives from Northern BC Communities	Building relationships	5,000
22/01/2010	Vancouver	Sponsorship of Aboriginal Tourism BC	First Nations businesses and leadership	Organizational capacity building, community involvement	50,000
28/01/2010	Barriere	Sponsorship of Southern Interior Local Government Association Annual Conference	Elected Municipal Representatives from Southern Interior	Building relationships	5,000
12/02/2010	Castlegar	Sponsorship of Association of Kootenay Boundary Local Government	Elected Municipal Representatives from Kootenay Boundary Region	Building relationships	5,000
3/02/2010	Grand Forks	Sponsorship of Grand Forks Solar Energy Forum	Local government and businesses	Advocacy - ensuring natural gas is part of the renewable energy mix	1,000
11/02/2010	Vancouver	Sponsorship of BC Chamber of Commerce Luncheon with Premier and Cabinet	BC Government leadership	Public policy advocacy, building relationships	4,250
18/02/2010	Ladysmith	Community Environmental Initiative - Salmon Enhancement Projects	ENGO - stream keepers	Community involvement, support volunteers	1,500
30/03/2010	Vancouver	Sponsorship of Vancouver Board of Trade Annual Governor's Banquet	Business leaders	Building relationships	5,000
30/03/2010	Prince George	Sponsorship of Business Excellence Awards	Local businesses	Building relationships, Corporate profile	3,500
10/03/2010	Port Coquitlam	Sponsorship of Volunteer Recognition Awards	Community stakeholders, opinion leaders	Building relationships, Corporate profile	5,000
5/03/2010	Vancouver	Sponsorship of BC Chamber of Commerce AGM & Conference	Organization that represents 35,000 small & medium businesses across BC	Public Policy advocacy	6,000
30/03/2010	Abbotsford	Sponsorship of SkillsBC Competition	Potential employees, community stakeholders	Corporate profile, Building relationships, Recruiting	1,333
26/04/2010	Langley	Sponsorship of Local Government Awareness Day	Local government, students, educators	Building relationships	1,200

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
19/04/2010	Kelowna	Sponsorship of Heavy Duty Rocks	Grade 12 Students School District 23	Safety Education and Awareness	500
7/04/2010	Vancouver	Sponsorship of Science World Gas Exhibit	General Public	Natural gas education and awareness	570
16/04/2010	Kelowna	Sponsorship of Kelowna Solar Conference	Community members	Promoting energy awareness	1,760
20/04/2010	Vancouver	Sponsorship of Employee team competing in Canstruction	Employees	Supporting Employee Volunteerism	10,000
21/05/2010	Kelowna	Sponsorship of Environmental Mind Grind	Grade K - 12 Students	Environmental Education and Awareness	12,000
3/05/2010	Vancouver	Sponsorship of Annual BC Chamber Executive Meeting	BC Chamber Executive, business leaders	Public policy advocacy, Building relationships	3,000
30/07/2010	Northern BC	Sponsorship of Northern BC Conference	Local government, stakeholders	Building relationships	500
13/08/2010	Vancouver Island	Community Environmental Initiative	Community members, ENGO	Community involvement, building relationships	1,500
30/08/2010	Elk Valley	Sponsorship of Heavy Duty Rocks	Grade 12 Students School District 5	Safety Education and Awareness	500
27/08/2010	Prince George	Sponsorship of BC River Day Music Festival	Community members, ENGO	Community involvement, building relationships	2,000
16/09/2010	Langley	Sponsorship of Water Week	General public	Environmental Education and Awareness	1,000
28/10/2010	White Rock	Sponsorship of White Rock State of the City Luncheon	Local Municipal and Government Officials	Building Relationships	1,000
26/11/2010	Whistler	Sponsorship of Local Government Management Association Banquet	Local Government Management Staff	Building Relationships	4,000
8/12/2010	Prince Rupert	Sponsorship of Northern Communities Local Government Association Conference	Elected Municipal Representatives from the Northern Region	Building Relationships	5,000
22/12/2010	Kimberley	Sponsorship of Association of Kootenay Boundary Local Government AGM	Elected Municipal Representatives from the Kootenay Boundary Region	Building Relationships	5,000

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
21/12/2010	Merritt	Sponsorship of Southern Interior Local Government Association Annual Conference	Elected Municipal Representatives from the Southern Interior	Building Relationships	5,000
Total FEI 2010 Local Community Event & Other Programs:					**262,119**

2009 FEVI Local Community Events and Other Program Sponsorships costs:

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
26/02/2009	Victoria	Sponsorship of Business Excellence Awards	Lower Vancouver Island Business Leaders	Building relationships, community involvement	2,625
24/06/2009	Whistler	Sponsorship of Canada Day Celebration	Whistler natural gas customers	Community involvement in support of Whistler Conversion project	5,000
27/11/2009	Whistler	Community event - Completion of Whistler conversion project	Elected Municipal and provincial government leaders and stakeholders in Whistler/Squamish region	Building relationships, Celebrating completion of Whistler Conversion project	2,900
28/04/2009	Ladysmith	Sponsorship of Arts on the Avenue	Mid Island gas customers	Community involvement in support of Mt Hayes Project	1,000
29/05/2009	Ladysmith	Sponsorship of Nanaimo Concert Orchestra	Mid Island gas customers	Community involvement in support of Mt Hayes Project	1,000
Total FEVI 2009 Local Community Event & Other Programs:					**12,525**

2010 FEVI Local Community Events and Other Program Sponsorships costs:

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
26/04/2010	Ladysmith	Sponsorship of Nanaimo Chamber Orchestra	Mid Island gas customers	Community involvement in support of Mt Hayes Project	1,000
29/06/2010	Nanaimo	Sponsorship of Chamber of Commerce Golf Tournament	Nanaimo small businesses	Customer relations	250

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
30/09/2010	Ladysmith	Sponsorship of Leadership Society of Vancouver Island	Mid Island gas customers	Community involvement in support of Mt Hayes Project	10,000
2/02/2010	Duncan	Sponsorship of Cowichan Minute Radio	Cowichan Tribes	Community involvement in support of Mt Hayes Project	4,500
3/02/2010	Vancouver Island	Sponsorship of Vancouver Island Economic Association	Vancouver Island businesses	Customer relations, community involvement	1,000
17/03/2010	Ladysmith	Sponsorship of Stz Uminus Cultural Dinner Festival	Stu'uminus First Nations	Community involvement in support of Mt Hayes Project	5,000
15/04/2010	Whistler	Sponsorship of the Local Government Management Association Annual Conference	Local Government Management Staff	Building Relationships	4,940
3/05/2010	Whistler	Sponsorship of Whistler Chamber of Commerce Service Recognition Awards Program	Whistler businesses	Community involvement, Building relationships in support of Whistler Conversion Project	3,500
15/06/2010	Victoria	Sponsorship of the Raise the Roof Initiative	General Public	Community involvement	500
16/08/2010	Fanny Bay	Community Environmental Initiative - Wilfred Creek Channel Protection	ENGOs, community members	Environmental Awareness, community involvement	2,000
20/08/2010	Ladysmith	Sponsorship of Arts on the Avenue	Mid Island gas customers	Community involvement in support of Mt Hayes Project	1,000
30/08/2010	Ladysmith	Sponsorship of Ladysmith Chamber Golf Tournament	Mid Island gas customers	Community involvement, Building relationships in support of Mt Hayes Project	2,000
29/09/2010	Vancouver Island	Sponsorship of "State of the Island" economic summit	Vancouver Island businesses	Building relationships	2,500
Miscellaneous	Vancouver Island	Sponsorships (Miscellaneous, insignificant dollar amounts)	Vancouver Island community members	Community involvement	444
28/10/2010	Victoria	Sponsorship of Royal Oak Golf Tournament	Elected Municipal representatives	Building relationships with key stakeholders	560

Date	Location	Event/Sponsorship	Target Group	Business Objective	Cost
29/11/2010	Victoria	Sponsorship of Community Living Victoria Fundraiser	Community members, customers	Community involvement	3,000
2/12/2010	Sidney	Sponsorship of AVICC Luncheon	Vancouver Island Local government officials	Building relationships with key stakeholders	5,000
21/12/2010	Nanaimo	Sponsorship of New Year's Eve Free Transit	General Public, Municipal government officials	Community involvement	6,000
Total FEVI 2010 Local Community Event & Other Programs					**53,194**

26.2 Please provide a breakdown of the FEI and FEVI 2009 and 2010 Local Community Events and Other Program Sponsorships costs by year using the format of the table below. Also provide the table in fully functional electronic format.

2009 FEI Local Community Events and Other Program Sponsorships costs

Date	Location	Event/ Sponsorship	Name of Target Group	Business Objective	Cost
Total Cost					

Response:

Please refer to the response to BCUC IR 2.26.1.

27.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.61.1 and BCUC IR 1.158.3;

Exhibit B-1, Part 4.4.4 p. 96

Community Involvement

"The rate of growth seen in our customer base reached a high in 2007 of roughly 12,000 customers but declined in 2008 and 2009. In 2010 account additions rebounded and the Company added just over 6,900 customers in the Mainland region." (Exhibit B-1, p. 96)

27.1 Given that the growth in FEI's customer additions appear to have leveled off, is the increase in actual Community Involvement spending from 2009 to 2010 primarily to grow the Thermal Energy Services line of business?

Response:

No. The increase in community involvement spending discussed in the response to BCUC IR 1.61.1 is not related to the FEU's thermal energy services, or the number of customer additions in a given year. Please see the response to BCUC IR 2.26.1, which provides an explanation of the increased cost pressures on our community involvement spending.

"**Terasen Gas Group 2010 Scorecard December 2010 Results**

		Results to Data	Target
FINANCIAL	1. Terasen Gas Group Net Earnings	$127.3m	$122.5m
CUSTOMER	2. O&M per Customer	$254.18	$255.64
	3. Base Capital	$98.9m	$111.8m
	4. Customer Survey Score	80.0%	80.0%
KEY PROCESSES	5. Credit & Collections	0.18%	0.35%
	6. Integrated Energy Service Offerings	1.0	Progress on new product development initiatives
			Challenge
EMPLOYEE	7. Recordable Vehicle Accidents	47	38
	8. Recordable Injuries	32	26
	9. Wellness	4.0	5.3
	10. Public Safety	*Service Quality Indicator*	

"

(Exhibit B-6, BCOAPO 1.7.2)

Table 2: O&M Costs for Travel, Training, Meals, Accommodation and Other Expenses Associated with the 12 Employees in the Thermal Energy Services Group (in $1000s).

Resource	2010 Actual	2011 Projected
Training	12	12
Travel	57	60
Meals	17	19
Mileage	16	18
Office Supplies	3	3
Membership dues	12	12
Sponsorships	**26**	**15**
Misc Admin	6	6
Advertising	49	50
Consulting & Services	176	105
Total Expenses	375	300

27.2 Given that "Integrated Energy Service Offerings" are a key process in the 2010 Balanced Scorecard please explain why only 6 percent of the 2010 Actual and 4 percent of the 2011 Projected Community Involvement spending is allocated to Thermal Energy Solutions.

Response:

The sponsorship costs shown in Table 2 as referenced in this information request are not part of the 2011 projected community involvement spending discussed in FEU's response to BCUC IR 1.61.1. Rather, these are costs for sponsorships related to the thermal energy class of FEU services. An example of the type of sponsorship costs included in Table 2 from this request are the Canadian District Energy Association sponsorship costs discussed in FEU's response to BCUC IRs 2.83.1 and 2.84.1.

Further, neither the sponsorship spending nor the community involvement spending can be considered in any way a measure of the importance of any of FEUs scorecard categories.

Finally, it should be noted that the 2010 scorecard measure "Integrated Energy Service Offerings" is explained as follows:

> The 2010 Scorecard result for this measure will be a subjective determination based on an assessment of the Company's success in obtaining approval of key service tariff offerings for biogas, NGV applications, developing new energy products, services and projects and also reaching customers on energy efficiency and conservation program such that funds available are fully subscribed by customers. We will also look to improve our end to end customer service experience enhancing our ability to deliver quality service to our customers.

As such, FEU's thermal energy services played a small role in the level of achievement met with regard to this scorecard measure, which encompasses much more than just thermal energy services.

28.0 Reference: ES & ER 2010 and 2011 Review - Mainland

Exhibit B-9, BCUC IR 1.61.2.1;

Retail Markets Downstream of the Utility Meter (RMDM) Guidelines, p. 8

Donations

"Ratepayers do not own a public utility's corporate name. The corporate name is goodwill which is owned by the company. The shareholders have a right to share in the assets of a company, including the corporate name, if the company is dissolved.[1]" (RMDM Guidelines, p. 8)

"The 2012 and 2013 donation and sponsorship costs are not shared equally between the ratepayers and the shareholder. The FEU consider donation and sponsorship costs to be a normal cost of doing business that are recoverable from customers consistent with past practice." (Exhibit B-9, BCUC 1.61.2.1)

28.1 Given that ratepayers do not own a public utility's corporate name and the corporate name is goodwill which is owned by the company, please explain why ratepayers should pay for donation and sponsorship costs that increase the value of the utility's corporate name and goodwill.

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. As the sponsorships and donations enhance the relationship between the utility and the communities it serves, in turn, it can affect the expenses associated with public consultation that are necessary as part of the utility's operation. The ratepayers are thus expected to fund the costs for such community investment programs that have a beneficial effect on their rates.

Moreover, donations and sponsorships are very much an obligation of a business enterprise to the communities it serves and are thus part of the cost of doing business.

28.2 Please provide the linkage between FEU's 2012-2013 donation and sponsorship programs and their key influences, key cost drivers and objectives in the Application.

Response:

The key influences and cost drivers of the FEU's community involvement spending are quite varied, ranging from community volunteerism of the FEU staff, to the types of influences and cost drivers discussed in the response to BCUC IR 2.26.1. In all cases, the objectives of these investments in the communities we serve and in which we operate include:

- create community partnerships that improve both our ability to work in these communities and the effectiveness of those activities;
- improve the pride that our employees take in working for the FEU and thus increase productivity and attract high quality employees;
- increase or maintain the pride and trust that our customers have in our business through knowing that we are actively engaged in the improvement of the communities they live in; and
- share information about the energy services we offer and activities we conduct in the communities we serve, which can include information about programs and safety.

Please also see the response to BCUC IR 2.28.1.

29.0 Reference: ES & ER 2010 and 2011 Review - Mainland

Exhibit B-9, BCUC IR 1.63.1

Practice Directive of the British Columbia Utilities Commission "Confidential

Filings" (Confidential Filings Directive), pp. 1-4

Confidential Response to BCUC IR 1.63.1

"The Communications and Public Affairs Plan is provided as Confidential Attachment 63.1. As this document discusses recommendations that leverage the FEU's strengths within the existing planning, operating and competitive energy marketplace, the FEU respectfully request that this document remain confidential." (Exhibit B-9, BCUC 1.63.1)

The Confidential Filing Directive states: *"If a party wishes to keep confidential any information in a document filed in a public hearing, the party must file a request that all or any part of the document be held in confidence and serve a copy of the request on the other parties."* (Confidential Filing Directive, p. 1)

29.1 In accordance Confidential Filing Directive, please file a request that all or any part of BCUC 1.63.1 be held in confidence and serve a copy of the request on the Interveners. The request, in accordance with the Confidential Filing Directive, FEU should clarify what harm would come from making these documents publicly available.

Response:

The FEU have reviewed the Communications Plan and agree to release it publically. The Communications Plan is included in Attachment 29.1.

29.2 Can FEU file a redacted copy of the confidential response to BCUC 1.63.1? If not, why not?

Response:

Please see the response to BCUC IR 2.29.1.

30.0 Reference: ES & ER 2010 and 2011 Review – Mainland

Exhibit B-1, Application, Part 5.3.8.3, p. 212

Exhibit B-9, BCUC 1.63.1

2010/2011 Communications and Public Affairs Plan

"A communications and public affairs plan was also made a priority for funding reallocation and continues to be implemented. As a result, there was an increase in spending of $680 thousand in 2010." (Exhibit B-1, p. 212)

"Funding was made possible by savings associated with headcount vacancies across the organization and lower than forecast bad debt amounts. At this time, there are no substantive funding reallocations currently planned for 2011, 2012 or 2013." (Exhibit B-9, BCUC 1.63.1)

30.1 Please provide a breakdown of the $680,000 savings used to fund the implementation of the communications and public affairs plan by year, cost centre and cost element. Also provide the FTE headcount vacancies across the organization by cost centre and year.

Response:

As noted in the response to BCUC IR 1.63.1, the Communications Plan cost $44,465 in 2010. No other funds were required to implement the Communications Plan since the Communications Plan simply summarized activities undertaken by ES&ER. The amounts identified in the Communications Plan represent recommendations, rather than firm commitments, and do not reflect actual expenditures made.

The relevant part of the Application referenced in this question is as follows:

"In 2010, the department had to manage more business activities than expected. Examples include greater than expected media coverage and public education about FEU's biomethane service offering, greater than expected social media activity, commodity rates education messaging, communications on natural gas solutions for transportation, an expanded event activity such as municipal conferences, industry events and builder association awards support. A communications and public affairs plan was also made a priority for funding reallocation and continues to be implemented. As a result, there was an increase in spending of $680 thousand in 2010."

The $680 thousand refers to the actual to budget variance for all of ES&ER in 2010.

It is not possible to identify the specific savings that permitted the additional expenditures in ES&ER. The FEU do not earmark specific savings to fund non-budgeted items like the incremental communication activities undertaken in 2010. The Companies pool known savings and then reallocate as appropriate. In general, the savings that provided the $680 thousand were associated with hiring delays, and a favourable bad debt account.

The requested department level analysis of the FEU headcount vacancies is provided in the response to BCUC IR 2.13.2.

30.2 Please provide a breakdown of the $680,000 for the implementation of the communications and public affairs plan by year, cost centre, activity and cost element.

Response:

As discussed in the response to BCUC IR 2.30.1, the cost of the Communications and Public Relations Plan (the "Communications Plan") was $44,465 in 2010. The $680 thousand referred to on page 212 of the Application (Exhibit B-1) is not specific to activities identified in the Communications Plan. Rather, the $680 thousand accounts for the actual to budget variance realized by the entire ES&ER department in 2010.

The primary drivers of the $680 thousand variance were contractor costs for communications development work and commercial energy studies. The Communications Plan sought to focus messaging and media strategies that were already anticipated. It did not drive a significant portion of the variance experienced.

31.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.65.1, pp. 193-194

Public Safety Education

"The number of instances of third-party damage to FEI's underground assets remains high across our service territory; furthermore, the lack of appropriate diligence being employed by excavating parties in BC continues to be a concern. Over 80 percent of the damage to FEI assets is caused by (a) parties failing to call BC One Call to determine the location of below ground assets and (b) hand-exposure of assets not being considered nor conducted. Improvements have been noted, but not to the level of significance that would indicate third parties have a firm understanding of regulatory requirements around excavation." [Ref: B-9, BCUC IR 1.65.1, pp. 193-194]

It appears that over 80 percent of the damage caused by third party construction activity related directly or indirectly to the BCOneCall program.

"Of the $750 thousand and $850 thousand in safety education spending referenced in each respective year, about 60 percent ($450 thousand and $510 thousand respectively) of this total amount will be spent on a separate program to educate the public about gas odour recognition and safe response awareness. Thirty percent (about $225 thousand in 2012 and $255 thousand in 2013) will be spent on excavation diligence messaging and the importance of safe digging practices."

31.1 Please explain if there is any empirical evidence of the cost of injury or damage to FEU plant related to lack of gas odour recognition and proper response.

Response:

The avoidance of injury or damage to the FEU plant/assets is critical; the minimization of hazards that can induce potential harm to workers and to the general public must be duly considered. The FEU are not aware of any empirical evidence or studies that correlate the cost of injury or damage to the FEU plant to lack of gas odour recognition and proper response, but believe that ongoing safety education awareness for all of our key messages including gas odour awareness and excavation diligence are extremely important in terms of improving public safety. The FEU are therefore addressing both injury and damage to the FEU plant and gas odour awareness and response with the required incremental funding.

Injury or Damage to FEU Plant:

Current and future educational programs will continue to strive for an enhanced understanding within the excavating contractor and homeowner communities. The FEU are already taking steps to reduce third-party damage and accidents through various damage prevention initiatives such as collaboration with the BC Common Ground Alliance, processing of BC One Call tickets and the educational activities undertaken by the Damage Prevention Department as mentioned in the Application (Exhibit B-1, Section 5.3.5.3). The FEU believe that additional support of these activities with additional public safety messaging is required, and have therefore allocated additional incremental funding support, which makes up 30% of the incremental communications budget for public safety and awareness.

Gas Odour Awareness and Response:

Gas odour recognition is not solely related to the protection of the FEU's equipment and plant, but is also about protecting the public from injury. The timely recognition and response to a gas odour will always serve to reduce the potential for injuries and damages.

The odourization of natural gas supports early notification around plant related concerns and is intended to act as a trigger for response by the general public. When the odour of natural gas is detected in a home, workplace or job site, people must recognize that there is a concern that they must respond to. Ensuring early detection and a speedy response to gas leaks remains the cornerstone of the corporate safety education strategy.

A number of incidents in the FEU service area, and other jurisdictions, have been provided herein, in order to demonstrate the critical nature of proper gas odour recognition and appropriate response by customers and other members of the public.

- A member of the public saw the FEU gas odour awareness advertisement in the Vernon Morning Star newspaper in February 2011. Although the woman did not have natural gas service at her home, she read the advertisement. Later that day, her daughter, who had natural gas service at her home in Kamloops, telephoned her mother and told her she could smell natural gas odour as she walked into her apartment. An email received by the FEU from this member of the public reads: "*there was a strong smell of gas and because of what I just read in the paper, I was able to tell her to get out and call the fire department, which she did - it probably saved her life and that of her son.*[7]" After a proper investigation, it was discovered that the tenants upstairs had left the gas stove burner on without a flame for an extended period of time; it took several hours for first

[7] Customer feedback, February 9, 2011

responders to make the area safe before residents were allowed back in their homes. In this case, lives were potentially saved because the gas odour was properly identified.

- In May, 2011, a member of the public was cycling through Central Vancouver and identified a gas odour. He notified the FEU and a crew was dispatched. After investigation, a previously damaged pipe was discovered as the cause of the leak. As the repairs were taking place, a customer whose house was located close to the damaged pipe told the investigators that she had noticed the gas odour prior to the cyclist's call, but did not call to report the odour as she was not aware of the potential concerns.

- On April 16, 1997, a natural gas explosion occurred in Quesnel. The hazard was due to ground shifting which had caused a natural gas line to break. The natural gas migrated underground and into a store located in a nearby plaza mall. Six people died and twenty more were injured in the explosion that resulted. The investigation demonstrated that residents and visitors who were in the area had smelled gas odour for several days prior to the explosion, but had failed to call the emergency line; some had thought that the smell was associated with the nearby pulp mill.

- On November 22, 2009, residents near an Encana natural gas well site reported smelling "sewer-like" odours and hearing a "jet-like" noise early in the morning. Although they noticed these conditions, none of the residents made any notification to Encana or emergency services. The odour and noise were caused by a natural gas infrastructure failure. As a result of a BC Oil and Gas Commission investigation, Encana was directed to improve public understanding of the safety information and proper response procedures. Encana was also required to develop a methodology for the assessment of the effectiveness of their public information program and to evaluate their program on an annual basis.

FEU responds to approximately 1,400 third-party damages and 20,000 gas odour calls annually. Each of these instances could be a potentially dangerous situation. Over a five-year period approximately 10% of the FEU's customers have called because they are aware that gas odour is a concern which requires an immediate response. The FEU strongly believe in the educational approach that will reinforce awareness of both natural gas odour recognition and the appropriate response required.

31.2 Please explain the allocation of 30% of the funding for third party construction related compared to the 80% impact on FEU plant by third parties.

Response:

The 30% of funding and 80% impact on the FEU plant referred to in this request are not correlated. The two statistics and the incremental funding allocation are further explained below.

The 30% relates to a portion of the incremental funding for public safety education that has been put forward in this RRA. 30% is the portion of the incremental funding that will be spent on educating the public about proper procedures involved with excavating in the potential vicinity of natural gas infrastructure. This safety education topic is one of the top priorities for the FEU's safety education programming because of the high percentage of infrastructure damage (this is the 80% reference from our response to BCUC IR 1.65.1) caused by improper excavation activities. However, this part of our safety education supports and is in addition to safety awareness activity being undertaken by the FEU's Operations group (who are conducting contractor safety training, for example) and safety education messaging by other organizations (primarily BC One Call). Since the number of damage incidents caused by improper excavation practices remains high (see Table 5.3-40 in Exhibit B-1) the spending in support of these other activities should be increased. The appropriate amount of increased funding needed to conduct this messaging is $225 thousand in 2012 and $255 thousand in 2013. This represents 30% of the overall incremental funding for safety education requested in this RRA.

A higher proportion (60%) of the incremental funding requested in this RRA for public safety education is being directed to another top priority topic (gas odour awareness and response) for which we are the only organization conducting safety education messaging within BC. While both of these topics are top priorities for safety education for the FEU, since the gas odour awareness and response messaging is more complex, current awareness levels are low and we are the only organization providing these messages, this topic requires more incremental funding for the RRA period than does the excavation diligence. The amount of incremental funding we are seeking for gas odour awareness and proper response education represents 60% of the overall incremental funding being sought for safety education.

32.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.68.1, pp. 198-209

Energy Solutions and External Relations – Long Term Resource

"Rather, an assessment of the amount of work required and the types of expertise needed has been completed. It has been determined that seven new FTEs are required to meet the expectations of the Commission and our stakeholders for our long-range planning activities." [Ref: B-9, BCUC IR 1.66.2, p. 196]

"The number and nature of staff resources from across the Companies that are involved with preparing various analysis for and synthesis of the LTRP always fluctuates to some degree depending on the issues that need to be addressed and the level of detailed analysis required for each issue." [Ref: B-9, BCUC IR 1.68.2, p. 208]

"In past Resource Plans, the number of staff who might provide input into the LTRP could range from approximately 30 to 40 staff members. For all of these resources the work completed on the LTRP makes up a small part of their regular activities and occurs for a temporary period during the resource planning process." [Ref: B-9, BCUC IR 1.68.2, p. 209]

32.1 Please sort the "Incremental Budget Item and Description" items from Table 5.3-41 in the response to BCUC IR 1.68.1 into the seven skill sets to match the seven proposed FTE.

Response:

This response also addresses BCUC IRs 2.32.2 and 2.32.5.

The additional staff resources required to address stakeholder feedback and meet the Commission directives contained in the Commission decision on the 2010 Long Term Resource Plan are primarily due to the amount of additional work load that these directives require and not, for the most part, because the necessary skill sets do not already exist somewhere within the FEU today. Existing staff and those being hired during 2011 under the current approved revenue requirements have been or are being hired to complete tasks that do not include those necessary to meet the referenced Commission directives. Further, these staff do not have the time capacity to undertake the required work irrespective of their skill sets. Therefore, new funding is required to perform this work.

While it is difficult to sort the budget items and descriptions into the specific skills sets of each individual resource the way that one might for a manufacturing process in a factory for example, the FEU offer the following additional detail about the required new resources. For some of the new positions, similar skill sets are required due to the extent of additional work to be undertaken, not because the Commission directives can be categorized into seven separate and distinct sets of skills that are readily available in the market place. The FEU need and envision the skill sets described in the following table, against which the incremental budget items from Table 5.3-41 are presented. Please note that more than one of these new staff resources could be working on a part of a particular budget item from the Table 5.3-41, and therefore, many of these items will appear next to more than one resource in the table below. In reality, the skills sets of the individuals hired to undertake this work will depend on the market place and may be somewhat different than the approximate skill sets presented in the second column of the table.

Additional Explanation for Incremental Staff Resources to Address Commission Directives from the 2010 LTRP Decision

Incremental Staff Resource	Approximate Skill Set	Incremental Budget Item from Table 5.3-41
Economic, market, policy and scenario analysis leader (I new position)	- economic policy analysis and forecasting - market impact analysis and forecasting - public policy analysis and forecasting - scenario analysis and resource planning - regulatory experience - statistical analysis - project management - report writing - presentations	- Staffing for increased economic research, analysis and reporting - Staffing for increased consideration of economic variables in developing future scenarios and considering impacts on energy use and resource needs - Staffing for energy use and GHG modelling, analysis and reporting - Funding for economic studies and reports, access to economic forums - Staffing for increased analysis of long term impacts of EEC scenarios on other resource requirements - Staffing to examine potential new service initiatives and analyze impacts - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale

Incremental Staff Resource	Approximate Skill Set	Incremental Budget Item from Table 5.3-41
Forecasting Analysis (2 new positions)	- Statistical analysis and modeling - Energy forecast modelling - End-use energy modelling - Energy choice analysis - Energy resource modelling - Industrial sector / customer segment / regional energy use analysis - Report writing - Presentations	- Staffing to develop new end-use forecasting methods, prepare and report on new forecasts - Staffing to compare new and traditional forecasting methods and processes - Staffing and funding to respond (within reason) to stakeholder requests and feedback during the long range planning process - Staffing for energy use and GHG modelling, analysis and reporting - Staffing for increased analysis of long term impacts of EEC scenarios on other resource requirements - Staffing to examine potential new service initiatives and analyze impacts - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale

Incremental Staff Resource	Approximate Skill Set	Incremental Budget Item from Table 5.3-41
Technology research and analysis, energy research and analysis (1.5 new positions)	- Energy equipment and appliance industry knowledge - Transportation equipment knowledge and experience - Codes and standards knowledge - Technology R&D industry knowledge and experience - Knowledge of policy and regulation affecting new energy equipment - Project Management - Report writing - Presentations	- Staffing and funding to respond (within reason) to stakeholder requests and feedback during the long range planning process - Staffing and activities associated with investigating non-EEC/infrastructure resource requirements - Staffing for increased analysis of long term impacts of EEC scenarios on other resource requirements - Funding for increased research into and review of technology advancements affecting energy use - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale
Market, policy, energy services, financial and emissions modelling (1.5 new positions)	- Customer impact modelling - Cost of service modelling - Market segmentation analysis - Air emissions modelling - Competitive analysis - Policy impact analysis - Report writing - Presentations	- Staffing and activities associated with investigating non-EEC/infrastructure resource requirements - Funding to support market access and transformation studies, reports and analysis - Staffing to examine potential new service initiatives and analyze impacts - Staffing to examine alternative legislative, regulatory and market future scenarios in regard to energy demand, EEC, new initiatives and other resources - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale - Staffing to investigate thermal and transportation energy demand on a regional and provincial scale

Incremental Staff Resource	Approximate Skill Set	Incremental Budget Item from Table 5.3-41
Stakeholder consultation lead and support analyst (1 new position)	- Project management and administrative skills - Communication and scheduling - Consultation expertise and experience - Analytical support	- Staffing for planning, preparing for and executing increased stakeholder activities - Funding to carry out increased stakeholder activities - Staffing and funding to respond (within reason) to stakeholder requests and feedback during the long range planning process - Staffing to examine potential new service initiatives and analyze impacts - Staffing to assist with other investigative and analysis activities - Staffing and funding support for communicating issues and analysis results and for including the increased long-range analysis and scenario considerations within the LTRP

32.2 Please identify the skill sets for each of the seven new FTEs that are required to meet the expectations of the Commission for the next LTRP, and identify the specific skill sets not currently within FEU.

Response:

Please see the response to BCUC IR 2.32.1.

32.3 Please identify the skill sets of the 30 to 40 staff members that provided input to the last LTRP and identify the missing skill sets required for the expectations of the Commission for the next LTRP.

Response:

The skill sets of the 30 to 40 staff members who provided input into the last LTRP range from administrative skills to energy forecasting analysis, to policy review, to infrastructure system planning, to regulatory advisory, to report writing and communications and more, through to director level oversight and senior management review. In general, the level of input from these existing staff members into the next LTRP is expected to stay approximately the same as it was for the last LTRP. This level of input, however, will not address the new requirements for the LTRP set out in the Commission's Order No. G-14-11 and Decision on the 2010 LTRP. Most, if not all, of the skill sets required for this additional work do exist within the FEU today; however, staff with these skill sets have other responsibilities and do not have the time capacity to undertake the additional work.

32.4 Please identify all employees hired since 2009, detail their skill sets, and confirm that none of them have skill sets which could contribute to the next LTRP.

Response:

The skill sets of the 251 full-time and part-time employees hired by the FEU since the end of 2009 range from distribution apprentices and other field personnel to technicians, technologists, as well as managers in customer service, energy efficiency and conservation, marketing and business development. It is possible that some of the new managers have the skill sets, and will be called upon, to contribute to the next LTRP. However, those individuals were hired specifically to fill other roles and responsibilities within the Companies and are not able to dedicate large amounts of time to the extensive new LTRP related activities that the FEU is directed to undertake. If those individual resources are redirected to work on the next LTRP, then new hires will be required to fill the roles left vacant by those individuals.

32.5 Please explain why new hires in 2011 would not have been selected so as to bolster the missing skill sets for work on the next LTRP.

Response:

Please see the response to BCUC IR 2.32.1.

33.0 Reference: Cost of Service

Exhibit B-1, BCUC IR 1.69.3, p. 211

O&M – Savings on US dollar exchange rate

BCUC IR 1.69.3 requested the US dollar saving across all of FEU, which is in addition to the savings referenced in 1.69.1 and 1.69.2 on just Information Technology.

33.1 Please provide the total US dollar denominated costs for the FEU in the total O&M spending for Actual 2010, Projected 2011, Proposed 2012 and Proposed 2013. Please provide the expected savings on this spending based on the current and latest forecast exchange rates. Please identify where this reduction can be seen in the Application, in addition to the materials in Sections 2.6 and 3.3 of Appendix G.

Response:

Outside of the US dollar denominated costs for Information Technology, which have been addressed in the responses to BCUC IR 1.69.1 and 1.69.2, the FEU estimate that the total US dollar denominated costs for the remainder of the organization, including capital expenditures as well as O&M but excluding gas costs, are less than $1 million annually from 2010 to 2013.

The FEU's total expenditures are allocated approximately 40% to capital and 60% to O&M.

Any savings resulting from US exchange attributed to capital will serve to reduce capital expenditures going into rate base. If the exchange rates quoted in BCUC IR 1.69.1 were applied to annual US dollar denominated capital expenditures of $400 thousand, the reduction in expenditures would be approximately $50 thousand in 2010 and $61 thousand in 2011. These reductions are spread across the capital expenditure categories in amounts too small to track or see in the changes reported in the Application, and due to the indirect impact of capital expenditures on the revenue requirements, would have no impact on rates.

If the exchange rates quoted in BCUC IR 1.69.1 were applied to annual US dollar denominated O&M of $600 thousand, the savings would be approximately $76 thousand in 2010 and $92 thousand in 2011. These savings in O&M are spread across the organization in amounts too small to track or see in the O&M changes reported in the Application.

As stated in the response to the BCUC IR 1.128.1, the FEU manage actual O&M in a manner that allows it to capitalize on "one-time" savings or opportunities so that "one-time" initiatives can be pursued. Therefore, the 2011 exchange rate savings have not been reflected in the 2011

Projection as they are expected to be used to address unusual or unforeseen items that may arise in the year.

34.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.70.1, pp. 212-213

Operations Engineering – CSA S250 Mapping Standard for Underground Utilities

"The new Draft CSA S250 Mapping Standard will add one extra step to the above described GIS process steps and it will also drive more rigorous requirements for the preparation and capture of GIS related information. First, the CSA S250 Mapping Standard introduces a new step in our GIS process that will require us to provide formal documentation to local governments. The standard dramatically increases the number of occasions where specific 'as builts' for simple construction jobs will need to be provided to local governments using strictly defined formats and criteria. Second, the CSA S250 Mapping Standard will drive more rigorous requirements such as the need to capture and map significantly more field information (i.e. sidewalks, driveways, traffic poles, hydro poles, trees, survey controls, etc.) to an increased degree of horizontal and vertical accuracy and include geographic coordinates for key features (i.e. valves, road boxes, etc.)." [Ref: B-9, BCUC IR 1.70.1]

34.1 Please explain if the CSA S250 Mapping Standard will work both ways, for example, is there a requirement only on FEU to capture, map and provide significantly more field information and provide it to local governments? Do the local provide updated information to FEU?

Response:

The CSA S250 Mapping Standard will work both ways with respect to the capture, mapping and sharing of information: all Owners[8] of utility infrastructure (a cable, line, pipe, or structure used to gather, store or convey products or services) will need to capture, map and share information about their assets to the same standard.

[8] CSA S250 defines Owner as the proprietor of the utility infrastructure including contractors, agents or other persons acting on behalf of the Owner.

35.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.71.1, pp. 214-215

Operations Engineering – B.C. Oil and Gas Activities Act (OGAA)

The response has been limited only to consultation relative to OGC permitted capital projects.

"Prior to OGAA coming into effect, communication activities in support of capital projects was not subject to regulatory compliance. For the 2012 and 2013 period, we are seeking additional resource funding to coordinate and manage new and existing consultation and notification communications processes to comply with the new regulations." [Ref: B-9, BCUC IR 1.71.1]

35.1 Please provide the total number of FTE within FEU that consult with First Nations, local government, organizations and land owners for any reason. Please provide the percentage of these FTE that perform their consultations for regulatory compliance.

Response:

The total number of FEU FTEs who consult with First Nations, local communities, organizations and land owners for any reason, fluctuates from year to year and month to month depending on the initiatives that are underway in a given time period. As shown in Figure 5.3-4 on page 208 of Exhibit B-1, the Community, Aboriginal and Government Relations Group includes 10 staff members who all participate in some way in consultation activities with these groups. Further, both the integrated long term resource planning and EEC functions include stakeholder consultation for which the number of staff involved varies from meeting to meeting depending on the topics being discussed. In any given year there may be special initiatives, such as the biomethane request for expressions of interest in 2009, for which consultation with these stakeholders is required and for which the FEU do not formally track staff involvement. Large capital projects such as the Mt. Hayes LNG storage facility also require consultation in which a range of the Companies' experts may be involved.

Only those staff identified in the response to BCUC IR 1.71.1 currently participate in consultation associated with OGC permit requirements as part of their regular duties. Existing staff available within the FEU do not have available workload capacity to take on the extent of additional work needed to meet the new OGAA requirements.

36.0 Reference: Revenue Requirement and Rates

Exhibit B-1, BCUC IR 1.76.1, pp. 223-224

Vancouver Island O&M Increase

The information in Table 1 in the response to BCUC IR 1.76.1 indicates the overall increase for FEVI is 19.9%, the increase for Customer Service is 176%, and the increase for Transmission is 106%.

36.1 Please explain if there is a reduction shown in another part of this Application which represents the previously charged costs from ABSU.

Response:

There is no offsetting reduction in FEVI for the incremental increase in the Shared Services fee from the FEI's Customer Service department. Under the ABSU contract ("the Contract") neither FEW nor FEVI were paying for any of the fixed expenses, instead all such costs were born by FEI customers. FEI was the first to contract with the ABSU, with FEVI and FEW becoming parties to the Contract at a later date. At the time of FEVI and FEW entering into the Contract, the capital assets and infrastructure (fixed costs) needed to provide this service were already in place to support the much larger FEI customer base. Therefore, FEVI and FEW were successful in negotiating a contract price that reflected only the incremental (variable) cost of serving their customers under the ABSU contract.

With the insourcing of the Customer Service function, an appropriate share of fixed costs is allocated to FEVI and FEW and is included in the increase in the Shared Services fee. Correspondingly, the cost for FEI customers will be reduced by the amount of the increase in the Shared Services fee recovery from FEVI and FEW.

36.2 Please confirm the increased charges from Transmission are for the Long Term Sustainment Plan.

Response:

Confirmed. Almost all of the increase ($118 thousand) is due to Long Term Sustainment Plan. The remaining $4 thousand is due to inflation on the base amount.

37.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.78.1, p. 226

Shared Services – Provision of services to Thermal Energy Services

"Please refer to Attachment 78.1 which shows the details of the overheads for TES."

37.1 Please explain, in addition to the material presented in table G-2 of Section 2.4.3 of Appendix G and the response to BCUC IR 1.78.1, why the overhead amount would not increase in 2012 when the direct charges are expected to increase by a factor of ten. Would not the work of the VP ES&ER, Accounts Payable, Operations Financial Analyst/Co-ord, and Project Management increase in proportion to the direct charges?

Response:

The original overhead allocation of $500,000 during the 2010- 2011 RRA period was not the subject of an overhead allocation study, but rather was a negotiated amount agreed to by all parties involved in the NSA as part of a settlement package. For this reason, developing an overhead allocation based on an escalation of the original amount is not appropriate. Instead, an internal allocation study was completed which showed that the actual allocation during 2010 and 2011 should have been less than $500,000 and that $500,000 is an appropriate amount for the 2012-2013 RRA period. The increase in project development activity that will be charged directly into the Thermal Energy Services Deferral Account has been taken into account for the 2012-2013 period. Overhead related activities will continue to be monitored by the FEU and if it appears that they will increase during future periods, the appropriate adjustments will be included in the forecast allocation for those years.

38.0 Reference: Property and Sundry Taxes

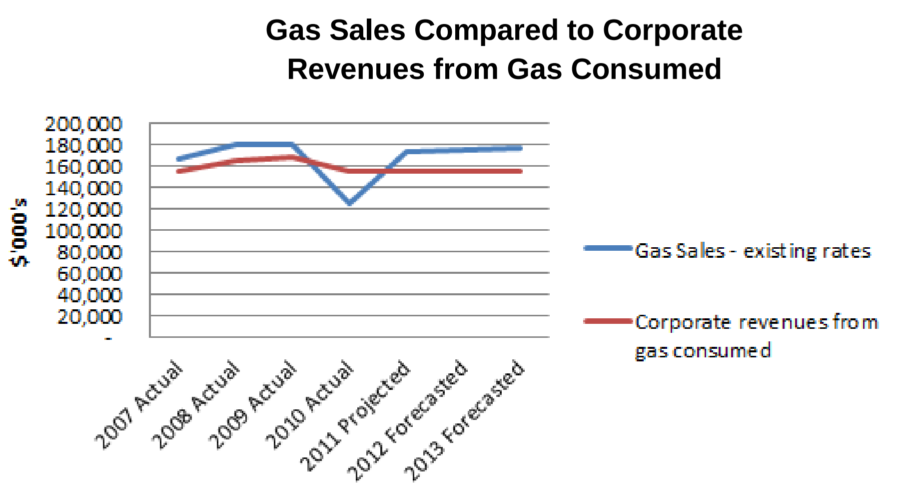
Exhibit B-9, BCUC IR 1.83.3, p. 249

Exhibit B-1, Application, Section 5.6.2, pp. 300-306; Section 7, Tab 7.2, Schedule 24-26

39.0 Details of Forecasted Property Taxes

39.1 Corporate Revenues from gas consumed for Vancouver Island does not appear to trend the same way as Gas Sales and Transportation Revenues at Existing Rates as per Schedules 4-6 and Appendix D-5, Historic Summary of Utility Income and Earned Return for Vancouver Island. In particular, corporate revenues from gas consumed shows a steady increase from 2009 to 2011 with a decline in 2012 and 2013, whilst the historic summaries and Schedules 4-6 for Vancouver Island shows a significant decrease from 2009 to 2010 and then a significant increase in 2011 and subsequently in 2012 and 2013, compared to 2010. Please explain whether these revenues should trend in a similar pattern and if they should trend in a similar pattern why the Corporate Revenues from gas consumed are not trending in the same direction as Gas Sales and Transportation Revenues at Existing Rates. If the assumptions and information presented are incorrect, please revise the table below with the appropriate information (i.e. assumptions made in *, ** and *** in the table below).

The information and graph below were prepared by Commission staff and illustrates the patterns described above:



	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Projected	2012 Forecasted	2013 Forecasted
Gas Sales and Transportation -existing rates**	189,321	202,159	204,559	148,883	172,676	195,091	214,087
Corporate Revenues from Gas Consumed*	155,170	164,270	168,360	154,890	154,890***	154,890***	154,890***

*Taken from row A from the table on p. 249 of the response to BCUC IR1.83.3

**2007-2009 information from Exhibit B-1, Appendix D-5 Historic Summaries and 2010-2013 information from Exhibit B-1, Tab 7.2, Schedules 4-6. This table also assumes that the 1% tax is based on gas sold and delivered.

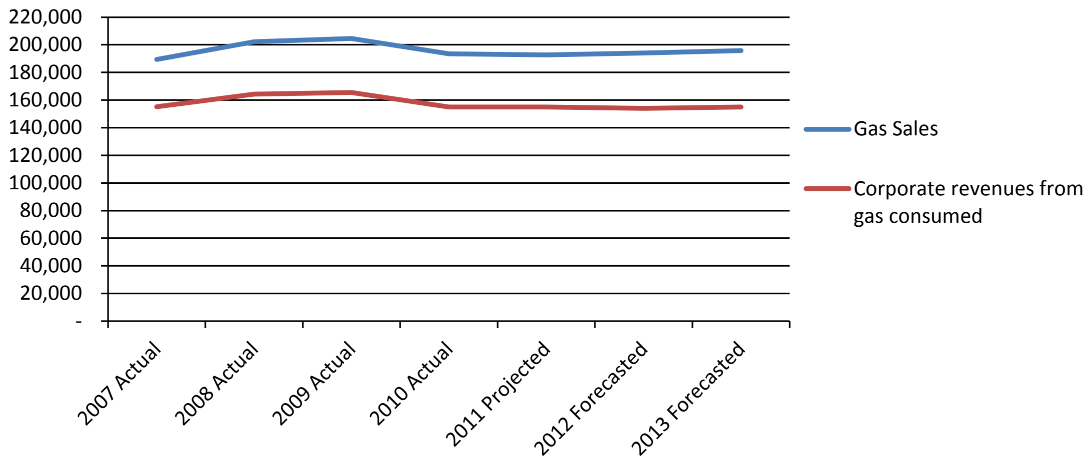
*** estimated to be equal to 2010 actual Corporate Revenues shown in row A of the Table on p. 249 of the response to BCUC IR1.83.3

Response:

Corporate Revenues from gas consumed for Vancouver Island for purposes of calculating property taxes will not necessarily trend in the same pattern or direction as Gas Sales and Transportation Revenues. The creation of new municipalities or extension of municipal boundaries may result in year over year increases in revenues reported to municipalities, since more revenues will now fall within municipal boundaries, while showing no change in total Gas Sales and Transportation Revenues.

The assumptions used to produce the graph and table in this question are incorrect. FEVI has provided a revised graph and table, with corresponding reference notes, below. In addition, FEVI notes that any variations in property taxes between forecast and actual (including variances resulting from differences in corporate revenues from gas consumed) will be captured in the RSDA in 2012 and 2013.

Revised Gas Sales Comparison to Corporate Revenues from Gas Consumed ($000)



	2007 Actual **	2008 Actual **	2009 Actual **	2010 Actual **	2011 Projected ***	2012 Forecasted ***	2013 Forecasted ***
Gas Sales and Transportation Revenues	189,321	202,159	204,559	193,410	192,629	194,132	195,727
Corporate Revenues from Gas consumed *	155,172	164,272	165,520	154,890	154,890****	154,089****	154,890****

* Row A from table on p. 249 of the response to BCUC IR1.83.3.

** 2006 to 2010 Gas Sales and Transportation Revenues- Appendix C, Tab 5, Vancouver Island, Utility Income and Earned Return, Actual Column, Line 11 + Line 13. Please note that the revenues must include the embedded revenue surplus of $44,527 in 2010.

*** 2011-2013 Gas Sales and Transportation Revenues: Section 7, Tab 7.2, Schedules 10-12, Line 24 Column 6 (for 2011) and Line 24 Column 5 (2012 and 2013).

**** Estimated to be equal to 2010 actual Corporate Revenues shown in row A of the Table on p. 249 of the response to BCUC IR 1.83.3.

40.0 Reference: Property and Sundry Taxes

Exhibit B-9, BCUC IR 1.83.4, pp. 253-254

FEI – Mainland: Property taxes – Revenue and Other Taxes

40.1 In the table presented, the amount shown in Row A1, Actual 2010, 2008 Corporate Revenues from gas consumed – all municipalities except Vancouver is $12.95 million. Please confirm that this amount should be $1,2950.00 million instead, and therefore the total shown in Row A3 should be $1,545.36 million and Row B-1 is correct at $12.94 million.

Response:

This response also addresses BCUC IRs 2.40.2 and 2.40.3.

The table provided in the response to BCUC IR 1.83.4 contained an error in Rows A1 and A2 and subsequently Row A3; however, the totals in Row B1 as reported in the response to BCUC IR 1.83.4 were correct. Please note these changes are errors in presentation and do not impact the property tax expense included in the cost of service. Below is a revised table with following changes highlighted in red:

- Row A1 for 2010 has been amended to $1,293.62 million
- Row A3 for 2010 has been amended to $1,543.98 million
- Row A3 for 2009 has been amended to $1,454.29 million
- Row A2 for 2012 and 2013 have been amended to $250.36 million
- Row A3 for 2012 and 2013 have been amended to $1,310.18 million

In millions	Actual 2009		Actual 2010		Approved 2011		Projected 2011		Forecast 2012		Forecast 2013	
A1: Corporate Revenues from gas consumed - All Municipalites except Vancovuer	2007	1,177.59	2008	1,293.62	2009	1,266.83	2009	1,203.70	2010	1,059.83	2011	1,059.83
A2: Corporate Revenues from gas consumed - Vancouver only	2008	276.70	2009	250.36	2010	271.86	2010	250.96	2011	250.36	2012	250.36
A3: Total Calculated Corporate Revenues from gas consumed (A1 + A2)		1,454.29		1,543.98		1,538.69		1,454.66		1,310.18		1,310.18
B1: Calculated Revenue Component of Property Tax - All Municipalities except Vancouver (A1 x 1.0%)		11.78		12.94		12.67		12.03		10.60		10.60
B2: Revenue Component of Property Tax - All Municipalities Vancouver Only (A2 x 1.25%)		3.46		3.13		3.40		3.14		3.13		3.13
B3: Calculated Revenue Component of Property Tax (B1 + B2)		15.23		16.07		16.07		15.17		13.73		13.73
C: Other Taxes (OGC Fees)		0.08		0.18		0.20		0.19		0.19		0.19
D: Total Calculated Revenue and Other Taxes		15.32		16.25		16.27		15.36		13.92		13.91
E: Corporate Revenue Component of Property Tax (in millions)		15.32		16.25		16.27		15.36		13.92		13.91
F: Difference (D-E)		-		-		-		-		-		-

40.2 The total in Row A3, Actual 2009, appears to be incorrect. Please confirm if the total should actually be $1,454.29 million.

Response:

Please refer to the response to BCUC IR 2.40.1.

40.3 Per notes on p. 254:

2. For 2012 estimates were based on the overall change in actual 2010 revenues when compared with 2009. The following factors were used in estimating 2012 Revenue component taxes:

Interior	-12.3%
Columbia	-7.6%
Lower Mainland	-12.1%
Vancouver	0.0%
Squamish	-5.0%

The factor applied to estimate 2012 revenues for Vancouver is 0.0%, however, per the table presented on p. 253, the forecasted 2012 revenues (and forecasted 2013 revenues) show an increase of $61.99 million from actual 2010 revenues. Please explain why such an increase and what it relates to when the factors used in the estimation of 2012 revenues is based on the overall change in actual 2010 revenues compared with 2009 or 0.2%.

Response:

Revenues for the City of Vancouver were overstated in the response to BCUC IR 1.83.4. Revenues should have been shown as $250.36 million, not $312.95 million, for both Forecast 2012 and Forecast 2013. Please note that this was an error in the presentation of the table only in the response to BCUC IR 1.83.4, and does not impact the forecast property tax included in the cost of service for 2012 and 2013. Please refer to the revised table provided in the response to BCUC IR 2.40.1, which reflects this correction.

40.4 Per notes on p. 254:

3. Other tax reflects the annual fee charged by the Oil & Gas Commission ("OGC") that was introduced in 2001. In 2010 the OGC changed its fee structure from $25 per km of transmission pipeline to $50 for pipeline under 152 mm and $60 for pipeline over 152 mm.

Please complete the following table for years prior to 2010 and explain any significant variances in 2007-2009 compared to 2010-2013 that do not appear to be a result of the OGC change in fee structure (post 2009 rates are approximately double the rates in place pre-2010):

In $000,000's	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast
Other taxes embedded in Line 5, Schedule 24-26				0.18	0.19	0.19	0.19

<u>Response:</u>

$ Millions	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast
Other taxes embedded in Line 5, Schedule 24-26	0.09	0.09	0.08	0.18	0.19	0.19	0.19

The increase in OGC fees in 2010-2013 as compared to 2007-2009 is a result of the OGC change in fee structure.

41.0 Reference: Capital Expenditures and Plant Additions for Capital Projects and CPCN’s

Exhibit B-9-1, Attachment 85.1, 085.1 Live Spreadsheet

2012-2013 Forecasted Expenditures – FEI Mainland

Exhibit B-1, Section 6.2.7.2 – Mainland CPCNs – Anticipated Projects, pp. 382-383

41.1 It would appear from the schedule that, for some of the projects, the sum of the expenditures previously approved and the expenditures that the FEI-Mainland is requesting for approval for 2012 and 2013, far exceed the actual expenditures incurred to date. FEI-Mainland projects are summarized as follows:

In $000’s	**2010 and 2011 Approved (A)**	**2012 and 2013 Forecasted (B)**	**Total (C)**	**2010 Actual (D)**	**2011 Projected (E)**	**Excess/ (Deficiency)* =(C)-(B)-(D)-(E)**
Gateway Project	17,183	13,250	30,433	-	(4,500)	12,683
Customer Care Enhancement	107,423	13,291	120,714	(25,936)	(24,952)	56,535
Fraser River Xing Seismic Upg	520	-	520	(8,875)	(14,717)	(23,072)
Kootenay River Xing	2,000	4,000	6,000	(1,085)	(5,627)	(4,712)
Okanagan Reinforcement Project	1,000	-	1,000	-	-	1,000
Huntingdon Bypass	12,200	-	12,200	-	-	12,200
Total	140,326	30,541	170,867	(35,896)	(49,796)	54,634

* Factors in forecasted expenditures for 2012 and 2013 and assumes the full amount will be incurred in those years.

Response:

The table prepared by Commission Staff, as referred to in the question, does not provide an accurate comparison between total actual or forecast expenditures and total approved expenditures for CPCN projects. The table is inaccurate because it does not account for approved and actual spending prior to 2010 as well as timing differences between 2010 and

2011 forecast spending and 2012 and 2013 forecast spending. The response to BCUC IR 1.85.1 was used as the basis for the table provided by Commission Staff; to align with the requested format in that question (reconciliation of capital spending and plant additions), the FEU included the 2010-2011 forecast spending in the approved column. As is the case in 2012 and 2013, this does not capture the total approved spending for each project; rather, it reflects the FEU's forecast spending for each year. Therefore, the table as prepared by Commission Staff should not be relied upon to measure over or under spending associated with CPCN projects.

The FEU is submitting Attachment 41.1 to replace the Commission Staff's table as a measure of CPCN project status. Attachment 41.1 shows the total approved costs per the respective BCUC order approving each CPCN, rather than forecast spending per the 2010-2011 RRA as was shown in BCUC IR 1.85.1. Attachment 41.1 also provides a continuity of each CPCN's actual and forecast project costs for 2010-2013 to reflect the status of each project as compared to the approved amount.

To be clear, the FEU are not requesting approval for CPCN related expenditures in this Application. Each CPCN is evaluated through a separate process and if approved, the additions are included and recovered through delivery rates when the CPCN is in-service.

The following table provides a summary of the current forecast total spending for FEI CPCN projects, comparing to the total approved spending for each project. This table demonstrates that FEI is not far exceeding approved spending as indicated in the question. The variance in the Fraser River Crossing Project spending, as shown in the table below, is discussed in response to BCUC IR 2.41.4.

FortisBC Energy Inc. - Mainland
CPCN CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.		BCUC Order # Reference	Approved	2010 Opening WIP (from detail tab)	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast	2010-2013 AUFDC (from detail tab)	Total Forecast	Variance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) = (4) + (5) + (6) + (7) + (8) + (9)	(11)
1	Special Projects - CPCN's										
2	Customer Care Enhancement	C-1-10	$ 66,470	$ -	$ 25,936	$ 24,252	$ 13,291	$ -	$ 2,991	$ 66,470	$ (0)
3	Fraser River Xing Seismic Upg	C-2-09	$ 29,751	$ 10,366	$ 8,875	$ 14,717	$ -	$ -	$ 2,322	$ 36,280	$ 6,529
4	Kootenay River Xing	C-9-10	$ 8,304	$ -	$ 1,085	$ 5,627	$ 1,223	$ -	$ 285	$ 8,220	$ (84)
5	Okanagan Reinforcement Project [1]		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Huntingdon Bypass [2]		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
7											$ -
8	Total CPCN's		$ 104,525	$ 10,366	$ 35,896	$ 44,596	$ 14,514	$ -	$ 5,598	$ 110,970	$ 6,445
9											
10	Gateway Project [3]			$ -	$ -	$ 4,500	$ 11,500	$ 1,750	$ -	$ 17,750	

[1] Okanagan Reinforcement Project is not yet approved and is included in this table solely for comparison to the table in this IR question

[2] Huntingdon Bypass Project is not yet approved and is included in this table solely for comparison to the table in this IR question

[3] Gateway Project is not a CPCN and is fully recoverable through CIAC. It is included in this table solely for comparison to the table in this IR question

41.2 Please explain why FEI-Mainland is requesting for approval for additional capital expenditures for the Gateway Project and the Customer Care Enhancement Project when currently there is an excess of approved expenditures over actual expenditures incurred to date and budgeted cost to complete the Customer Care Enhancement Project is estimated at $67,132,000 compared to total expenditures approved/awaiting approval of $120,714,000.

Response:

Please refer to the response to BCUC IR 2.41.1 and Attachment 2.41.1.

The Gateway Project does not have an approved amount under the CPCN guidelines and is fully recoverable from the Provincial Government through contributions in aid of construction. The variance in the amounts identified in the Application and the 2010-2011 RRA are more accurately described as timing differences. This is evident in Attachment 85.1 in response to BCUC IR 1.85.1 which shows $17.2 million as "approved" for 2010-2011 as compared to a forecast of actual spending of $4.5 million for that same time period, resulting in a difference of $12.7 million. When the $4.5 million in 2010-2011 is added to the 2012-2013 forecast shown in Attachment 85.1 of $13.3 million, the total forecast spending for the Gateway project is $17.8 million. Again, since the project is fully recoverable from the Provincial Government (capital expenditures are offset by contributions in aid of construction), no amounts are included in rate base in any years related to this project.

The Customer Care Enhancement ("CCE") Project was approved by Commission Order No. C-1-10; the FEU are not requesting approval for additional capital expenditures related to the CCE Project in this Application. The budgeted costs to complete this Project have been corrected to $66.470 million from the total provided in the response to BCUC IR 1.85.1. The previously budgeted amount of $67.132 million incorrectly included AFUDC relating to the O&M portion of the Project. The amount of $66.470 is the same as the approved and actual/forecasted costs shown in Attachment 41.1 in response to BCUC IR 2.41.1. As explained in the response to BCUC IR 2.41.1, the $120.714 million is not a valid calculation of the total expenditures.

41.3 Why have no expenditures been incurred to date for the Okanagan Reinforcement Project and Huntingdon Bypass?

Response:

As stated on pages 382 and 383 of Exhibit B-1, the Huntingdon Bypass and Okanagan Reinforcement Projects are anticipated projects for which the FEI has not yet filed a CPCN. FEI has not sought to recover any expenditures for these projects in rates as they have not yet been approved.

41.3.1 Huntingdon Bypass - Per commentary on p. 382 of Section 6.2.7.2 – Mainland CPCNs – Anticipated Projects in Exhibit B-1, FEU plans on submitting a CPCN application in the second quarter of 2011 for the installation of the station bypass and that the current project cost is estimated at $25-$30 million. Is this CPCN application and estimated $25-$30 million in project cost over and above the $12.2 million that was previously approved for 2010/2011?

Response:

No, the project costs of $25-$30 million would be inclusive of the $12.2 million in capital expenditures identified in the 2010-2011 RRA as an anticipated CPCN. Although $12.2 million in capital expenditures was identified in the 2010-2011 RRA, it was not approved as part of the 2010-2011 RRA or in a CPCN application, has not been included in rate base, and has not been recovered through customer rates.

The project remains in its development stage with several alternatives under consideration. FEI will seek approval for the recovery of Huntington Bypass costs in the CPCN application for that project. FEI now expects to submit a CPCN application in Q4 of 2011.

41.3.2 Okanagan Reinforcement Project - Per commentary on p. 383 of Section 6.2.7.2 – Mainland CPCNs – Anticipated Projects in Exhibit B-1, there are three significant resource options that the FEU is contemplating for a CPCN application to be submitted as early as 2014. How does the $1 million that was previously approved for 2010/2011 relate to these three options and the progress of this project?

Response:

As stated on page 383 of Exhibit B-1, the Okanagan Reinforcement Project is an anticipated project for which the FEI has not yet filed a CPCN. As such, the FEI has not yet sought to recover expenditures for this project in rates; and no amounts have been approved for recovery.

Although some costs for the Okanagan Reinforcement Project were included in the capital expenditures in Section C, Tab 13, Schedule 43 of the 2010-2011 RRA, they were not added to rate base or included in rates. Only $2,000 has been spent on this project to date, and that amount is included in work in progress and therefore not included in rate base in 2012 or 2013.

41.4 Per Tab 42.1 – FEI of Attachment 85.1 the Fraser River Xing Seismic Upg is overbudget by 22%. Please explain why the project is overbudget by such a large margin and whether the FEI-Mainland intends to recover the variance from rate payers?

Response:

This pipeline integrity Project involves two 1.4 kilometer horizontally directional drilled ("HDD") pipelines (20 and 24 inch) under the Fraser River. At this time the estimated cost at completion for the Project is $36.3 million including AFUDC based on completion of the associated restoration work in 2011 and excludes a settlement between the construction contractor and FEI in the event that the construction contractor submits and is determined to be compensated for any extra-ordinary claims. The Project will be included in rate base in October of 2011 based on the current timeline for the pipelines being put into service.

As has been described in FEI's quarterly Project progress reports to the Commission, the estimated cost at completion is now higher than the Project control budget of $29.75 million due to the following issues related to problems which the construction contractor and its HDD sub-contractors encountered during the execution of the Project: These issues have arisen due to factors beyond FEI's control as described below.

First, an unsuccessful 20 inch HDD attempt occurred in January 2010 which caused a 10 month delay in the Project. The HDD sub-contractor had a major failure of its equipment, and consequently abandoned the first 20 inch HDD attempt and ceased doing further HDD work. The construction contractor chose to terminate its agreement with its HDD sub-contractor and as a result replaced the first HDD sub-contractor. FEI believes the failed attempt to be to the account of the construction contractor under the FEI's guaranteed completion contract with the construction contractor. The FEI's incremental Project costs attributable to this ten month delay include additional geotechnical investigations and design of a new 20 inch HDD drill path, as well as Project management, Project inspection, and ongoing activity to ensure adherence to applicable technical and environmental codes and standards. The construction contractor's replacement HDD subcontractor subsequently successfully installed the 20 inch HDD pipeline under the Fraser River in August 2010.

Second, an additional delay of twelve months arose in July 2010 from an incomplete 24 inch HDD pull-back of 55 metres. During the 24 inch pull-back operation, the replacement HDD sub-contractor was unable to complete the last 55 metres of the pull-back into south side entry/exit casing which resulted in a separation of the reamer from the swivel. The replacement HDD sub-contractor was unable to reattach to the swivel. The subsequent tie in to the HDD section on the south side of the 24 inch pipeline has required the construction contractor to use an extensive deep excavation and dewatering system on the south side of the Fraser River in order to access the pipeline for inspection, welding and testing, and on the north side insertion of a steel sleeve between the casing and the 24 inch pipeline to provide long term integrity. FEI believes the incomplete 24 inch pullback to be to the account of the construction contractor under the FEI's guaranteed completion contract with the construction contractor. The FEI's incremental Project costs attributable to this further 12 month delay include re-designs, assessments of the construction contractor's methodologies, procurement of induction bends for the 24 inch pipeline for the south side tie-in, incremental project management costs and taking remedial steps to ensure satisfactory environmental compliance and corrosion protection of the 24 inch pipeline.

Third, the delays totalling 22 months have required FEI to extend agreements in place for land use and access. The FEI continues to keep landowners and local businesses informed as well as assess the potential for replacement of construction area materials in the site restoration process

FEI has been providing quarterly progress reports to the Commission on this Project in accordance with the CPCN granted by Commission Order No. C-2-09. FEI is including a copy of the latest quarterly progress report filed confidentially with the Commission on July 27, 2011. FEI is placing the report into the record of this proceeding on a confidential basis as Confidential Attachment 41.4. The need for confidentiality of the details of the quarterly progress report is that it includes financial information relevant to the contract with the construction contractor, and disclosure of this sensitive information on the public record may adversely impact the administration of the contract.

An Undertaking of Confidentiality, in accordance with the Practice Directive of the Commission on Confidential Filings, has been provided in non-confidential Attachment 41.4. FEI has no issue or concern with providing a copy of confidential Attachment 41.4 to registered parties in this proceeding upon receipt of an executed Undertaking of Confidentiality.

FEI believes that its Project management and contracting process has been appropriate including risk mitigation measures where the construction contractor bears a significant portion of the risks. FEI believes that all Project costs were prudently incurred and will result in long term used and useful assets for the lower mainland transmission system. FEI believes that it is appropriate to include the costs in rate base and recover from customers the expenditures for this pipeline integrity Project which is critical to the gas transmission system serving the FEI's lower mainland customers.

42.0 Reference: Capital Expenditures and Plant Additions for Capital Projects and CPCN's

Exhibit B-9-1, Attachment 85.1, 085.1 Live Spreadsheet

2012-2013 Forecasted Expenditures-FEVI

Exhibit B-1, Section 6.2.7.3 - Vancouver Island Approved Projects, p. 383

It would appear from the schedule that, for some of the projects, the sum of the expenditures previously approved and the expenditures that FEVI is requesting for approval for 2012 and 2013, far exceed the actual expenditures incurred to date. FEVI projects are summarized as follows:

In $000's	**2010 and 2011 Approved** **(A)**	**2012 and 2013 Forecasted** **(B)**	**Total** **(C)**	**2010 Actual** **(D)**	**2011 Projected** **(E)**	**Excess/(Deficiency)*** **=(C)-(B)-(D)-(E)**
Customer Care Enhancement	12,070	1,581	13,651	(2,801)	(3,170)	6,099
Mt Hayes LNG Facility	83,925	-	83,925	(49,439)	(31,436)	3,050
Victoria Regional Office	8,500	4,782	13,282	-	(8,456)	44
Total	104,495	6,363	110,858	(52,240)	(43,062)	9,193
In $000's	2010 and 2011 Approved	2012 and 2013 Forecasted	Total	2010 Actual	2011 Projected	Excess/(Deficiency)*
Customer Care Enhancement	12,070	1,581	13,651	(2,801)	(3,170)	6,099
Mt Hayes LNG Facility	83,925	-	83,925	(49,439)	(31,436)	3,050
Victoria Regional Office	8,500	4,782	13,282	-	(8,456)	44
Total	104,495	6,363	110,858	(52,240)	(43,062)	9,193

* Factors in forecasted expenditures for 2012 and 2013 and assumes the full amount will be incurred in those years.

42.1 Please confirm if the total approved expenditures for the Customer Care Enhancement Project is an allocation from FEI-Mainland's total approved and forecasted amounts for 2010-2013 of $120.7 million. If so, please confirm if

FEI-Mainland's total approved and forecasted amounts for 2010-2013 are shown on a net basis.

Response:

Please refer to the response to BCUC IR 2.41.1. The calculation of the excess/deficiency, in the table included in the question above, does not accurately reflect the status of actual/forecast capital spending against the total approved amount for CPCN projects. The reference to FEI-Mainland's total approved and forecasted CCE Project capital amounts for 2010-2013 of $120.7 million is incorrect.

The total project costs for CCE are currently forecast at $115.5 million. Total project costs include capital, deferred O&M and AFUDC. This forecast of $115.5 million is currently on track with the total project spending as approved by BCUC Order No. C-1-10 of $115.5 million (plus or minus 10% and including AFUDC). Of the forecast total CCE Project costs of $115.5 million, capital costs are approximately $74.5 million including AFUDC. As with the deferred O&M costs, the capital costs are allocated amongst the FEU based on average number of customers, with FEVI allocated approximately 10%. All capital amounts are on a gross (pre-tax) basis.

The following table provides a summary of the current forecast total capital spending for FEVI CPCN projects, comparing to the total approved capital spending for each project. This table demonstrates that FEVI is projecting capital spending to be at or below approved levels for all projects.

FortisBC Energy Inc. - Vancouver Island
CPCN CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.		BCUC Order # Reference	Approved	2010 Opening WIP (from detail tab)	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast	2010-2013 AUFDC (from detail tab)	Total Forecast	Variance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) = (4) + (5) + (6) + (7) + (8) + (9)	(11)
1	Special Projects - CPCN's										
2	Customer Care Enhancement	C-1-10	$ 7,851	$ -	$ 2,801	$ 3,170	$ 1,581	$ -	$ 299	$ 7,851	$ 0
3	Mt Hayes LNG Facility	C-9-07	$ 212,962	$ 117,750	$ 49,439	$ 31,436	$ -	$ -	$ 14,337	$ 212,962	$ -
4	Victoria Regional Office	C-1-11	$ 14,324	$ -	$ -	$ 8,456	$ 4,782	$ -	$ 884	$ 14,122	$ (202)
5											
6	Total CPCN's		$ 235,137	$ 117,750	$ 52,240	$ 43,062	$ 6,363	$ -	$ 15,520	$ 234,935	$ (202)

Please refer to the attachment to BCUC IR 2.41.1 for details of the correct approved and forecast capital amounts.

42.2 Per Exhibit B-1, Section 6.2.7.3, p. 383 the Mt Hayes LNG Facility project is expected to be completed in May 2011. What is the status of this project as at today's date? If so, it would appear that actual and projected expenditures would come in less than the amounts approved for 2010 and 2011. If an overall favourable variance is achieved, will the savings be passed on to rate payers?

Response:

As described in the Quarterly Reports provided to the Commission, the Mt. Hayes LNG Facility was placed into rate base on May 31, 2011 and the tank is in use for the upcoming winter season. Final project work continues on restoration outside the LNG Facility, warranty and deficiency items, and documentation of project information with the project expected to be completed by October 2011 and to be on budget.

A recent project cost analysis suggests that there is potential for the total project costs to come in approximately $1 million under budget. As this estimate was not available at the time of filing the Application or the July 19th Evidentiary Update, the FEVI has included budgeted costs equal to the approved CPCN amount within the financial schedules in the Application. Please refer to Attachment 41.1 in response to BCUC IR 2.41.1 (and the table provided in BCUC IR 2.42.1) which demonstrate that the total forecasted costs over the life of the project, currently embedded in rates, are equal to the CPCN approved amount.

If the overall project costs do end up being less than the approved CPCN amount, the savings in 2011, 2012 and 2013 will be captured in the RSDA. Furthermore, the plant in service and rate base will be reset in 2014 to include the actual costs of the project, rather than the forecast costs as included in this Application.

43.0 Reference: Capital Expenditures and Plant Additions for Capital Projects and CPCN's

Exhibit B-9-1, Attachment 85.1, 085.1 Live Spreadsheet

2012-2013 Forecasted Expenditures -FEW

It would appear from the schedule that, for the Customer Care Enhancement project, the sum of the expenditures previously approved and the expenditures that FEW is requesting for approval for 2012 and 2013, far exceed the actual expenditures incurred to date. The project is summarized as follows:

In $000's	2010 and 2011 Approved (A)	2012 and 2013 Forecasted (B)	Total (C)	2010 Actual (D)	2011 Projected (E)	Excess/(Deficiency)* =(C)-(B)-(D)-(E)
Customer Care Enhancement	964	44	1,008	(89)	(90)	785

* Factors in forecasted expenditures for 2012 and 2013 and assumes the full amount will be incurred in those years.

43.1 Please confirm if the total approved expenditures for the Customer Care Enhancement Project is an allocation from FEI-Mainland's total approved and forecasted amounts for 2010-2013 of $120.7 million. If so, please confirm if FEI-Mainland's total approved and forecasted amounts for 2010-2013 are shown on a net basis.

Response:

The total approved FEW expenditures for the Customer Care Enhancement Project are an allocation from the total approved expenditures for the FEU. The allocation of CCE project costs amongst the FEU is based on average number of customers, with FEW allocated approximately 1%. All amounts are shown on a gross (pre-tax) basis.

The reference to FEI-Mainland's total approved and forecast amounts for 2010-2013 of $120.7 million is not correct, nor is the calculation of the excess/(deficiency) in the table above. Please refer to the Attachment 41.1 provided in response to BCUC IR 2.41.1 for details of the correct approved and forecast amounts.

44.0 Reference: Gross Plant in Service

Exhibit B-9, BCUC IR 1.86.1

44.1 Please provide a table listing the variances, in %, between estimated and actual retirements, by year, for each FEI, FEVI, FEW from 2007-2011.

	2007	2008	2009	2010	2011
Total Depreciation forecasted in RRA					
Actual Depreciation recorded in Gross Plant in Service					
Total Losses (gains) forecasted in RRA					
Actual Losses/(Gains) recorded in RRA					

Response:

The FEU note that the question asked (referencing retirements) is inconsistent with the information requested in the table provided (referencing depreciation).

For information regarding estimated and actual retirements from 2007-2011 for each of FEI, FEVI and FEW, please refer to the response to BCUC IR 1.86.2.

For information as outlined in the table above, provided below is a table for each of FEI, FEVI, and FEW showing the variances between estimated and actual depreciation and losses/(gains) from 2007 – 2011.

As noted in the response to BCUC IR 2.44.7.1, for FEI during the PBR period from 2004 – 2009, the lower depreciation expense compared to forecast was primarily the result of approved capital expenditures being calculated on a formula basis, resulting in lower capital spending than approved and consequently a growing trend of lower depreciation expense than approved, with the savings shared between customers and the company.

FEI
(000s)

	2007	2008	2009	2010	2011
Total Depreciation forecasted in RRA	92,184	93,668	96,660	98,312	100,534
Actual Depreciation recorded in Gross Plant in Service	86,508	84,097	86,319	98,124	100,187
Variance ($)	5,676	9,571	10,341	188	347
Variance (%)	6%	10%	11%	0%	0%
Total Losses (gains) forecasted in RRA	-	-	-	-	-
Actual Losses/(gains) recorded in RRA	1,613	13,085	12,946	14,817	4,284

Notes:

1. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings
2. Depreciation forecasted for 2004-2009 was based on the PBR formula.
3. $100,187 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.

FEVI
(000s)

	2007	**2008**	**2009**	**2010**	**2011**
Total Depreciation forecasted in RRA	16,339	18,099	23,798	26,231	30,409
Actual Depreciation recorded in Gross Plant in Service	16,189	18,283	23,656	25,975	29,463
Variance ($)	151	(184)	142	256	946
Variance (%)	1%	-1%	1%	1%	3%
Total Losses (gains) forecasted in RRA	-	-	-	-	-
Actual Losses/(gains) recorded in RRA	666	849	649	660	727

Notes:

1. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings
1. $29,463 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.
2. Prior to 2009, forecast and actual depreciation was reported net of CIAC.

FEW
(000s)

	2007	2008	2009	2010	2011
Total Depreciation forecasted in RRA	-	-	501	387	394
Actual Depreciation recorded in Gross Plant in Service	513	500	516	353	366
Variance ($)	N/A	N/A	14	(33)	(28)
Variance (%)	N/A	N/A	-3%	9%	7%
Total Losses (gains) forecasted in RRA	-	-	-	-	-
Actual Losses/(gains) recorded in RRA	(47)	11	4,229	133	111

Notes:

2. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings.
3. Revenue Requirement was not filed for FEW in 2006, 2007, and 2008.
4. $366 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.
5. Losses in 2009 were due to the disposition of propane assets as a result of the conversion to natural gas. These losses were transferred to a rate base deferral account as approved by the Commission.

44.2 When FEU charges ratepayers depreciation against gross plant in service, is it fair to characterize this charge as a recovery of both depreciation and any net losses/gains on the retirements of gross plant in service?

Response:

FEU confirms that the proposed depreciation rates as filed include recovery of the decline in the service life of the assets and also any under/over recovery of depreciation (i.e. net losses/gains) from the retirements of assets for 2009 and prior. Starting in 2010, under/over recovery of depreciation for assets retired was captured in a deferral account. (The FEU are requesting that the amounts in the deferral account be recovered from customers over a 20 year amortization period.)

An excerpt is provided from the response to BCUC IR 1.136.2 outlining the development of the FEU's proposed depreciation rates.

> *"The FEU highlight that the development of depreciation rates for their assets follows what is common industry practice for utilities, where utility staff work with an external depreciation specialist to determine rates. This approach is preferred as it leverages the expertise of an external specialist who has industry-wide expertise and provides validation of the rates. In arriving at the recommended depreciation rates, the depreciation specialist performs a number of activities including a review of the FEU's assets and retirement transactions, conducting operational interviews with the FEU staff and comparing the results to the FEU's industry peers. In addition to providing the financial data requested by Gannett Fleming, the FEU review the recommended depreciation rates for accuracy, reasonableness and applicability to the assets.* ***The rates are then adjusted to factor in the recovery of any existing retirement losses that may be included in the accumulated depreciation account balance. The adjustment is designed to recover those losses over the remaining lives of the existing assets****."*

44.3 If FEU forecasted criticism at a level that was higher than actual depreciation, would the over-forecasted amount be applied against accumulated unrecorded losses on retirement?

Response:

The FEU interpret the above question to be "If FEU forecasted depreciation" instead of "If FEU forecasted criticism".

No, if actual depreciation expense is different than allowed (forecast in the test period), the difference does not get applied against the accumulated depreciation account. Only the actual depreciation expense will be recorded in accumulated depreciation. However, both over-recovered depreciation and under-recovered depreciation on retirement of assets resulting from differences in asset lives was applied against accumulated depreciation prior to 2010 in accordance with the Uniform System of Accounts.

While the majority of asset classes in the past have experienced net losses (i.e. under-recovered depreciation) from retirements, there have been a number of asset classes where net gains (i.e. over-recovered depreciation) have been realized. For example, as outlined in FEU's response to BCUC IR 1.117.3 requesting a summary of asset retirements for 2010 and 2011, gains were recorded for retirements in some asset classes in 2010.

44.4 When assets are retired in the year, is the total actual depreciation recorded on that asset group less than forecast depreciation? Is this answer different in the case of a gain or a loss?

Response:

FEU interprets the question 'When assets are retired in a year, is the total actual depreciation recorded on that asset group **for the year** less than forecast depreciation?' with "**for the year**" highlighted in bold for clarity.

In the situation described in the question, total depreciation recorded for the year may or may not be less than the forecast depreciation and is dependent on when the asset was forecast to be retired versus when it is actually retired. If the actual timing of the asset retirement is as forecast, all else equal, the depreciation expense for the year for the retired asset should be equal to that forecasted. Alternatively, if an asset is retired earlier/later than forecasted, the actual depreciation recorded for the year will be less/more than forecasted.

Whether total actual depreciation expense recorded for an asset group in the year is less than forecast is not dependent on the gains or losses recorded on the asset retirement. Gains and losses are instead a function of the difference between the actual lives of the assets and their estimated life of the asset group.

44.5 If so, is it possible that ratepayers have over-contributed to gross plant in service in past years?

Response:

Please refer to the response to BCUC 2.44.4.

44.6 Would a deferral account to record variances in forecasted and actual depreciation be appropriate to capture potential variances?

Response:

The FEU note that variances in depreciation expense are not usually of a material amount and tend to be favourable in some years and unfavourable in other years (see response to BCUC IR 2.44.1 where variances are provided, along with explanations for those situations where material variances occurred).

Although a deferral account would eliminate depreciation expense variances, a preferred method would be one that more appropriately focuses on minimizing those differences that result from the timing of regular capital additions and retirements. One method that has been used in the past to accomplish this is to adjust the timing of depreciation commencement.

Currently, FEU begins to depreciate asset additions when the assets are available for use. As a result, actual depreciation expense compared to forecast will vary depending upon the timing of the asset additions and retirements in the forecast period. Prior to adopting IFRS standards for 2010, and consistent with previously approved regulatory treatment, FEU followed the practice of calculating depreciation on the forecast opening plant in service balance each year (so that the depreciation expense is not impacted by the timing of either asset additions or asset retirements in the year). Additions and retirements of assets regardless of the month in which they occur in the year, would for depreciation purposes become effective the beginning of the following year.

FEU believes that calculating depreciation expense on the opening plant in service balance would be preferable to creating a deferral account to capture all depreciation expense variances.

44.7 Is there any instance where actual depreciation recorded against an asset is less than the forecasted depreciation? For example, consider when projects are not constructed/completed on time or when capital assets are not purchased/built as expected.

Response:

In a given year, depreciation expense recorded against an asset can be and has been less than that forecast. For example, capital projects can be delayed for a number of reasons resulting in a delay in the commencement of depreciation, and capital projects can come in under budget, resulting in lower depreciation.

An example where a capital project came in under budget and resulted in less depreciation expense than forecast is the FEI Replacement and Upgrading of Vancouver Low-Pressure Gas Distribution System to Distribution Pressure CPCN project completed in late 2009 (reference: January 2009 Final Completion Report for project). As indicated in the Completion Report, the project was completed under budget and slightly ahead of schedule. With lower capital expenditures and rate base additions, this resulted in lower depreciation expense than expected.

44.7.1 If so, please provide the total amount of the difference between forecasted and actual depreciation, by FEI, FEVI and FEW for each year since 2001.

Response:

Provided below is a summary of forecast and actual depreciation from 2001 to 2010.

FEI
(000s)

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Total Depreciation forecasted in RRA	74,294	-	80,704	89,103	90,736	94,012	92,184	93,668	96,660	98,312	100,534
Actual Depreciation recorded in Gross Plant in Service	75,095	77,504	79,813	87,320	87,605	90,199	86,508	84,097	86,319	98,124	100,187
Variance ($)	(801)	N/A	891	1,783	3,131	3,813	5,676	9,571	10,341	188	347
Variance (%)	-1%	N/A	1%	2%	3%	4%	6%	10%	11%	0%	0%

Notes:

1. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings
2. Revenue Requirement was not filed for FEI in 2002.
3. Depreciation forecasted for 2004-2009 was based on the PBR formula.
4. $100,187 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.

For FEI during the PBR period from 2004 – 2009, the lower depreciation expense compared to forecast was primarily the result of approved capital expenditures being calculated on a formula basis, resulting in lower capital spending than approved and consequently a growing trend of lower depreciation expense than approved, with the savings shared between customers and the Company.

FEVI
(000s)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Depreciation forecasted in RRA	13,906	14,561	14,087	14,397	15,492	15,460	16,339	18,099	23,798	26,231	30,409
Actual Depreciation recorded in Gross Plant in Service	13,336	13,492	14,137	14,334	14,984	15,638	16,189	18,283	23,656	25,975	29,463
Variance ($)	570	1,068	(50)	63	508	(178)	151	(184)	142	256	946
Variance (%)	4%	7%	0%	0%	3%	-1%	1%	-1%	1%	1%	3%

Notes:

1. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings
2. $29,463 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.
3. The variance in 2002 was mainly due to the retirement of computer equipment that was not forecasted in the RRA. Any differences were captured in the Revenue Deficiency Deferral Account (RDDA) with no impact to customers.

For FEVI, either the RDDA (until 2009) or the RSDA (for 2010 and 2011) captures the impact of any variances between the actual and forecast depreciation expense.

FEW
(000s)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Depreciation forecasted in RRA	373	438	470	476	491	-	-	-	501	387	394
Actual Depreciation recorded in Gross Plant in Service	373	438	466	479	485	498	513	500	516	353	366
Variance ($)	(0)	0	4	(4)	5	N/A	N/A	N/A	(14)	33	28
Variance (%)	0%	0%	1%	-1%	1%	N/A	N/A	N/A	-3%	9%	7%

Notes:

1. Figures as provided in the Annual Reports, Annual Review, Settlement Update, and RRA filings
2. Revenue Requirement was not filed for FEW in 2006, 2007, and 2008.
3. $366 thousand in 2011 is the projection from the July 19, 2011 Evidentiary Update.

45.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR 1.86.1, pp. 259-261

Exhibit B-1, Tabs 7.1-7.4, Schedules 43-51

45.1 Calculation of Retirements for Assets Classes Not Subject to Amortization Accounting

Using the historical average percentages provided in the FEU's response to IR1.86.1, Commission staff recalculated the forecasted retirements for the respective asset classes in Tabs 7.1-7.3, Schedules 43-51. Commission staff noted the following discrepancies:

Asset Class	2011 Projected ($000's)	2012 Forecasted ($000's)	2013 Forecasted ($000's)
FEI – Mainland (Tab 7.1)			
474-00 House Regulators and Meter Installations	Per Schedule 44, line 30, column 7 – $0 Recalculation = $10,647 (line 30, column 4)* 111% = $11,818	Per Schedule 47, line 30, column 7 - $1,783 Recalculation - $242 (line 30, column 4) * 111% = $269	Per Schedule 50, line 30, column 7 - $284 Recalculation - $189 (line 30, column 4) * 111% = $210
477-00 Measuring & Regulating Equipment	Per Schedule 44, line 36, column 7 – $0 Recalculation - $3,700 (line 36, column 4) * 18.5% = $685	n/a	n/a
482-00 Structures & Improvements	Per Schedule 45, lines 14-18, column 7 - $6 Recalculation - ($2,555+$100 [lines 14-18, column 4]) * 40% = $1,062	Per Schedule 48, lines 14-18, column 7 - $0 Recalculation – ($3,777+$80 [lines 14-18, column 4]) * 40% = $1,543	Per Schedule 51, lines 14-18, column 7 - $91 Recalculation – ($2,650+$100 [lines 14-18, column 4]) * 40% = $1,100
484-00 Vehicles	Per Schedule 45, line 25, column 7 - $424 Recalculation - $232 (line 25, column 4) * 20.3% = $47	Per Schedule 48, line 25, column 7 - $14 Recalculation - $465 (line 25, column 4)* 20.3% = $94	n/a
FEVI (Tab 7.2)			
482-00 Structures & Improvements	Per Schedule 45, lines 4-8, column 7 -	n/a	Per Schedule 51, lines 4-8, column 7 -

Asset Class	2011 Projected ($000's)	2012 Forecasted ($000's)	2013 Forecasted ($000's)
	$1 Recalculation – ($167+$40 [lines 4-8, column 4]) * 83% = $172		$58 Recalculation – ($335+$30 [lines 4-8, column 4]) * 83% = $303
484-00 Vehicles	Per Schedule 45, line 15, column 7 - $341 Recalculation - $1,207 (line 15, column 4) * 78.8% = $951	Per Schedule 48, line 15, column 7 - $202 Recalculation - $2,913 (line 15, column 4) * 78.8% = $2,295	Per Schedule 51, line 15, column 7 - $1,374 Recalculation - $3,431 (line 15, column 4) * 78.8% = $2,704
FEW (Tab 7.3)			
482-00 Structures & Improvements	n/a	Per Schedule 48, lines 4-8, column 7 - $0 Recalculation – ($200+$75 [lines 4-8, column 4]) * 34.9% = $96	n/a
484-00 Vehicles	n/a	n/a	Per Schedule 51, line 15, column 7 - $0 Recalculation - $60 (line 15, column 4)* 88.8% = $53
FEI – Fort Nelson (Tab 7.4)*			
482-00 Structures & Improvements	Per Schedule 45, lines 4-8, column 7 - $146 Recalculation - $0 (lines 4-8, column 4) * 40% = $0	Per Schedule 48, lines 4-8, column 7 - $0 Recalculation - $129 (lines 4-8, column 4) * 40% = $52	n/a

* Assumption that the historical average percentage is the same as FEI-Mainland

45.2 Please explain how you determined the above retirement amounts for each asset class noted above.

Response:

Provided below is information in a similar format as outlined in BCUC IR 2.45.1 along with narrative to explain how the forecast amounts for each of the asset classes noted were determined. With the exception of asset class 477, all of the asset classes identified in the table in BCUC IR 2.45.1 are subject to amortization accounting, where retirement forecasts are based on knowledge of which assets will become fully amortized in the year. The table incorrectly assumed that the retirements were instead calculated based on a percentage of additions.

Asset Class	2011 Projected ($000's)	2012 Forecasted ($000's)	2013 Forecasted ($000's)
FEI - Mainland (Tab 7.1)			
474-00 House Regulators and Meter Installations	Per Schedule 44, line 30, column 7 - $0 (no retirements and consistent with amortization approach)	Per Schedule 47, line 30, column 7 - $1,783 (assets expected to reach zero net book value in the year; consistent with amortization approach)	Per Schedule 50, line 30, column 7 - $284 (assets expected to reach zero net book value in year; consistent with amortization approach)
477-00 Measuring & Regulating Equipment	$685 = $3,700 (line 36, column 4) * 18.5%	N/A	N/A
482-00 Structures & Improvements	Per Schedule 45, lines 14-18, column 7 - $6 (assets approaching retirement in the year)	Per Schedule 48, lines 14-18, column 7 - $0 (assets approaching retirement in the year)	Per Schedule 51, lines 14-18, column 7 - $91 (assets approaching retirement in the year)
484-00 Vehicles	Per Schedule 45, line 25, column 7 - $424 (assets approaching retirement in the year)	Per Schedule 48, line 25, column 7 - $14 (assets approaching retirement in the year)	N/A
FEVI (Tab 7.2)			
482-00 Structures & Improvements	Per Schedule 45, lines 4-8, column 7 - $1 (assets approaching retirement in the year)	N/A	Per Schedule 51, lines 4-8, column 7 - $58 (assets approaching retirement in the year)
484-00 Vehicles	Per Schedule 45, line 15, column 7 - $341 (assets approaching retirement in the year)	Per Schedule 48, line 15, column 7 - $202 (assets approaching retirement in the year)	Per Schedule 51, line 15, column 7 - $1,374 (assets approaching retirement in the year)
FEW (Tab 7.3)			
482-00 Structures & Improvements	N/A	Per Schedule 48, lines 4-8, column 7 - $0 (assets approaching retirement in the year)	N/A
484-00 Vehicles	N/A	N/A	Per Schedule 51, line 15, column 7 - $0 (assets approaching retirement in the year)
FEI - Fort Nelson (Tab 7.4)			
482-00 Structures & Improvements	Per Schedule 45, lines 4-8, column 7 - $146 (assets approaching retirement in the year)	Per Schedule 48, lines 4-8, column 7 - $0 (assets approaching retirement in the year)	N/A

474-00 House Regulators and Meter Installations

The recalculation for forecast retirements performed by Commission staff as noted in BCUC IR 2.45.1 for this asset class used the historical average percentage. This methodology is inconsistent with what was described in the Application on page 287 where FEU proposed the amortization approach for this asset class.

Using the amortization approach, the forecasted retirements for this asset class were based on expected retirements of assets that are greater than the expected useful life of 22 years. Please refer to section 5.4.2 Depreciation Study and Rates on pages 283 – 287 of the Application and the response to BCUC IR 1.86.3.7 for further discussion.

477-00 Measuring and Regulating Equipment

As discussed in response to BCUC IR 2.57.2, forecasted retirements for 477-00 Measuring & Regulating Equipment were inadvertently excluded for 2011. An amount of approximately $685,000 should have been projected based on the most recent five year historical average of 18.5% of overall anticipated additions for this asset class. This will be reflected in the next Evidentiary Update, although due to the small impact this adjustment has on revenue requirements, it has no impact on the rate proposals in this Application.

482-00 Structures & Improvements

The recalculation for forecast retirements performed by Commission staff for this asset class used the historical average percentage for projecting retirements. As indicated in the response to BCUC IR 86.1, forecast building retirements are based on known retirements.

484-00 Vehicles

Please refer to the response to BCUC IR 2.52.2.

For company owned vehicles, instead of using the historical average of 20.3% of additions, vehicle retirements were forecast based on upcoming retirements in the year. FEI believes this provides for a better estimate of expected retirements than using a historical percentage approach. FEI's company owned vehicles represent only a small portion of the overall company fleet, accounting for approximately 5% of total vehicles.

For FEI leased vehicles, retirements have been forecast based on the recent experience of 60% of lease vehicle additions.

The FEU wishes to clarify the response to BCUC IR 1.86.1 where under the section on General Plant, No Amortization Accounting Applied, there is a reference to "....forecasted known retirements or in the case of vehicles using a percentage of historical additions." The reference to percentage of historical additions is applied to FEI leased vehicles.

46.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.2, pp.262-266

Asset Retirements

46.1 Please confirm that assumptions used in forecasting 2012 and 2013 asset retirements were updated for new information and recent asset retirement experiences.

<u>Response:</u>

The FEU confirm that the assumptions used in forecasting 2012 and 2013 asset retirements were updated for new information and recent asset retirement experiences.

Please refer to the response to BCUC 1.86.1 for an overview of the basis used to forecast the FEU asset retirements for 2012-2013.

47.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3, p.267

402-01 Application Software – 12.5 percent

47.1 Please provide a listing of those assets that make up the $11,301,000 and are expected to be fully amortized in 2011.

<u>Response:</u>

Provided below is a listing of the assets expected to be fully amortized in 2011 along with their original cost that will be retired. This list includes components of larger infrastructure software. These assets are retired at the end of their estimated useful life, when their net book value reaches zero.

Asset No.	Asset Description	Cost ($000's)
10020284	SAP	2,418
10020272	FIS/ODS - Forecasting Information System	2,041
10020266	Business Intelligence Pilot	1,772
10020276	NUCLEUS	1,742
10020287	WINS - Web Interface Nomination System	1,074
10020270	CMS - Content Management System	1,111
10020265	AMFM - Automated Mapping /Facilities Management Sy	898
10020283	2002 Software	100
10020267	BW - SAP Business Information Warehouse	90
10020275	MUP - Mobile Up/Mobile Field	38
10020271	FileNet	17
Total		11,301

48.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.4, pp.267-268

473-00 Services

48.1 FEU's response indicates that the average cost of Services to be retired is $30.75/m. What are the average costs per meter of new Services for 2010 and 2011?

Response:

The average cost of installing new services for 2010 and 2011 are approximately $86 per metre and $88 per metre respectively.

The $30.75 cost per metre referred to in this question represents the cost of the services being retired. Since this cost represents services installed in the past, it is not comparable to the current cost of approximately $86 per metres to install a new service as operating conditions and installation costs have changed.

49.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.5, p.268

483-40 GP Furniture and 486-00 Small Tools & Equipment

49.1 Please provide a description or explanation of what makes up the $1,462,000 and $1,806,000 for GP Furniture and Small Tools & Equipment, respectively, and are expected to be fully amortized in 2011. Please also provide details on how these amounts are determined using the amortization accounting approach (i.e. how the estimated useful lives are tracked and the assets identified for retirement).

Response:

The $1,462 thousand of GP Furniture expected to be retired in 2011 includes furniture ($1,093 thousand), workstations ($162 thousand), chairs ($42 thousand), cabinets and shelving ($29 thousand), other furniture including tables ($136 thousand).

The $1,806 thousand for Small Tools & Equipment expected to be retired in 2011 includes various types of tools and equipment. Given the small amount of dollars for the different tools and equipment under this category, no additional details beyond expenditures by year in-service have been tracked in the SAP system.

These assets are tracked by their asset numbers in the company's SAP system and amortized on a straight-line basis over their useful lives in accordance with the approved Amortization Accounting approach for such assets. Assets approaching a net book value of zero are identified in the SAP system and manually retired when their net book value reaches zero.

50.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.6, pp.268-269

402-01 Application Software – 12.5% and 402-02 Application Software – 20%

50.1 Please provide a description or explanation of what makes up the $2,722,000 and $1,949,000 for Application Software – 12.5% and Application Software – 20%, respectively and are expected to be fully amortized in 2011. Please also provide details on how these amounts are determined using the amortization accounting approach (i.e. how the estimated useful lives are tracked and the assets identified for retirement).

Response:

Provided below are listings of application software expenditures expected to be fully amortized in 2011.

Application Software - 12.5%

Asset No.	Asset Description	Cost ($000's)
10020284	SAP	2,151
10020285	SAP Enterprise Portal	544
10020268	CAFÉ	22
10020276	NUCLEUS	5
Total		**2,722**

Application Software - 20%

Asset No.	Asset Description	Cost ($000's)
10020610	Microsoft License	973
10020609	Documentum	209
10020603	Computer Software- Other Acq 99997	188
10020625	Flex Benefit Application	153
10020628	Teldig One Call	82
10020621	CMMS - Computerized Maintenance Mgmt System	80
10020623	SCADA	77
10020624	Sharepoint	50
10020615	LAPS - Load Analysis and Pressure Survey	39
10020626	GCHM - Gas Commodity Hedging Model	27
10020622	DB/TexWorks	18
10020618	ASBD-As Build & Digitize Com & Control Stns	16
10020616	MICS - Measurement Information Computation System	15
10020627	SRT - Strategic Relationship Tracker	10
10020629	Unclaimed Property Act Database	5
10020607	Commence RM	4
10020604	DCRS- Digitized Construction Records System	4
Total		**1,949**

These assets are tracked by their asset numbers in the Companies' SAP system and amortized on a straight-line basis over their useful life in accordance with the approved Amortization Accounting approach for such assets. Assets approaching a net book value of zero are identified in the SAP system and manually retired when their net book value reaches zero.

51.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.7, p.269

2012 Retirements

51.1 The FEU response to BCUC IR1.86.3.7 indicates that the average retirement cost for 473-00 Services is $500 per service retirement. How does this compare to the $30.75/m average cost of retirement for the 2011 projected service retirements quoted in your response to IR1.86.3.4?

Response:

On an equivalent cost per metre basis, the 2012 service retirement historic cost of $2.9 million (i.e. 5,820 service retirements X $500 per service) is based on forecast activities of approximately 93,000 metres of services at a unit cost of $31.64 per metre of service line. This 2012 projected cost is based on the most recent three-year average and is three percent higher than the $30.75 per metre projected for 2011.

51.2 FEU indicates that the estimated retirements for 474-00 House Regulators & Meter Installations is equal to the assets that are expected to be fully amortized, thereby using the approved amortization accounting approach. However, in your response to IR1.86.0 474-00 House Regulators & Meter Installations is included in the summary of historical average retirement percentages. Please clarify which approach is taken for estimating retirements for this class.

Response:

Please refer to the response to BCUC IR 1.86.1 where an overview of the basis for forecasting 2012-2013 asset retirements is provided. The response to BCUC IR 1.86.1 includes a table showing asset retirements from 2006 to 2010.

Both approaches have been taken for estimating retirements for this class, depending on the year referenced. For years 2010 and prior, retirements for the asset class 474-00 House Regulators and Meter Installations were forecasted using the historical percentage of additions methodology. For the 2011 retirement projections and 2012-2013 forecast, the amounts are based on the amortization accounting approach, consistent with the recommendation set out on Page 287 of the Application Section 5.4.2 (Exhibit B-1).

52.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.8, p.270

2012 Retirements

52.1 Please provide a description or explanation of what makes up the $1,517,000 for GP Computer Hardware and are expected to be fully amortized in 2012. Please also provide details on how these amounts are determined using the amortization accounting approach (i.e. how the estimated useful lives are tracked and the asset identified for retirement).

Response:

Provided below is a listing of assets expected to be fully amortized in 2012.

Asset No.	Asset Description	Cost ($000's)
10018110	All other Hardware	1,507
10014116	All Other Hardware	10
Total		1,517

These assets are tracked by their asset numbers in the company's SAP system and amortized on a straight-line basis over their useful life in accordance with the approved Amortization Accounting approach for such assets. Assets approaching a net book value of zero are identified in the SAP system and manually retired when their net book value reaches zero.

Please note that asset #10018110 includes Desktop & Laptop PC Refresh, IT Infrastructure Evergreening, IT Network Evergreening, IT Storage Infrastructure, Server Refresh Program, and other miscellaneous hardware.

52.2 The response to BCUC IR1.86.0 indicates that for FEI the historical average percentage for 484-00 Vehicles is 20.3%, however, there is no percentage provided for 484-00 Vehicles – Leased. Please clarify if the same percentage should be used for both 484-00 Vehicles and 484-00 Vehicles – Leased. If no, why is 484-00 Vehicles – Leased excluded from your response to IR1.86.0?

Response:

The historical average percentage of 20.3% calculated in the response to BCUC IR 1.86.1 included only those vehicles owned by FEI. Excluded from the table were those vehicles leased by FEI as they were not capitalized prior to 2010. Retirements of leased vehicles have been forecast in the Application based on the recent experience of 60% of lease vehicle additions.

For company owned vehicles, instead of using the historical average of 20.3% of additions to estimate, retirements were forecast based on upcoming retirements in the year. This provides for a better estimate of expected retirements than using a historical percentage approach. FEI's company owned vehicles represent only a small portion of the overall company fleet, accounting for approximately 5% of total vehicles.

53.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR1.86.3.9, p. 270

2013 Retirements

53.1 Please provide a description or explanation of what makes up the $6,015,000 and $2,997,000 for Application Software – 12.5% and Application Software – 20%, respectively, and are expected to be fully amortized in 2013. Please also provide details on how these amounts are determined using the amortization accounting approach (i.e. how the estimated useful lives are tracked and the asset identified for retirement).

Response:

Provided below is a listing of assets expected to be fully amortized in 2013.

Application Software - 12.5%

Asset No.	Asset Description	Cost ($000's)
10020269	Click	4,593
10020267	BW - SAP Business Information Warehouse	591
10020287	WINS - Web Interface Nomination System	467
10020265	AMFM - Automated Mapping /Facilities Management Sy	130
10020284	SAP	106
10020271	FileNet	55
10020270	CMS - Content Management System	45
10020275	MUP - Mobile Up/Mobile Field	27
Total		**6,015**

Application Software - 20%

Asset No.	Asset Description	Cost ($000's)
10020610	Microsoft License	790
10020634	PMW - Project Management Workflow Tool	520
10020640	CPS Redwoods	262
10020637	Microsoft Exchange	234
10020636	CPDMS - Cathodic Protection Data Management System	162
10020638	Peace CIS Application Testing	140
10020631	BizTalk	127
10020606	Prover - Meter Shop Prover System	231
10020639	Uperform	93
10020625	Flex Benefit Application	128
10020603	Computer Software- Other Acq 99997	150
10020633	FireCall	49
10020632	Esker DeliveryWare Platform Solution	50
10020616	MICS - Measurement Information Computation System	42
10020635	SAM - Safety Alert Message System	10
10021118	IC&T	9
10020605	MACS	1
Total		**2,997**

These assets are tracked by their asset numbers in the company's SAP system and amortized on a straight-line basis over their useful life in accordance with the approved Amortization Accounting approach for such assets. Assets approaching a net book value of zero are identified in the SAP system and manually retired when their net book value reaches zero.

54.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR 1.86.3.10, p.271

2013 Retirements

54.1 The response to BCUC IR1.86.3.10 indicates that the average retirement cost for 473-00 Services is $500 per service retirement. How does this compare to the $30.75/m average cost of retirement for the 2011 projected service retirements quoted in your response to IR1.86.3.4?

<u>Response:</u>

On an equivalent cost per metre basis, the 2013 service retirement historic cost of $2.8 million (i.e. 5,500 service retirements X $500 per service) is based on forecast activities of approximately 89,000 metres of services at an unit cost of $31.64 per metre of service line. This 2013 projected cost is based on the most recent three-year average and is three percent higher than the $30.75 per metre projected for 2011.

Please refer to the response to BCUC 2.51.1 for 2012 forecast retirements.

55.0 Reference: Forecasted Retirements

Exhibit B-9, BCUC IR 1.86.3.11, pp. 271-272

2013 Retirements

55.1 Please provide a description or explanation of what makes up the $6,489,000 and $1,954,000 for 483-10 GP Computer Hardware and 483-40 GP Furniture, respectively, and are expected to be fully amortized in 2013. Please also provide details on how these amounts are determined using the amortization accounting approach (i.e. how the estimated useful lives are tracked and the assets identified for retirement).

Response:

Provided below are details of 483-10 GP Computer Hardware and 484-40 GP Furniture assets expected to be fully amortized in 2013.

For Computer Hardware, assets scheduled to be retired are made up of a number of smaller items, including Hardware – Distribution Mobile System, Host Computer for Grand Forks Mainline / Rectifier Desktop & Laptop PC Refresh, IT Infrastructure Evergreening, IT Network Evergreening, IT Storage Infrastructure, Server Refresh Program, Printer Refresh Program, Toughbook Laptop Refresh, Backup Infrastructure Upgrade, Infrastructure Centralized Services, and other miscellaneous hardware.

Furniture expected to be retired in 2013 includes workstations ($697 thousand), furniture ($596 thousand), chairs ($330 thousand), cabinets and shelving ($102 thousand), other furniture including tables ($229 thousand).

The assets are tracked by their asset numbers in the company's SAP system and amortized on a straight-line basis over their useful life in accordance with the approved Amortization Accounting approach for such assets. Assets approaching a net book value of zero are identified in the SAP system and manually retired when their net book value reaches zero.

56.0 Reference: Forecasted Plant Additions

Exhibit B-9, BCUC IR 1.86.5.1, p.273

Projected 2011 Additions

56.1 Please confirm that the Integrated Work Management System and Microsoft License within 402-01 Application Software – 12.5%, replace application software that are expected to be fully amortized in 2011.

Response:

Integrated Work Management System is replacing application software that is fully amortized. Microsoft License represents the replacement of expenditures from 2006 placed into service which have been depreciated at 20% per year.

57.0 Reference: Forecasted Plant Additions

Exhibit B-9, BCUC IR1.86.5.2

Exhibit B-1, Table 6.2-14, p. 361

Exhibit B-1, Table 6.2-7, p. 345Exhibit B-1, Tab 7.1, Schedule 44

Projected 2011 Additions

57.1 Per the response to BCUC IR 1.86.3.4 the projection of 475-00 Mains expected to be retired in 2011 is based on 35,781 metres of Main. In addition, in Table 6.2-14 of Exhibit B-1, the projected unit cost per metre for Mainland Mains is estimated at $57/m. Given this information, the estimated cost of retired Mainland Mains to be replaced with new units would be $2,039,517. However, projected 2011 costs of replacements per response to IR1.86.5.2 for 475-00 Mains appears to be at least $3,257,000 out of the total projected additions of $16,788,000. Please explain why replacements are projected to be greater than the projected unit cost/m as stated in Table 6.2-14 of exhibit B-1.

Response:

To clarify, the information included in BCUC 1.86.3.4 pertains to the projected metres of **existing main retired** along with their historical unit costs. In this case, distribution mains forecast to be retired in 2011 is 35,781 metres at a historical average unit cost of $28.53 totalling to $1,021,000.

Table 6.2-14 of Exhibit B-1 contains the projected unit cost to add a metre of **new main to service new customers.** In 2011, total forecasted metres of new main are 100,724 metres at an expected unit cost of $57 per metre totalling to $5,738,000.

Schedule 44 referenced in the response to BCUC 1.86.5.2 (line 33 for 475 Mains) indicates $16,788,000 of mains spending in 2011 of which $5,738,000 is for New Mains while the remainder of approximately $11 million is for mains upgrade/replacements. The average unit cost for 2011 replacement mains at a total cost of $11 million and activity of 35,781 metres is expected to be approximately $309 per metre of main.

It is incorrect to take the projected metres of mains to be retired in 2011 at 35,781 metres and use the $57 per metre for new mains to service new customers to arrive at a total cost of $2,039,517 for upgrade and replacement mains work. New mains to serve new customers and mains for upgrades and replacements are different. For replacement activities, there is much more effort required as there are structures/services and developed surfaces already in place. Also, work must be completed without disrupting service to customers in the area. These types of conditions lead to higher unit costs for replacement mains work compared to new mains activities.

57.2 Additions to 477-00 Measuring & Regulating Equipment consists of $1,780,000 in replacement assets for 2011. However, per Schedule 44 of Exhibit B-1, Tab 7.1, retirements are expected to be $nil for 2011. Please explain why replacements are projected for 2011 when no retirements are expected.

Response:

Retirements for 477-00 Measuring & Regulating Equipment were inadvertently excluded for 2011. An amount of approximately $685,000 should have been projected based on the most recent five year historical average of 18.5% of overall anticipated rate base additions of $3.7 million ($1.8 m current year capital expenditure plus $1.9 m for work in progress) for this asset class. This will be reflected in the next Evidentiary Update, although due to the small impact this adjustment has on revenue requirements, it has no impact on the rate proposals included in this Application.

57.3 Projected 2011 additions for 478-10 Meters is estimated at $10,647,000, while Table 6.2-7 on p. 345 in Exhibit B-1 shows Total Sustainment Capital for Meters to be approximately $19,525,000 and Total New Capital for Meters to be approximately $1,782,000. Why is there difference between projected additions for Meters and Total Sustainment and New Capital for Meters? Please explain how the $10,647,000 in additions relate to the capital expenditures shown in Table 6.2-7.

Response:

Table 6.2-7 on p. 345 in Exhibit B-1 shows the 2011 total anticipated Meter related capital expenditures to service new customers and existing customers (i.e. replacement). The projected $21 million in total capital expenditures ($19.5 million + $1.78 million) in meter costs includes installation labour, regulators and meters. Based on past experience, half of the total meter costs (i.e. 50% of $21 million = $10.6 million) are expected to be for the actual meters (Asset Class 478-10 Meters) with the rest (i.e. $10.6 million) for Asset Class 474-00 House Regulators & Meter Installations.

58.0 Reference: Forecasted Plant Additions

Exhibit B-9, BCUC IR 1.86.5.9

Forecasted 2013 Additions

58.1 482-00 Structures & Improvements – Masonry Buildings includes a forecasted $600,000 for the replacement of the Williams Lake Muster. Please confirm that the muster station that is being replaced is fully amortized and will be retired in 2013.

Response:

The muster station being retired in 2013 has been in-service since 2000 and will not have been fully amortized.

Changing business needs requiring increased storage space, security and accessibility will necessitate a different location. Initially, the current building was designed to operate primarily as an office space. However, with the centralization of office activities at the Prince George facility, the Williams Lake building is instead now being utilized to support operating and construction activities. The new building will provide storage for emergency and construction equipment and provide for greater security and increased accessibility.

Replacing this building is necessary to properly manage the business activities at this location.

59.0 Reference: Sustainment Capital Expenditures

Exhibit B-1, Section 6.2.2.5, pp. 344, 349-350

Exhibit B-9, BCUC IR 1.88.1, p.298

Distribution System Reinforcement, Integrity & Reliability Capital – Mainland

59.1 Per Table 6.2-6 on p. 344 and commentary on pp.349-350 of Exhibit B-1, 2010 actual capital expenditures for Distribution System Reinforcements/Integrity and Reliability were $5.2 million compared to the 2010 approved amount of $7.9 million. Of the $2.7 million in underspending, $1.15 million in spending is deferred to future years and $1 million was attributed to cost savings on the relocation of the Highland Valley Lateral.

59.2 Were the deferrals of 2010 approved amounts factored into the forecast of 2012 and 2013 capital expenditures? (i.e. 2012 and 2013 forecasted capital expenditures exclude expenditures relating to previously approved amounts)

Response:

The 2010 delayed / deferred distribution system reinforcement expenditures are not factored in as a reduction (i.e. netted) to 2012-2013 capital requirements. Any current year planned work deferred to future years is factored into the planned work for those future years.

59.3 Does FEI-Mainland intend to pass on the cost savings in the relocation of the Highland Valley Lateral on to rate payers?

Response:

Only the actual amount of costs incurred in the relocation of the Highland Valley Lateral are included in rate base during the forecast period. Thus, the lower costs will be passed on to customers.

60.0 Reference: Growth Capital Expenditures

Exhibit B-1, Section 6.2.1, Table 6.2-1, p. 332

Exhibit B-9, BCUC IR1.88.1, p.298

Growth Capital Expenditures - Mainland

60.1 2010 actual Growth Capital Expenditures in total were approximately $4.8 million less than the 2010 approved amount and 2011 projected expenditures are expected to be approximately $1.3 million short of the 2011 approved amount. Please confirm whether this 'underspending' is factored into the forecast for 2012 and 2013 and whether forecasted 2012 and 2013 amounts are net of these favourable variances. If not, please explain why.

Response:

The 'underspending' in growth capital from that approved for 2010 and 2011 is factored into the 2012-2013 rate base forecast but the 2010-2011 net capital expenditure favourable variances are not factored in as a reduction (i.e. netted) to 2012-2013 growth capital requirements.

Growth capital expenditures are derived from activity and unit cost forecasts. Activity forecasts are largely driven by customer additions forecast whereas unit cost forecasts are derived from recent actual unit cost experience. For 2010-2011, the growth capital requirements were prepared based on the best information available at the time. However, circumstances changed from the time the capital budgets were prepared to the current conditions. In retrospect, actual customer additions and unit costs have been lower than previously forecast for 2010-2011 resulting in the observed capital variances.

Given that the FEU have experienced lower customer additions and unit costs in recent years, the 2012-2013 growth capital forecasts have been adjusted to incorporate these assumptions.

61.0 Reference: Capital Expenditures

Exhibit B-1, Section 6.2.2.7, pp. 352-356

Exhibit B-9, BCUC IR 1.88.1, p. 299

Exhibit B-9, BCUC IR 1.93.2, pp.311-312

Transmission System Reinforcements/Integrity and Reliability – Vancouver Island Distribution System Reinforcements/Integrity and Reliability – Vancouver Island Growth Capital Expenditures

61.1 2010 actual transmission expenditures were approximately $1.3 million less than the 2010 approved amounts, resulting from unused contingency funding. 2012 and 2013 forecasted also includes $2 million in contingency funding. It would appear that the 2012 forecasted contingency funding is at $3.3 million compared to $700,000 in contingency funds used in 2010. If $1.3 million was unused in 2010, why is it not carried forward into 2012 and the 2012 forecasted additional contingency funding estimated at $700,000 instead of the full $2 million? Note that 2011 is not factored in this question because it is projecting to equal the 2011 approved amount.

Response:

The established FEU accounting/budgeting practice is that capital budgets are established for each calendar year and this includes a practice that unused capital funding in the current year is not carried forward to the following year. Thus, all of a contingency amount planned for the current year for necessary work not known at the time of budget preparation, months or years before, may or may not be spent during the calendar year. In some years, there may be a need for a greater amount of funds than the contingency and in other years less. The internal budget practice has been to budget an average amount for contingency. If contingency capital funds are not used during the current calendar year, the funds become unavailable for future years based on the established FEU accounting/budgeting practice.

For FEVI, the RSDA account captures the impact of any variances between the actual and forecast capital expenditures.

61.2 2010 actual Distribution System Reinforcement Expenditures were lower than the approved amounts, as some of the planned expenditures were delayed and are being deferred into future years. Are these deferred amounts factored into the forecasts for 2012 and 2013 (i.e. 2012 and 2013 forecasted Distribution System Reinforcement Expenditures are net of these deferred amounts)?

Response:

The 2010 delayed / deferred distribution system reinforcement expenditures are not factored in as a reduction (i.e. netted) to 2012-2013 growth capital requirements. Any current year planned work deferred to future years is factored into the planned work for those future years.

For FEVI, the RSDA account captures the impact of any variances between the actual and forecast capital expenditures.

61.3 2010 actual and 2011 projected Growth Capital Expenditures are far less than the amounts approved for 2010 and 2011. Are the expected cost savings factored into the 2012 and 2013 forecasted amounts (i.e. 2012 and 2013 forecasted Growth Capital Expenditures are net of these amounts)?

Response:

The underspending in growth capital expenditures from that approved for 2010 and 2011 is factored into the 2012-2013 rate base forecast but the 2010-2011 net capital expenditure favourable variances are not factored in as a reduction (i.e. netted) to 2012-2013 growth capital expenditures. The methodology for forecasting the Vancouver Island growth capital expenditures is presented in the Application on pages 365-368.

Growth capital expenditures are derived from activity and unit cost forecasts. Activity forecasts are largely driven by customer additions forecast whereas unit cost forecasts are derived from recent actual unit cost experience. For 2010-2011, the growth capital requirements were prepared based on the best information available at the time. However, circumstances changed from the time the capital budgets were prepared to the current conditions. In retrospect, actual customer additions and unit costs have been lower than previously forecast for 2010-2011 resulting in observed capital variances. Given that the FEU experienced lower customer additions and unit costs in recent years, the 2012-2013 growth capital forecasts have been adjusted to incorporate these assumptions.

The RSDA account for FEVI captures the impact of any variances between the actual and forecast capital expenditures.

62.0 Reference: 13 Month Adjustment

Exhibit B-9, BCUC IR 1.89.1, p. 304

Exhibit B-9-1, Attachment 85.1, 085.1 Live Spreadsheet

13 Month Adjustment for CCE – FEI 2012

62.1 The 2012 CCE 'In Service Amount' for FEI- Mainland of $81,134,000 does not agree to the total CPCN Additions of $66,470,000 under the Customer Care Enhancement Project on Tab 42.1-FEI in Exhibit B-9-1, Attachment 85.1, 085.1 Live Spreadsheet. Please explain why there is a difference.

Response:

The total captial CPCN addition in 2012 for the CCE project is $66.470 million. The response to BCUC IR 1.89.1 did not segregate out the Tilbury Land Purchase additions from the total CPCN additions for FEI in 2012, inadvertently categorizing $14.664 million of CPCN additions as related to CCE. The revised table below shows the two components of the $40.567 million 13-month adjustment as presented in Tab 7.1, Section 7, Schedule 40, correctly identifying the in-service amounts and 13-month adjustments related to the CCE capital Project and the Tilbury Land Purchase.

FEI - 2012	In Service Date	In Service Amount		13 month Adjustment
CCE	1-Jan-12	66,470	(13/13) - .5	33,235
Tilbury Land Purchase	1-Jan-12	14,664	(13/13) - .5	7,332
		81,134		40,567

63.0 Reference: Facilities and Equipment Capital - Mainland

Exhibit B-9, BCUC IR 1.95.1, pp. 321-322

North Vancouver Muster Station

63.1 The response to BCUC IR1.95.1 indicates that industrial land in North Vancouver is extremely scarce and there have been very few sales in the recent past. As such, is it realistic that FEI-Mainland will be able to acquire land for the North Vancouver Muster Station in 2012?

Response:

It is FEI's preference to purchase the land and build the muster facility to the current specifications for muster sites. This allows for consistency in muster sites which aids in standardization in operations and maintenance for the muster facilities and assists in prudently managing the operating costs for the facilities. FEI recognizes there is risk of this preference not being attained as a result of the scarce availability of industrial land but it is reasonable to target this as the preferred option as there have been industrial land sales within this market over the past few years. If FEI is not able to acquire land and build then FEI will look to other options as identified in response to BCUC IR 2.63.2 and 2.63.3

63.2 What are the FEI-Mainland's plans if it cannot acquire land for the North Vancouver Muster Station?

Response:

As stated in response to BCUC IR 2.63.1, it is FEI's preference to purchase land in North Vancouver and build a muster site to our current specifications. If land does not become available, and FEI is not able to acquire land, FEI will direct its effort to free-standing building sales. FEI believes there are more opportunities on a sale basis for this type of building. FEI has not focused on this option to date, as there is limited yard space and it is therefore not preferred. Most buildings in North Vancouver are older and over-built and the structures generally run right to the lot-line leaving no yard space. The standard muster build requires yard space to store various non-temperature sensitive material. If a larger building is purchased this material could be stored inside but this would come with a higher acquisition cost and higher ongoing O&M costs. For this reason, FEI's first preference remains to purchase land in North Vancouver and build a muster site to our current specifications.

63.3 Although, FEI-Mainland has estimated $2 million for the required parcel land, what is the maximum that the FEI-Mainland will spend? We acknowledge the sensitivity of this question. As such, please provide your response confidentially if required.

Response:

Currently FEI is targeting the project as an acquisition of land and build at the current budgeted cost of $2.5 million, which is also the current maximum. Many other options exist such as acquiring free-standing buildings, strata or subdivision of larger properties. FEI believes it will be able to achieve replacement of the North Vancouver Muster through an acquisition; any increase beyond the current limit of $2.5 million is subject to the required management review and approval process to ensure the purchase price is reasonable for the purpose of a muster site.

64.0 Reference: IT Expenditures

Exhibit B-9, BCUC IR1.96.1, p. 325

Twelve 2010 IT Projects Deferred

64.1 Are the estimated costs related to the twelve deferred 2010 IT projects included in the 2012 and 2013 forecasted IT Expenditures? If so, why would they be included if they were previously approved in 2010 but were unspent?

Response:

As discussed in the response to BCUC IR 2.61.1, the established FEU budgeting practice is that capital budgets are established for each calendar year and this includes a practice that unused capital funding in the current year is not carried forward to the following year.

As detailed in the Application (Exhibit B-1) Section 6.2.5, pages 377 and 378 and expanded upon in the response to BCUC IR 1.97.1, the 12 projects deferred from 2010 may be considered for the 2012 or 2013 IT Portfolios in accordance with the established IT Portfolio Selection process. The capital budgets for 2012 and 2013 are distinct and the composition of the respective IT Portfolios will be determined by the established IT Portfolio Selection process. All projects, including the deferred ones from 2010, will need to re-compete for resources and budget to be included in the future Portfolio.

65.0 Reference: Growth Capital Expenditures

Exhibit B-9, BCUC 1.101.3

Uneconomic Main Extensions

FEVI New Customer Mains

	2006	2007	2008	2009	2010	Year to date 2011
Forecast cost	N/A	N/A	2,429,162	2,457,625	1,120,986	833,253
Actual cost	1,691,595	3,469,655	2,901,346	4,051,022	888,140	1,106,766
Variance	N/A	N/A	472,184	1,593,397	-232,846	273,514
% Variance	N/A	N/A	19%	65%	-21%	33%
# of Mains	208	364	187	111	106	63

Year to date as of May 31, 2011

65.1 From 2008-2011 Year-to-date, FEVI has under estimated the cost of installing a main extensions by $2.1 million. Should a portion of these costs be written off and removed from rate base? If not, why not?

Response:

No, none of the costs discussed in the question should be written off. Four reasons are summarized below.

1. **The question only focuses on costs whereas the profitability index ("PI") is a comparison of both revenue and costs.**

   The FEU System Extension and Customer Connection Policies use a discounted cash flow test to evaluate main extensions, also known as the MX test. The test is a 20 year discounted cash flow analysis which compares the present value of cash inflows to the PV of the cash outflows from a proposed main extension. The cash inflows of the MX test are the revenues from the rates and fees paid by customers served by the main extension. The cash outflows are the estimated cost for FEI/FEVI to build and operate the extension including capital costs for materials and installations of the main, service line and meter and ongoing operating and maintenance costs.

2. FEI and FEVI have met the MX objectives and processes approved by the Commission.

As discussed in the response to BCUC IR 1.102.2, Order No. G-152-07 dated December 6, 2007, regarding the FEI-FEVI (then TGI-TGVI) System Extension and Customer Connection Policies Review, the Commission Panel approved the objectives to promote fair and equitable treatment of customers, to avoid undue discrimination and to ensure that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of that year. The individual threshold PI of 0.8 was approved by the Commission for individual main extensions, along with an aggregate PI of 1.1. The targeted aggregate PI of 1.1 was chosen because it was more conservative than requiring a PI of 1.0 and therefore able to accommodate unanticipated variances in either cost or consumption that may occur. Even if a main extension hypothetically has a PI value less than 0.8 at the end of the five year period, it is the aggregate threshold that demonstrates whether the existing customers received a benefit from the attachment of new customers on an aggregate basis. An aggregate PI of 1.1 ensures that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of that year. Removing underperforming main extensions would be akin to receiving a premium for over performing economic main extensions (e.g. PI>1.0) which contradicts the rationale for having an aggregate threshold. Order G-152-07 treats all main extensions equally with no special treatment for either over- or under-performing main extensions.

From 2008-2011, FEI and FEVI followed the approved process that if any individual MX test resulted in a PI of less than 0.8, the MX would only have proceeded provided that the shortfall in revenue was eliminated by Contributions in Aid of Construction by customers to be served by the MX. Furthermore, the Companies ensured that the targeted aggregate PI for both utilities was at least 1.1.

3. The cumulative cost variances between 2008 and year-to-date 2011 are reasonable in that they are as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.

The Companies have the internal processes and controls in place, along with the use of geo code and manual estimating, to ensure forecast costs are as accurate as possible. Despite these controls and processes the Companies have in place, along with the experience and expertise in forecasting costs, environmental circumstances can be highly variable and unpredictable leading to variances in costs.

Of the cumulative $2.1 million in cost variance, a significant portion ($1.2 million equivalent to 57% of the total) was as a result of Shawnigan Lake Road main extension. The cost estimate for the Shawnigan Lake MX was based on the Commission approved geo-code methodology. Following a review of the Shawnigan Lake MX and our cost estimating process, the FEU have implemented a manual cost estimating methodology in order to reduce the variance between the actual and estimated costs.

4. The comparison of forecast versus actual cost, consumption and PI is provided to the Commission for information purposes only.

As discussed in the FEI and FEVI 2010 Year End MX and Vertical Subdivisions Reports submitted to the Commission June 1, 2011 (the "2010 MX Report"), actual individual and aggregate main extension values using actual consumption and cost data are provided to the Commission for information purposes only at the end of the five year period. Any potential variance between forecast and actual cost, consumption or PI should not form a basis for hypothetically removing costs from rate base.

In summary, the FEU believe that none of these costs should be written off and removed from rate base for the following reasons:

- Evaluation of MX Tests should focus on the ratio of cost and revenue (i.e. the PI).
- The FEU have followed the Commission approved MX Test objectives and processes.
- The cost variances between 2008 to year to date are reasonable.
- Cost variance is provided to the Commission for information purposes only.

66.0 Reference: Capital Growth Expenditures

Exhibit B-9, BCUC IR 1.102.1

2009 Year End TGI-TGVI Main Extension & TGI Vertical Subdivision Reports (2009 MX Report), p. 11

FEI and FEVI Main Extension Review

"The Companies will not, in the interim, be annually re-forecasting consumption for individual main extension projects and then subsequently re-running individual MX Tests to develop re-forecast PI values.

…First, re-forecasting attachment and consumption data for hundreds of main extensions each year would be impractical and create an undue administrative burden. If the Companies were to adopt this practice, the Companies could be in the position of rerunning thousands of main extension tests at the end of a five-year period resulting in the need to hire at least one additional full-time employee."

"2008 PI with Year 1 Actuals

With actual results for Year 1 attachments and annual consumption now available for those main extension projects completed in 2008, the forecast results for Year 1 were updated with actual results, and the main extension test was re-run. The results are illustrated in the following table." (2009 MX Report, p. 11)

66.1 Given that FEU re-forecasted the 2008 PI for Year 1 attachments and consumption please explain why this has become impractical and created "an undue administrative burden".

<u>Response:</u>

When the Companies referred to "undue administrative burden" it applied to re-forecasting consumption for every individual MX test annually and then re-running each individual test. This could result in the Companies re-forecasting and re-running thousands of MX tests each year. The Companies have always believed that this was an impractical approach. Given that there are potentially 2,000 extensions on a rolling-basis, this can make the re-forecasting and re-running of the MX Tests very labour-intensive and time consuming. This also applies if the Companies were to report on a random sample of the entire main extension population.

The Companies believe that there is limited value in reporting on a re-forecasted PI value based on re-forecasting consumption for every main extension annually and then re-running MX Tests.

Consequently, the Companies believe it would not be in the best interests of our customers to pursue such a course of action.

In addition, as described in the response to BCUC IR 2.65.1, cost, consumption and PI variance data is provided to the Commission for information purposes only. The five-year period in the MX Test is only relevant in determining the reconciliation and potential refunds associated with a contribution in aid of construction ("CIAC") provided by a customer(s). Twenty years is a more the appropriate time horizon to view main extensions, corresponding to the twenty-year discounted cash flow model used in the PI.

The re-forecasted PI results presented in the 2009 report did not incorporate re-forecast consumption data for the remainder of the five-year period. The consumption data presented was based on year-to-date actual data plus the original forecast for the year to date to the year-five time frame. A further explanation of this approach was included in FEI and FEVI 2010 Main Extensions Report and FEI Vertical Subdivision Report (the "2010 MX Report"), pages 17-18.

As discussed in the 2010 MX Report, the methodology used in 2008 and 2009 presented an unrealistically negative picture of MX test results because it did not account for the possibility that consumption that did not materialize as forecast might show up at some later point in the five-year time frame. Delayed attachments are a particularly salient issue during the bearish period such as 2009 because the delayed attachments tend to rebound along with the BC housing market. For example, the delayed attachments from 2009 generally materialized in 2010.

66.2 The existing FEU O&M budget includes the cost of an individual to annually re-forecast the main extension PI. Please explain why "least one additional full-time employee" is requires to perform this activity.

Response:

While the existing FEU O&M budget includes the cost of an individual to support main extensions, the budget does not include the cost of an additional individual to re-forecast and re-run main extension tests each year. Re-forecasting and re-running main extension tests is currently beyond the workload for the MX support personnel included in the O&M budget.

If the Companies were to re-forecast attachment and consumption data for hundreds of main extensions each year and to develop re-forecasted PI values based on re-forecasted consumption for every main extension annually, a further additional person would be required for gathering and refreshing the necessary inputs (e.g. re-forecasted attachments and consumption) and re-running approximately two-thousand main extension tests on a rolling basis with the updated data, every year.

As discussed in the response to BCUC IR 2.66.1, the FEU believe re-forecasting attachment and consumption data each year would be of limited value and create an undue administrative burden.

67.0 Reference: Capital Growth Expenditures

Exhibit B-9, BCUC 1.102.2

Impairment Testing of Main Extensions

There appears to be a misunderstanding regarding BCUC 1.102.2. The question has been rephrased for clarity.

67.1 If a 2008 main has a PI <0.8, **should a portion of the capital cost** associated be removed from rate base in order to achieve a PI of 0.8? Please explain why or why not?

Response:

No. Please refer to the response to BCUC IR 2.65.1.

68.0 Reference: Capital Growth Expenditures

Exhibit B-9, BCUC 1.8.1 and BCUC 1.102.2

Impairment Testing of Main Extensions

"FEVI and FEW have in place financial reporting processes that monitor for asset impairment on an annual basis." (Exhibit B-9, BCUC IR 1.8.1)

68.1 Please provide the FEU financial reporting processes for monitoring asset impairment on an annual basis.

Response:

Long-lived assets (deferral accounts, tangible and intangible assets) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. An example of an event or change in circumstance that would trigger an impairment review would be where certain assets are removed from rate base and/or denied partial or full recoverability from the customer.

68.2 The mains installed in 2008 will have 5 full years of consumption history in 2013. Will FEU test these main extensions for impairment (i.e. discounted cash flows are less than the carrying value of the asset)?

Response:

Please see the response to BCUC IR 2.65.1.

68.2.1 If not, why not?

Response:

Please see the response to BCUC IR 2.68.1

68.2.2 If not, when does FEU propose to test main extensions for impairment?

Response:

Please see the response to BCUC IR 2.68.1.

69.0 Reference: Rate Base

Exhibit B-9, BCUC IR 1.109.2, pp. 358-359

Vancouver Island Gas Cost Variance Account (GCVA)

"FEVI is not opposed to reporting the GCVA and the RSDA forecast balances on an annual basis and suggests such reporting be completed at the time of the fourth quarter gas cost reports for the other FEU entities and service areas are filed with the Commission. Further, nothing precludes FEVI from filing an application at other times should the GCVA or RSDA balances indicate an unacceptable build."

69.1 Please define what FEVI would consider to be "an unacceptable build".

Response:

FEVI continues to have a different regulatory construct than the other natural gas entities comprising the FEU. Since 2010 the FEVI Core Market rates have been frozen at the 2009 approved rates.

On May 4, 2011 the FEU submitted its 2012-2013 RRA. Within the Application FEVI is seeking approval to maintain Core Market rates frozen for a further two-year period commencing January 1, 2012. FEVI proposes to utilize part of the surplus in the RSDA to offset the forecast revenue deficiency in 2013; the resultant closing RSDA after tax balances are $53.6 million in 2012 and $42.2 million in 2013.[9]

While there is zero forecast GCVA balance and sufficient forecast surplus in the RSDA to cover the forecast revenue shortfall resulting from the proposed rates in 2013, this mechanism provides only a temporary solution. Although somewhat mitigated by reductions in the forecast cost of gas, there is upward pressure on FEVI's cost of service post-2012 due to the cessation of the Royalty Revenue payments; FEVI has long recognized that a permanent solution is required. In the pending Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011, the FEU will make the case that amalgamation of FEVI with the other entities, coupled with rate harmonization / postage stamp rates for the amalgamated entity, is the lasting solution to mitigate the projected rate increases anticipated due to the cessation of the Royalty Revenues paid to FEVI.

Nonetheless, FEVI will want to ensure the overall forecast net surplus 2012 and 2013 balances of the GCVA and RSDA are not severely eroded by unexpected events such as a significant

[9] FEU 2012 and 2013 RRA, July 19, 2011 Evidentiary Update, Table 7, Page 7

increase in the market prices of natural gas. FEVI notes it is the net balance of the GCVA and RSDA which is of importance in managing the effects of FEVI's cost pressures on future rates and that generally speaking, a larger than forecast surplus balance is beneficial to dealing with the higher future cost of service while a lower than forecast surplus balance only exacerbates the challenge.

In the case that the market prices of natural gas were to move downwards, the overall GCVA and RSDA surplus would be expected to increase and FEVI would not anticipate that any mid-term review or action would be required. The magnitude of the incremental surpluses related to downward movements in the market price of natural gas is limited due to the fact that there is a price floor which, on a sustained basis, has to be above zero. Further, incremental surplus balances are not seen to be detrimental to future FEVI rate setting regardless of whether the FEU amalgamation and rate harmonization is successful effective January 1, 2013.

On the other hand, in the case that the market prices of natural gas were to move upwards, the overall GCVA and RSDA surplus would be expected to decrease. Minor upward price movements, either in magnitude or duration would not cause FEVI to request a mid-term review as minor movements can be absorbed within the overall forecast surplus. However should an unforeseen and sustained escalation in the market price of natural gas occur such that the overall GCVA and RSDA surplus were to be eroded, and at the same time the FEU amalgamation and rate harmonization is not successful effective January 1, 2013, then it may be necessary for FEVI to seek a mid-term rate increase in order to prevent an overall deficit at the end of 2013.

69.2 What would likely be requested in such an application filed in response to "an unacceptable build"?

Response:

Please refer to the response to BCUC IR 2.69.1.

69.3 Would FEVI likewise consider there might be a point in the opposite direction where the GCVA or RDSA balances indicate an "unacceptable drawdown"? If so, what would FEVI consider an "unacceptable drawdown" and what would be the likely requested action?

Response:

Please refer to the response to BCUC IR 2.69.1.

70.0 Reference: Capital Growth Expenditures

Sooke Main Extension 2008 Annual Report, p. 4

Impairment Testing of Main Extensions

70.1 Please update page 4 of the Sooke Main Extension 2008 Annual Report to include 2009 and 2010 data, and add a column to calculate revenue variance (Volume Variance x Revenue/GJ). Also provide the table in fully functional electronic format.

Response:

On November 7, 2002, FortisBC Energy (Vancouver Island) Inc. ("FEVI") then Centra Gas British Columbia Inc., filed a Certificate of Public Convenience and Necessity ("CPCN") application for the Sooke Main Extension. On December 30, 2002, the Commission approved the CPCN application by Commission Order No.C-15-02. In the Decision related to Order C-15-02 the Commission accepted the load forecast provided in the moderate scenario and accepted that the economics of the project justified its approval. The Sooke Main Extension load forecasts and economics approved by the Commission were based on the best available information at the time. The Commission also ordered FEVI to provide a comprehensive final report on the project and to provide annual reports for five years that compare the actual customer and load additions for the Sooke Main Extension to the forecast. FEVI fulfilled its reporting requirements by filing the fifth and final report with the Commission on November 26, 2008.

The Sooke Main Extension data requested is not readily available at this time as the fifth and final report was filed with the Commission approximately two and a half years ago.

The response to BCUC IR 2.65.1 provides a detailed description of how the objectives of the current MX Test are to promote the fair and equitable treatment of customers, to avoid undue discrimination and to ensure that the addition of a full year's cohort of customers does not adversely affect customers in existence at the beginning of the year.

The individual threshold PI of 0.8 was approved by the Commission for individual main extensions, along with an aggregate PI of 1.1. Even if a main extension has a PI value of less than 0.8 at the end of the five year period, it is the aggregate threshold that demonstrates whether the existing customers received a benefit from the attachment of new customers on an aggregate basis. Removing underperforming main extensions would be akin to receiving a premium for over performing economic main extensions. Order G-152-07 treats all main extensions equally. Special treatment for either over or under performing main extensions would contradict the rationale for having an aggregate threshold.

The response to BCUC IR 2.66.1 went on to describe how the five-year period is only relevant in determining the reconciliation and potential refunds associated with a CIAC provided by the customer(s). Accordingly, reviewing additional data beyond the approved reporting requirements on potentially underperforming main extensions is not relevant.

71.0 Reference: Distribution O&M Expenditures and Employees

Exhibit B-1, Part 5.3.5.3, p. 166 and Part 6.2.1, p. 332

Exhibit B-9-1, Attachment BCUC IR 1.131.1b

Distribution Employees

"There were also ten additional planners and appointment setting employee positions added to the Operations Centre to support capital programs including third party alteration work, the hazard mitigation program and the inactive services program." (Exhibit B-1, p. 166)

71.1 Please provide an organizational chart for the Operations Centre

Response:

The organizational charts were provided in the FEU 2012-2013 RRA (Exhibit B-1), Volume 2 Appendices, Tab H, pages 9-11.

71.2 Please provide the job descriptions for the planners and appointment setting employees.

Response:

The various job descriptions for the planners and customer appointment setting employees (OSRs) are provided in Attachment 71.2. The FEVI positions are IBEW while the FEI positions are COPE. Attachment 71.2 contains 7 job descriptions including:

- Mains & Service Planner (FEVI);
- Planning & Design Technician (FEVI);
- Planning and Design Technologist;
- Planning and Design Technologist 1;
- Planning and Design Technologist 2;
- Planning and Design Workleader; and
- Operations Support Representative 1.

71.3 Using the same location breakdown as Attachment BCUC 1.131.1b, please prepare a schedule showing the number of planners by location from 2006-2011.

Response:

The following schedule provides the number of planners by location as requested.

BCUC 2.71.3 - Summary of Planners by Location - 2006 -2013

Regional Offices/Lower Mainland Musters and Offices	Cities and Towns serviced from Regional Office/Lower Mainland Musters and Offices	2006	2007	2008	2009	2010	2011	2012	2013
Burnaby Opns.	New Westminster, Vancouver, Burnaby, Whistler, Garabaldy Highlands, Squamish	5	0	0	0	4	5	5	5
Coquitlam	Port Moody, Port Coquitlam, Coquitlam	0	0	0	0	0	0	0	0
North Vancouver	West Vancouver, North Vancouver	0	0	0	0	0	0	0	0
Richmond	UBC Endowment Lands, Richmond	0	0	0	0	0	0	0	0
Total Metro		**5**	**0**	**0**	**0**	**4**	**5**	**5**	**5**
Albion	Maple Ridge, Pitt Meadows	0	0	0	0	0	0	0	0
Chilliwack	Cultus Lake, Hope, Kent, Chilliwack, Hope Unorganized	0	0	0	0	1	1	1	1
Abbotsford / Mission	Clearbrook, Abbotsford/Mission, Aldergrove	0	0	0	0	0	1	1	1
Goudy	Delta	0	0	0	0	0	0	0	0
Langley	Langley District, Langley	0	0	0	0	0	0	0	0
Roebuck	Surrey	0	0	0	0	0	0	0	0
Sunnyside	White Rock	0	0	0	0	0	0	0	0
Surrey Operations		41	46	45	46	40	43	46	49
Total Fraser Valley		**41**	**46**	**45**	**46**	**41**	**44**	**48**	**51**
Victoria	Central Saanich, Colwood, Esquimalt, Langford, Metchosin, North Saanich, Oak Bay, Saanich, Sidney, Sooke, Victoria, View Royal, Highlands	3	4	4	4	4	5	5	5
Nanaimo	Chemainus, Crofton, Duncan, Ladysmith, Lantzville, Nanaimo, North Cowichan, Parksville, Qualicum, Nanoose Bay	2	2	2	2	2	3	3	3
Courtenay	Comox, Comox District, Comox Reserve,Courtenay, Cumberland,Lazo,Puntledge Reserve	0	0	0	0	0	0	0	0
Total Vancouver Island (FEVI)		**5**	**6**	**6**	**6**	**6**	**8**	**8**	**8**
Prince George	Prince George , Shelley, Hixon	1	1	1	1	2	2	2	2
Kamloops	Chase, Kamloops, Logan Lake, Savona	2	2	2	2	2	2	2	2
Kelowna	Kelowna, Lakeview Heights, Peachland, Westbank,Winfield,District of Lake Country	3	3	3	2	2	2	2	2
Penticton	Penticton, Summerland,Okanagan Falls, Naramata, Keremeos	0	0	0	0	1	1	1	1
Cranbrook	Cranbrook, Kimberley	1	1	1	1	1	1	1	1
Trail	Trail, Warfield, Salmo, Rossland	1	1	1	2	1	1	1	1
Vernon	Vernon, Spallumcheen, Lumby, Grindrod, Falkland, Enderby, Coldstream, Armstrong	0	0	2	2	2	2	2	2
Total Interior		**8**	**8**	**10**	**10**	**11**	**11**	**11**	**11**
Total FEU		**59**	**60**	**61**	**62**	**62**	**69**	**72**	**75**

71.4 Modify Table 6.2-1 show Distribution Capital Expenditures from 2006 to 2013 and the number of Construction Planners and Appointment Employees using the format below. Also provide the table in fully functional electronic format.

	2010 Approved
Sustainment Capital	
Distribution System Reinforcements / Integrity and Reliabililty	7,900
Distribution Mains and Service Renewals and Alterations Growth Capital	10,060
Total Distribution Sustainment	17,960
Growth Capital	
New Customer Mains	8,807
New Customer Services	14,722
New Customer Meters	1,588
Total Distribution Growth	25,117
Total Distribution	43,077
# of Construction Planners	
# of Appointment Setting Employees	

Response:

The modified version of Table 6.2-1 (page 332 of Exhibit B-1) Mainland Distribution Capital Expenditures from 2006-2013, together with the number of Planners and Customer Appointment Setting Employees is provided in Attachment 71.4 in fully functional electronic format. The FEVI Planner headcount (included in the response to BCUC IR 2.71.3) has been excluded from the Construction Planner count in Attachment 71.4 as these employees are primarily engaged in supporting FEVI Distribution Capital Expenditures.

The Mainland Meter Recalls/Exchanges capital dollars have also been included in the Distribution Sustainment Capital category as this work, in addition to the hazards mitigation program, is typically scheduled by the Customer Appointment Setting group. The Customer Appointment Setting ("CAS") group fluctuates from 5 to 12 employees monthly with fluctuations in the fulltime equivalent (FTEs) number as well depending on the level and cycle of activities within a given year. The function of the CAS group is to schedule customer appointments for meter exchange, difficult to access locations for leak survey and hazard remediation work (i.e. installing a protection post or performing a regulator upgrade). CAS appointments are a blend of O&M and capital work. The number of full time equivalents has been included in Attachment 71.4.

The number of customer appointment setters has increased since 2008 due to an increase in the number of meter exchanges and the expansion of the hazard remediation program and inactive service removal activities in 2010. The reduced forecast for 2012 and 2013 is related to the transfer of meter exchange appointments to the Customer Contact centres in 2012.

72.0 Reference: Appendices

Exhibit B-9, BCUC IR 133.1, p. 436

O&M Resource costs – Separating Customer Service

"The requested working spreadsheets are provided in Attachment 133.1."

The Customer Service only costs in spreadsheet 1.133.1b show the total costs are up 9.56% for 2011. This appears to be reflective of labour up 24%, fees & administration down in 2010 but then up 55% in 2011, and recoveries up in 2010 and then down in 2011.

72.1 Please expand on the reasons for the 9.56% increase in 2011, including the relationship to the in-sourcing project. The response may be best represented by a concise summary of the various materials in different locations of Exhibit B-1.

Response:

Upon further review, an error has come to light in the calculation of the 2010 capitalized overhead provided in Attachment 133.1 to the response to BCUC IR 1.133.1 (Exhibit B-9), wherein the actual capitalized overhead amount for 2010 should read $8,201 thousand at an approved rate of 14 percent. As a result, the 2010 Total Net O&M expenses for Customer Service after capitalized overhead should read $50,376 thousand, as shown in the revised table below, representing a 7.02 percent increase from 2010 actuals to 2011 projection. This 2011 projection is consistent with the expenditures in the approved Negotiated Settlement Agreement for the 2010-2011 RRA.

This 7.02 percent difference between the 2010 actuals and the 2011 projection can be accounted for in three main areas of costs: Contractor costs, Fees and Administration and Labour costs. Each is described in detail below.

1. Contractor costs show an increase of $1.1 million from the 2010 actual O&M to the 2011 projected O&M in the table below, of which $0.6 million is due to CWLP contract inflation of 0.9% and $0.5 million corresponds to customer additions to the contract from one year to the next.
2. Fees and Administration costs show an increase of $2.5 million from 2010 actual O&M to 2011 projected O&M in the table below, primarily due to the difference in bad debt expense, with the 2011 bad debt expense being equal to the approved amount. The 2010 bad debt expense was lower than the 2010 approved budget due to low gas

commodity costs coupled with warmer winter weather which translated into reduced throughput in 2010. At the current time, there are no indications that 2011 bad debts will be at the same level as those experienced in 2010, but there are early indications that the 2011 bad debts will be lower than the 2011 approved budget and thereby impact the initial 2011 O&M projection provided in the Application. The aging balance levels for gas consumption are lower than was assumed when the budget was prepared and as a result the FEU expect bad debt expense to be lower by $0.4 million. The RRA filing and associated schedules have not been updated to reflect this revised projection as it is has no impact on the determination of rates for 2012 or 2013.

3. Labour costs show an increase of $0.5 million from 2010 actual O&M to 2011 projected O&M as shown in the table below. This difference is due to the transfer of budget funds from other departments to provide for a standalone Customer Service department, necessary to oversee the new (in-sourced) Customer Service of $0.3 million, and labour inflation for existing staffing levels along with the filling of roles that had remained vacant throughout various periods of the year in 2010 for a total of $0.2 million. The reallocation of dollars for the standalone Customer Service department resulted in a corresponding reduction of budgets in other departments. The 2011 projected spend is representative of the approved spend as per the NSP for the 2010-2011 RRA.

The 2011 Projected spend shown in the table below is the approved amount as per the Negotiated Settlement Agreement for the 2010-2011 RRA and any in-sourcing project charges are appropriately charged directly to the CCE Project and not included in O&M forecasts.

FORTISBC ENERGY UTILITIES
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW - CUSTOMER SERVICE DEPARTMENT ONLY
($000)

Line No.	Particulars	2006	2007	2008	2009	2010	Projection 2011*	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	M&E Costs	$ 991	$ 850	$ 838	$ 1,107	$ 1,301	$ 1,647	$ 8,116	$ 8,163
2	COPE Costs	$ 518	$ 424	$ 481	$ 748	794	945	1,946	1,953
3	COPE Customer Services Costs	$ -	$ -	$ -	$ -	-	-	11,824	11,177
4	IBEW Costs	$ 196	$ 2	$ 1	$ 1	-	-	-	-
5									
6	**Labour Costs**	**1,705**	**1,276**	**1,320**	**1,855**	**2,095**	**2,592**	**21,885**	**21,294**
7									
8	Vehicle Costs	$ 15	$ 0	$ 0	$ 0	0	-	-	-
9	Employee Expenses	$ 78	$ 49	$ 69	$ 83	94	89	544	533
10	Materials and Supplies	$ 17	$ 5	$ 4	$ 8	8	7	266	317
11	Office Furnishing & Equipment	$ -	$ -	$ -	$ -	-	0	0	0
12	Computer Costs	$ 7	$ 16	$ 30	$ 12	28	6	2,422	2,497
13	Fees and Administration Costs	$ 8,101	$ 6,433	$ 6,413	$ 6,334	4,447	6,901	34,959	39,396
14	Contractor Costs	$ 48,463	$ 49,765	$ 51,169	$ 51,408	53,335	54,405	5,706	6,045
15	Facilities	$ 8	$ 5	$ 5	$ 8	85	97	2,761	2,762
16	Recoveries & Revenue	$ (2,654)	$ (1,958)	$ (1,713)	$ (1,393)	(1,515)	(1,428)	(7,753)	(8,131)
17									
18	**Non-Labour Costs**	**54,035**	**54,316**	**55,977**	**56,461**	**56,482**	**60,077**	**38,906**	**43,419**
19									
20	**Total Gross O&M Expenses**	**55,740**	**55,592**	**57,297**	**58,316**	**58,577**	**62,668**	**60,791**	**64,712**
21									
22	Add: Shared Corporate Services								
23	Add: PST Savings						18		
24	Less: O&M Difference from Allowed								
25	Less: Vehicle Lease Reclass								
26	Less: Capitalized Overhead	(8,918)	(8,895)	(9,167)	(9,331)	(8,201)	(8,776)	(8,511)	(9,060)
27									
28	**Total O&M Expenses**	**$ 46,822**	**$ 46,698**	**$ 48,129**	**$ 48,986**	**$ 50,376**	**$ 53,910**	**$ 52,280**	**$ 55,653**
						(0)		0	0

Shared Services fees incurred are included on line 13 Fees and Administration Costs while the Shared Services recoveries are shown on line 16 Recoveries & Revenue.

*For the purposes of this report the PST savings have been excluded from the resource categories and have been shown on a separate line instead. Including the PST savings the total 2011 Projection is $62,686 thousand.

The costs excluding Customer Service in spreadsheet 1.133.c show the total costs are up 15.25% for 2010, even though the 2010 Actual is less than the 2010 Approved. The main resource items that increased in 2010 are Labour, Employee Expenses, Computer Costs, and Fees/Administration. In 2011, the Employee Expenses and Fees/Administration decreased significantly.

72.2 Please expand on the reasons for the 15.25% increase in 2010, and then the decrease in those non-labour costs in 2011. The response may be best represented by a concise summary of the various materials in different locations of Exhibit B-1.

Response:

Following the first round of IR responses, the FEU filed an evidentiary update on July 19, 2011 that amongst other things included updates to the O&M forecast. The July 19th Evidentiary Update schedules reflect the O&M changes filed as part of that update. In addition, the capitalized overhead error identified in response to BCUC IR 2.72.1 had impacted the Combined_Resource_View_No_CSD schedule (please refer to BCUC 2.72.1). Also, Shared Services recoveries formerly shown on line 16 Recoveries & Revenue have now been offset against Fees and Administration Costs to eliminate Shared Services between the FEU utilities. The Combined_Resource_View_No_CSD schedule included below has been corrected for the capitalized overhead error and change in recoveries presentation. As a result, the 2010 Total Net O&M Expenses excluding Customer Service after capitalized overhead should read $155,431 thousand as shown in the revised table below, representing a 14.39% increase from 2009 to 2010 actuals.

The 14.39% increase in 2010 totalling approximately $19.6 million consists largely of the following:

- $6.9 million (an increase of 7.3% in this category) is attributed to Total Labour. The increase is mainly due to increased headcount (2010 average FTEs increased by 80 or 6.3%), general labour inflation and benefits, and executive retirement costs of about $2.6 million.
- $1.6 million (an increase of 33.8% in this category) is due to Employee Expenses. About one quarter of the increase can be attributed to headcount increases and basic inflation. Labour cost increased by 7.3% in 2010 and a similar increase would apply to Employee Expenses related to new hires. The remaining three quarters of the increase is due to additional employee training. Approximately $500 thousand is due to changes to accounting standards, where employee training that was allocated to capital projects

in 2009 is now charged to O&M in 2010. As a result of Demographic challenges in 2010, additional training of new hires was undertaken to replace retiring long term employees. Also, additional training was required to educate employees with respect to changes in Government Policy, changes in Codes and Regulations, and changes in Accounting Standards.

- $2.3 million (an increase of 27.9% in this category) is attributable to Computer Costs. About 45% of the increase was due to accounting changes, where certain costs that have been historically capitalized are now required to be expensed. The remaining 55% can be attributed to computer costs incurred in connection with IT contract increases, the BC One Call project, and miscellaneous computer costs.

- $6.7 million (an increase of 29.9% in this category) is attributable to Fees and Administration Costs. The following items contributed to the $6.7 million increase in 2010:

  - Corporate Services allocation from FHI accounted for about $1.7 million of the increase.

  - Approximately $890 thousand can be attributed primarily to public safety messaging, increased media coverage, and various communications.

  - About $743 thousand was incurred in 2010 to support the corporate rebranding initiative.

  - The remaining $3.4 million can be explained by increases in O&M costs for items such as: BCUC assessments, PST adjustments coded to Fees and Administration (offsets in other lines), shared services with FortisBC Inc, increases in audit fees, membership dues and other miscellaneous items.

In 2011, Employee Expenses and Fees and Administration Costs decrease by $1.7 million or 26.8% and $3.2 million or 8.7% respectively. The projected decrease in these items in 2011 is mainly due to the higher level of expenses experienced in 2010 as described above.

FORTISBC ENERGY INC (COMBINED)
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW - EXCLUDING CUSTOMER SERVICE DEPARTMENT
($000)

Line No.	Particulars	2006	2007	2008	2009	2010	Projection 2011*	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	M&E Costs	$ 39,321	$ 42,842	$ 41,134	$ 42,920	$ 45,750	$ 50,669	$ 57,736	$ 58,359
2	COPE Costs	22,073	21,650	22,653	24,930	27,923	30,292	34,187	36,178
3	COPE Customer Services Costs	-	-	-	-	-	-	0	0
4	IBEW Costs	24,232	24,591	25,760	26,630	27,748	30,839	33,159	34,931
5									
6	**Labour Costs**	**85,626**	**89,083**	**89,546**	**94,480**	**101,421**	**111,800**	**125,082**	**129,468**
7									
8	Vehicle Costs	4,856	5,361	5,626	5,516	4,312	4,045	4,484	4,544
9	Employee Expenses	3,758	3,912	4,785	4,694	6,281	4,599	5,628	5,818
10	Materials and Supplies	5,004	5,551	6,840	7,115	7,870	6,587	7,851	8,173
11	Office Furnishing & Equipment	47	-	-	-	19	-	-	-
12	Computer Costs	8,937	8,005	7,860	8,405	10,745	11,118	12,312	12,809
13	Fees and Administration Costs	29,647	23,318	25,386	22,508	29,243	25,729	29,192	30,225
14	Contractor Costs	9,300	9,403	11,315	13,398	15,326	15,402	18,214	20,342
15	Facilities	12,509	13,399	13,157	14,219	15,080	15,447	15,749	13,581
16	Recoveries & Revenue	(9,053)	(8,512)	(8,644)	(8,617)	(10,936)	(9,063)	(11,098)	(10,286)
17									
18	**Non-Labour Costs**	**65,005**	**60,439**	**66,324**	**67,237**	**77,940**	**73,865**	**82,333**	**85,205**
19									
20	**Total Gross O&M Expenses**	**150,631**	**149,522**	**155,870**	**161,717**	**179,361**	**185,665**	**207,414**	**214,673**
21									
22	Add: Shared Corporate Services	0	0	0	0	0	0	0	0
23	Add: PST Savings	0	0	0	0	0	712	0	0
24	Less: O&M Difference from Allowed	-	-	-	-	1,379	-	-	-
25	Less: Vehicle Lease Reclass	(2,100)	(2,008)	(1,988)	(1,804)	-	-	-	-
26	Less: Capitalized Overhead	(23,116)	(23,575)	(23,551)	(24,034)	(25,309)	(26,081)	(29,038)	(30,054)
27									
28	**Total O&M Expenses**	**$ 125,415**	**$ 123,940**	**$ 130,332**	**$ 135,879**	**$ 155,431**	**$ 160,295**	**$ 178,376**	**$ 184,618**

73.0 Reference: Asset Retirement Losses

Exhibit B-9, BCUC IR 1.148.1

FEU states that "This issue was not detected earlier as at that time, the reported "losses" appeared appropriate given the noted retirement activity of the period. It was only when the "losses" continued over a longer period that the need for further investigation was apparent."

73.1 When was the need for further investigation apparent to FEU?

Response:

This response addresses the responses for BCUC IRs 2.73.1 through 2.73.3. Although the quoted preamble above was specifically describing the Regulator and Meter Installation asset class, the response to this IR is applicable to both this specific asset class and the other asset classes with significant unrecovered depreciation more generally.

The need for further detailed investigation of the loss balance was not apparent until during the recent 2010-2011 RRA proceedings.

The FEU have been following the BCUC approved regulatory treatment for retirement of assets. As such, the FEU expected that this loss balance would continue to grow until such time as depreciation rates could be implemented that would begin to recover these balances over the remaining lives of the associated assets, and then the balances would slowly begin to reverse. While there was no opportunity to adjust depreciation rates during the PBR period, the FEU proposed updated depreciation rates in the 2010-2011 RRA to begin to address the growing balances. Therefore, the FEU did not anticipate a requirement for detailed investigation into these balances until requested to do so by the Commission staff as part of the 2010-2011 RRA negotiated settlement process.

The FEU have made no attempt to keep information from the Commission. There was a process and methodology in place for ultimate recovery of the balances (representing the allowed return of capital for utility investments), the FEU were following the approved method to recover the balances, all asset removals were conducted for utility purposes and costs were prudently incurred. In the opinion of the FEU, there was no question as to recoverability of these amounts and no reason for concern to be raised with the Commission during the PBR period. As noted above, in the first revenue requirement after the PBR period, the FEU proposed new depreciation rates to begin to address the issue.

73.2 Was any investigation done before the 2010-2011 RRA? If so, why wasn't the results of this investigation provided during that proceeding?

Response:

Please see the response to BCUC IR 2.73.1.

73.3 At the point that investigation became apparent, why didn't FEU disclose, to the Commission, the size of this unrealized loss balance in either the annual regulatory reporting document or through the past RRA applications? Why did the BCUC learn of this matter through information requests?

Response:

Please see the response to BCUC IR 2.73.1.

74.0 Reference: Asset Retirement Losses

Exhibit B-9, BCUC IR 1.148.4

74.1 Please provide the Accounting definition of a Loss?

Response:

Accounting textbooks generally define net income or net loss as the difference between the revenues and expenses; therefore a loss arises when expenses are greater than revenues.

In calculating a loss in the context of asset disposals, a loss generally arises when proceeds on disposal are less than an asset's current net book value. In the context of assets that are removed from service (as opposed to being sold), a loss (under-recovery of depreciation) would therefore arise any time an asset is retired prior to reaching a net book value of zero, and the loss would equal the net book value at the time (undepreciated value) net of any salvage value recoveries.

74.2 If FEU did not have regulatory consent to continue to capitalize un-depreciated amounts, would FEU be required, under generally accepted accounting principles, to record a "loss" upon disposal/retirement of any assets that were not fully amortized?

Response:

The FEU follow US generally accepted accounting principles (including ASC 980 Regulated Operations), as modified by Commission decision or direction.

For assets where the group accounting method is used, the FEU would not be required to record a "loss" upon disposal/retirement of any assets that were not fully amortized under generally accepted accounting principles. The group accounting method that results in assets continuing to be depreciated after they have been removed from service is acceptable under both generally accepted accounting principles (US GAAP) and regulatory treatment as set by Commission direction.

US GAAP:

Attachment 74.2 to this response includes, "Accounting for Property, Plant and Equipment, Asset Retirement Obligations and Depreciation" which was prepared by

PriceWaterhouseCoopers LLP and describes in detail the acceptability of group accounting procedures under US GAAP. Excerpts from that document include:

> *"The composite convention of accounting is an acceptable convention* ***regardless of whether an entity is subject to cost-of-service regulation****. As noted above, the composite or group convention was established as a means of simplifying the process of tracking a large asset system with many small components with small relative values compared to the larger composite group. As discussed in the following excerpts from Chapter 11 of Kieso, Weygandt, and Warfield's Intermediate Accounting Text (11th Edition), both of these conventions of accounting are considered acceptable conventions pursuant to GAAP.*
>
> > *Two methods of depreciating multiple-asset accounts are employed: the group method and the composite method. The term "group" refers to a collection of assets that are similar in nature. "Composite" refers to a collection of assets that are dissimilar in nature. The group method is frequently used when the assets are fairly homogeneous and have approximately the same useful lives. The composite approach is used when the assets are heterogeneous and have different lives. The group method more closely approximates a single-unit cost procedure because the dispersion from the average is not as great. The method of computation for group or composite is essentially the same: find an average and depreciate on that basis.*
> >
> > *The differences between the group or composite method and the single-unit depreciation method become accentuated when we look at asset retirements.* ***If an asset is retired before, or after, the average service life of the group is reached, the resulting gain or loss is buried in the Accumulated Depreciation account. This practice is justified because some assets will be retired before the average service life and others after the average life. For this reason, the debit to Accumulated Depreciation is the difference between original cost and cash received. No gain or loss on disposition is recorded****.*
> >
> > *The group or composite method simplifies the bookkeeping process and tends to average out errors caused by over-or under depreciation. As a result, periodic income is not distorted by gains or losses on disposals of assets."*
>
> *"We also believe that those businesses using the composite or group deprecation convention should regularly obtain updated depreciation studies (perhaps every 3 – 5 years), which is consistent with FERC regulations. The periodic update of depreciation*

rates is necessary to level actual incurred disposition gains or losses and is part of the underlying basis for the acceptability of these group accounting conventions." [Emphasis added]

<u>Commission Direction:</u>

The relevant Commission direction in this case is the BCUC Uniform System of Accounts as modified by subsequent Commission decisions. Under the Uniform System of Accounts, the FEU are required to capitalize un-depreciated amounts on asset removals to accumulated depreciation, as described below:

"When a plant unit is retired from gas operations the ledger value thereof shall be eliminated by crediting the appropriate plant accounts…If the plant being retired is classified as depreciable, the ledger value less the net salvage value and/or insurance, if any, recovered shall be charged to accumulated depreciation"." (Page 17)

"Ledger value is the amount at which property is carried in the plant account. In case the value of any portion of plant is not shown separately, the ledger value of that portion shall be its proportionate share of the value of the entire group in which the particular plant is included." (Page 17)

"The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group." (Page 24)

"When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization. Assets remaining in use after reaching the average life expectancy are not regarded as fully depreciated until actual retirement." (Page 25)

Subsequent to the direction provided in the Uniform System of Accounts, the FEU were later directed in their recent revenue requirement applications to record gains and losses on disposal of assets in a deferral account for future recovery from customers. The FEU followed that direction starting in 2010, and are proposing to continue that treatment for 2012 and 2013 with a 20 year amortization period for the deferral account.

Summary:

The FEU believe that the current practice of recording the gains and losses in a deferral account with recovery over 20 years appropriately balances the intention of the group system of accounting and the Uniform System of Accounts, with the benefit of providing an increased level of transparency into the trends in asset removals being experienced by the utilities.

74.3 What is the difference between, for accounting purposes, of a "loss" and "unrecovered depreciation"?

Response:

This is in response to BCUC IRs 2.74.3 and 2.74.4.

There is no real difference between the accounting **calculation** of a "loss" and "unrecovered depreciation". Rather, the distinction is helpful to avoid a mischaracterization as to the **nature** of the amounts under discussion.

Losses imply that there is an act on the part of the Companies, resulting in assets that still have a useful life being sold to a third party for a value that is less than their carrying value. In contrast, the unrecovered depreciation results from assets being removed from service earlier than the approved average life of the asset class, resulting in utility costs that have yet to be recovered from ratepayers. The Companies have made this differentiation to avoid any misunderstanding as to the nature of these amounts, and to reinforce that they represent the Companies' allowed return of investment in utility assets.

In the case of the FEU, regardless of whether these amounts are characterized as "losses" or "unrecovered depreciation", they represent amounts that are appropriately included in rate base and are fully recoverable from customers.

74.4 Does "unrecovered depreciation" imply that an amount is fully recoverable from a ratepayer?

Response:

Please see the response to BCUC IR 2.74.3.

74.5 Does FEU record depreciation for assets that are no longer in use? If so, how is this acceptable under generally accepted accounting principles?

Response:

The depreciation rates are intended to recover the accumulated losses (unrecovered depreciation) over the remaining service life of the asset class, and therefore, by design, some component of the rate can be attributed to assets that are no longer in use. The acceptability of this under generally accepted accounting principles is described in response to BCUC IR 2.74.2.

The use of averages is a necessary outcome of the average service life method of the group system of accounting, is generally accepted regulatory practice, and is in compliance with US GAAP. If the FEU were to discontinue this methodology, another methodology would need to be adopted. The single-unit cost procedure is not feasible due to the nature of the assets in question and, as FEI indicated in its 2010-2011 RRA on Page 488, the adoption of the equal life group methodology, which would be the alternative to the average service life methodology, would result in an increase in depreciation expense of approximately $15 million annually, resulting in a significant rate increase.

> *"An alternative depreciation methodology for adoption is the Equal Life Group ("ELG"). In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group. For purposes of determining an annual rate, the calculated depreciation amount is divided by the surviving balance of the group's cost.*
>
> *Both methods allocate the cost of the assets to the pattern of consumption by the utility's customers. The ELG method provides a more detailed breakdown of the components*

within each asset class and as such provides a much more detailed estimate of the depreciation. ***If the ELG method were adopted, the depreciation expense would be approximately $15 million higher than that calculated using the ASL.*** *From Terasen Gas' perspective, both depreciation methods are acceptable. Terasen Gas proposes the continuation of the ASL approach as it believes the ASL approach complies with IFRS requirements and helps to mitigate customer rate impact."*

The FEU continue to believe that the current regulatory average service life methodology is appropriate and provides benefits to customers over time as compared to other alternatives.

74.6 FEU indicates that many factors have contributed to the unrecorded losses and that they were aware of these losses and have incorporated these changes into the depreciation study. If all these changes were incorporated, why were asset recovery rates, even once including all requested but not approved depreciation rate changes, still insufficient to recover the useful lives of the assets?

Response:

Please see the response to BCUC IR 1.155.6, an excerpt of which has been provided below for ease of reference.

"The IR appears to assume that (1) there should be no under-recovered depreciation in the account and (2) that the recommended adjustments to depreciation rates would have entirely reversed the amount of "losses" over the 10 year period of 2000 to 2009. These are both incorrect assumptions as explained below:

1. *The amounts recorded as losses are a function of when FEI recovers depreciation from customers. Under the group accounting method, it is expected that some assets will be removed from service prior to the expected life of the asset group, and some assets will be removed from service after the expected life of the asset group. Therefore, the individual assets that are removed from service during the years prior to the average life of the asset class will more likely result in the recording of under-recovered depreciation. As the system ages, the trend will move towards individual assets being removed from service having over-recovered depreciation. That is, we should expect to record some under-*

recovered depreciation in the years prior to the average service life of the asset group.

2. *Recommendations for revised depreciation rates are not designed to recover existing "loss" balances all at once. Depreciation rates are designed to recover existing amounts of unrecovered depreciation over the remaining service lives of the assets that remain in the asset class. Therefore, it should not be expected that the recommended adjustments to depreciation rates would have entirely reversed the amount of unrecovered depreciation that was recorded over the 10 year period of 2000 to 2009.*

3. *Given that the asset classes involved in this analysis have an average life of approximately 40-50 years and therefore have not yet reached their average life expectancy, over the 10 year period of 2000 to 2009, we would expect less than 20 percent to 25 percent of the losses to be addressed through higher depreciation rates and that the remaining amounts would be recovered over the next 30 to 40 years."*

74.7 If the many factors that contributed to the unrealized losses are known to FEU, why is it difficult to perform the calculations to determine the impact of each factor? Is this a result of the significant amount of unrealized losses in general?

Response:

The FEU interpret the question as referring to the following excerpt from the response to BCUC IR 1.148.4:

"Third, the reasons for the under-recovery of depreciation are many, and the contribution of any one factor to the under-recovery is difficult to determine. Examples of some of the factors are changes in meter costs, an increase in urban redevelopment, and for one asset class there are indications that the unit costs used to determine the retirement cost were overstated. Even though the FEU are filing a report with this RRA summarizing the known factors and how they contribute to the accumulation of unrecovered depreciation, the FEU have been aware of these factors as they have evolved over the years, and have incorporated these changes in their depreciation studies."

The FEU did not state that the many factors are known; the statement was that there are many factors, of which some are known. For those factors which have contributed to the asset classes experiencing the majority of under-recovery of depreciation, the FEU have performed high level calculations to determine their impacts; this analysis was not affected by the size of the unrecovered depreciation balances. This information was provided in Exhibit B-1 Appendix E-3.

The FEU reiterates that depreciation rates are based on estimates only, developed to allocate the cost of assets over their service lives. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors beyond FEU's control that can influence assets' lives.

The fact that there are remaining book values when assets are retired indicates only that:

- We are following the approved average service life group accounting method that results in some assets being retired earlier than average; and
- That the historically approved depreciation rates have not recognized changes to asset lives that have occurred since the rates were implemented.

74.8 Is it not reasonable to expect that depreciation rates for fixed assets should adapt to changes in the asset environment as they occur?

Response:

It is reasonable to expect that depreciation rates for fixed assets should adapt to changes in the asset environment **over time**. This is consistent with the long-term nature of the assets, and the fact that individual changes may cancel each other out or be one-time or cyclical in nature, so that depreciation rates should only be adjusted to reflect more permanent changes in the environment. As noted in the response to BCUC IR 2.75.2, this is consistent with the three to five year recommended frequency for updating depreciation rates. Three to five years is sufficient in length to detect long term trends in changes to assets' service lives. Any shorter review interval may be unduly influenced by short term events and lead to unnecessary rate volatility.

In the past, where required depreciation changes caused significant rate pressure, the changes were not always reflected. An excerpt below from the response to BCUC IR 1.148.4 describes why those changes that were identified as permanent have not always been reflected in updated depreciation rates.

> *"Fifth, it is not within the discretion of FEU to increase depreciation rates without Commission approval and there has not always been an appetite to increase depreciation rates due to the impact on rates. As discussed in the response to BCUC IR 1.155.6, proposals to increase depreciation rates have not been implemented. In addition, during the PBR period, depreciation rates and accounting policies were generally set and could only be adjusted for "exogenous factors". Exogenous factors were defined as items beyond the Company's control that were allowed to be adjusted in rates. These factors were limited to judicial, legislative or administrative changes, orders or directions, catastrophic events, bypass or similar events, major seismic incidents, acts of war, terrorism or violence, changes in generally accepted accounting principles, standards and policies, changes in revenue requirements due to Commission directions."*

The FEU reiterates that depreciation rates are based on estimates only, developed to allocate the cost of assets over their service lives. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors beyond FEU's control that can influence assets' lives.

The fact that there are remaining book values when assets are retired indicates only that:

- We are following the approved average service life group accounting method that results in some assets being retired earlier than average; and
- That the historically approved depreciation rates have not recognized changes to asset lives that have occurred since the rates were implemented.

74.9 Is it possible that due to FEU's reliance on Gannett Fleming to perform depreciation studies, FEU's reaction to changes in the asset management environment were slow to occur?

Response:

As stated in response to BCUC IR 1.136.2, the development of depreciation rates for assets follows what is common industry practice for utilities, where utility staff work with an external depreciation specialist to determine rates. The FEU engage the depreciation specialist to review rates when they have an opportunity to update depreciation rates through a revenue requirement application, or where review of depreciation accounts indicates an update is required.

The FEU do not believe that their reaction to changes in the asset management environment was slow to occur. Over the years, the FEU have monitored for changes in the asset environment and followed a reasonable and prudent approach, where expenses were only incurred to conduct a depreciation study when the FEU were able to make changes to depreciation rates and reflect them in updated delivery rates.

74.10 Given the significant volume of assets and the dynamic changing asset management environment of BC Hydro, why has FEU incurred significant unrealized losses while BC Hydro has not?

Response:

As stated on Page 8-18 of BC Hydro's F2012-F2014 RRA filing,

> *"BC Hydro's current practice under CGAAP is to recognize gains and losses for assets that are tracked on an individual basis. For assets that are tracked on a pooled basis (for example, distribution poles, transformers and meters),* ***BC Hydro does not record any gains or losses*** *except when entire pools or a substantial portion of an asset pool is retired prior to being fully amortized."* [emphasis added]

The FEU have confirmed that BC Hydro does not record any accumulated losses (or gains) because when mass assets are physically retired, no entry of the retirement is made to the accounting records. The retired asset continues to be treated as though it is still in-service and subject to depreciation until it is fully depreciated by the end of its forecast useful life.

Given that BC Hydro does not record and recognize accumulated losses, the premise of the question is incorrect.

The BC Hydro approach continues to depreciate assets in rates until they are fully recovered whether or not they are still in service. The FEU approach recognizes the unrecovered depreciation on retirement that exists and then includes a charge in future rates to recover these assets, thereby ultimately recovering the costs in rates. The two approaches achieve the same end result, however the FEU approach is more transparent to what is actually occurring.

74.11 Did any changes to asset management and maintenance occur during 2000-2010 that may have reduced the useful lives of FEU assets?

Response:

From 2000-2010, with the exception of residential meter refurbishments discussed on page 6 of the Asset Loss Report included as Appendix E-3 in the 2012-2013 RRA, the FEU have not made changes to asset management and maintenance requirements that may have reduced the useful lives of the FEU's assets.

The FEU administer a preventive maintenance program designed to extend the life of assets while ensuring appropriate investment of maintenance resources. Regular preventive maintenance is performed on gas system assets to ensure safe and reliable delivery of gas to customers. Corrective maintenance is initiated when equipment fails and is identified as part of a regular preventive maintenance program. Adequate corrective maintenance resources, coupled with adequate preventive maintenance resources, are a critical aspect of asset management and programs designed to maximize the service life of the assets.

With regards to residential meters, their refurbishment had become uneconomical. As a result, to utilize the full value of the meters, the FEU have eliminated refurbishment activities and allowed the meters to remain in the field until such time they are replaced with a new meter.

74.12 As losses started to build, in 2001 and 2002, was there an aggressive plan to review asset depreciation rates as a result?

Response:

In its 2000 Annual Review, FEI highlighted the need to update its depreciation rates based on a study conducted by Gannett Fleming. However, concerns over the run-up in natural gas commodity prices in the fall of 2000 and the impact on customer rates led to a decision to postpone any depreciation changes to a future period. This decision ultimately led to postponement of any depreciation rate changes until 2004 at which time a few recommended changes were implemented.

FEI provides excerpts from filings dating back to the early 2000s referencing this issue and highlighting efforts undertaken by FEI and the Commission to address the matter.

BC Gas 2000 Annual Review

Tab 9
Page 4

BC Gas sought advice from with Commission Staff on a number of occasions to discuss the possible implementation of the depreciation study along with proposed mitigation strategies. In spite of the reduced impact after mitigation, it was felt that, given the recent large commodity-based rate increases, implementing the full depreciation study was not desirable at this time. Implementing a few of the recommended changes in 2001 was thought acceptable, including those for Meters, Meter Installations and Computer Software. BC Gas has identified a number of mitigation strategies that effectively offset the ultimate rate impact of implementing depreciation changes to Meters, Meter Installations and Computer Software.

BC Gas 2003 Revenue Requirement Application

Full Implementation

Full implementation of the recommended depreciation rates would increase the average depreciation rate for the Lower Mainland, Inland and Columbia Service Areas from 2.96% to 3.68%. Depreciation expense in BC Gas' cost of service would increase by $17.2 million. Since depreciation expense is not tax deductible, the Company's revenue requirement would increase by $27.5 million. In terms of rate impact, this constitutes a delivery margin increase of about 5.6% or a revenue increase of about 2.2%.

Past Applications

In 2000, the Gannett Fleming study was reviewed with Commission Staff and a summary of the study was circulated to interested parties. A BC Gas proposal for increases in some depreciation rates was included in the Annual Review of November 2000, but because of large commodity-related rate increases at that time, the proposal was not implemented. In the Revenue Requirement Application filed in 2001 BC Gas sought to implement, effective January 1, 2002, changes in the depreciation rates for Meter, Meter Installations and Regulators, and Computer Software. That Application was later withdrawn.

Application in 2004

BC Gas believes it is now appropriate to implement increases in the accounts mentioned above in 2004. Accordingly, the 2004-2007 depreciation expense in this Application reflects changes to the depreciation rates for Meters, Meter Installations and Regulators, and Computer Software.

74.13 Under the fourth Factor, FEU describes group accounting as a method of accounting that should be expected to result in a buildup in unrecovered depreciation. Based on the survivor curves and the average useful life of assets, please complete the following table to demonstrate how and when the losses should end and gains should begin:

Expected losses (based on average service life, asset values and consideration of survivor curves)

Year	unrealized loss/(gain) expectation	net unrealized loss/(gain)
2012		
2013, etc.		
	Total	$0

Response:

There are a number of challenges to be able to fully respond to this question.

First, an estimate is required of the future retirement activity, by age of the investment being retired for each account through to the end of the expected maximum life of the investment. Given the long life expectation of a number of the accounts, this would include projections of the expected retirement amounts for approximately 120 years. As indicated in the plots of the Iowa curves included in Section VI of the Gannett Fleming depreciation study (Appendix E-1 of Exhibit B-1) the maximum life expectancy of a number of the accounts are near to, or exceed 100 years.

Second, given that the plant currently installed in many accounts was originally placed into service in the late 1950's, over 50 vintages of plant would need to be considered, as each vintage is at a unique current age and will have a unique retirement profile in each forecast transaction year. As such the determination of the annual retirement amounts could consider over 6,000 individual calculations.

Finally, each of these individual calculations would then require a separate determination of the gain or loss associated with the projected retirement. Given the complexity and number of calculations, a full response for each account cannot be completed in a timely fashion.

However, in order to be responsive and provide an indication of the trends of the future gain and loss amounts, FEI has requested that Gannett Fleming complete an analysis associated with the Account 475 Distribution Systems – Mains, representing a significant amount of investment and an asset class that has recorded retirement losses.

In completing the assessment for Account 475, Gannett Fleming included the following assumptions in order to simplify the model as much as possible:

- All future retirements have been estimated to occur exactly in accordance with the recommended Iowa curve;

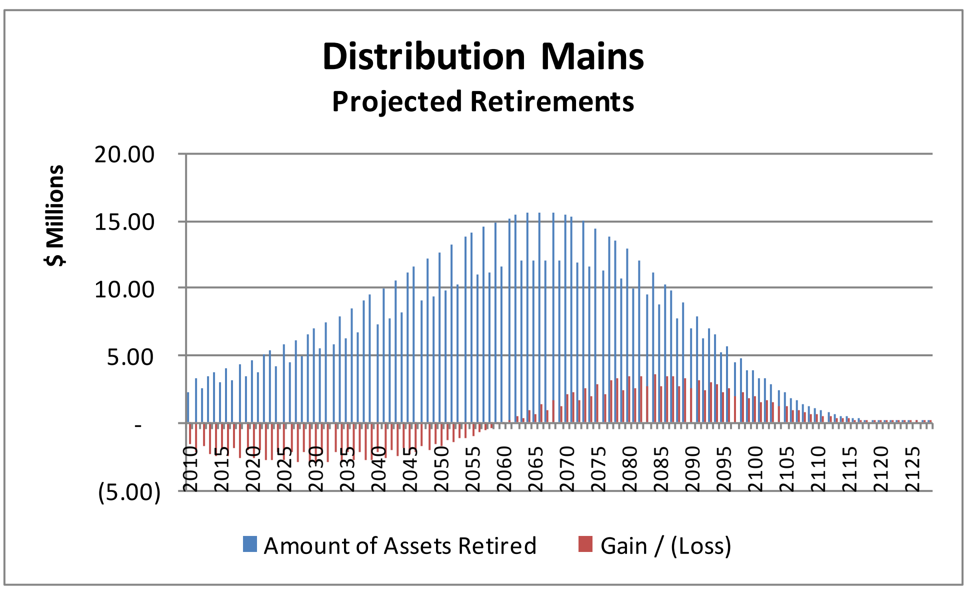
- All net salvage considerations were removed from the gains and losses determination;

- The current amount of accumulated depreciation variance was not amortized through any type of true mechanism. As such, at the end of the calculations made for Account 475, a small amount (less than $3 million) of accumulated depreciation surplus still exist but is immaterial to the analysis provided.

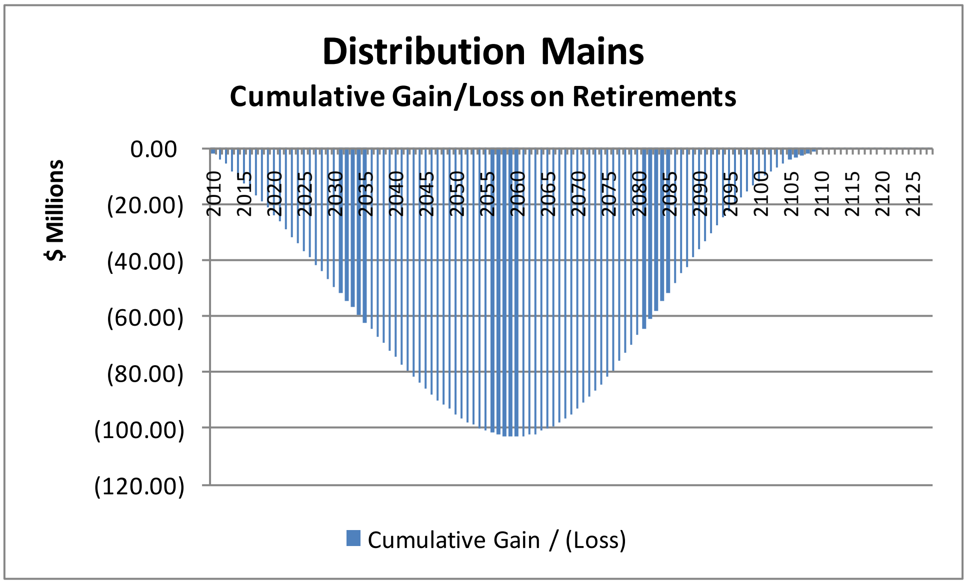
- No future capital additions are made to the account, resulting in an analysis of the current investment as at December 31, 2009.

For illustrative purposes, below is a graph showing the estimated annual and cumulative gains and losses through the year 2128. These amounts would be considered as normal and are required to be charged to the accumulated depreciation account in order to fully and accurately depreciate the current investment in Account 475. As noted above, the small amount of net gain at the end of 2128 is a function of the assumption to not amortize the accumulated depreciation variance that existed as at December 31, 2009.

As indicated on the graph below, losses are expected to continue until approximately the year 2060 at which time, based on the modelled assumptions and average estimated life, retirements of distribution mains are expected to lead to gains.



Over the asset life profile, the retirement losses and gains are expected to net out to zero.



74.14 In the Fifth reason to support customer recovery of losses, FEU indicates that "during the PBR period, depreciation rates and accounting policies were generally set and could only be adjusted for "exogenous factors." Exogenous factors were defined as items beyond the Company's control that were allowed to be adjusted in rates.

74.14.1 Does FEU believe that parties to the PBR expected that FEU had some degree of "control" over the useful lives of assets such as by frequency of usage of maintenance and that is why changes to the depreciation rates was not defined as "exogenous"?

Response:

This response is for BCUC IR 2.74.14.1 through 2.74.14.3.

The Multi-Year Performance-Based Rate Plan to Set Rates for 2004-2008 was approved by Commission Order No. G-51-03 through a Negotiated Settlement Agreement. An excerpt from that agreement follows:

"Regulatory Accounting Methodologies

Page C-19 proposes the continuation of GCRA/RSAM accounts, taxes payable method for income taxes, regulatory treatment for CPCNs from the 1998-2001 PBR Plan, accounting for certain assets and rate stabilization accounts on a net of tax basis, accounting for property, plant and equipment to include overhead and AFUDC. ***Approved depreciation rates are used. The current accounting treatment of property, plant and equipment retirements will continue****."* [emphasis added]

Since the rate setting methodology for the PBR period was set through a negotiated settlement process, the FEU cannot speculate as to why changes to depreciation rates were not defined as "exogenous". The FEU can confirm that depreciation rates did not change for any asset classes during the PBR period, as agreed to in the negotiated settlement.

Since it was known that the depreciation rates were not subject to change during the PBR period, and the group accounting treatment that results in gains and losses being recorded in accumulated depreciation and recovered over the average remaining service lives of the asset group was well known and accepted (both of these from the excerpt above), the FEU believe that the parties to the PBR knew or should have known that any difference between expected lives of assets and actual lives would be adjusted in future depreciation rates. Further, the factors including safety, reliability, customer initiated and economic that contributed to the shortened lives of the asset classes which have experienced the majority of the losses recorded (i.e. as described in Exhibit B-1 Appendix E-3) are not generally ones that are within the control of the FEU.

While asset maintenance frequency is within control of the FEU, as indicated in the response to BCUC IR 2.74.11, the FEU have not made changes to asset management and maintenance requirements during the past decade that may have reduced the useful lives of the FEU's assets.

74.14.2 Does FEU believe that participants in the PBR knew that ratepayers would be charged -after the PBR –for the costs associated with asset use during the PBR?

Response:

Please see response to BCUC IR 2.74.14.1.

74.14.3 Did some depreciation rates for certain asset classes change during the PBR?

Response:

Please see response to BCUC IR 2.74.14.1.

74.15 In the Sixth reason to support customer recovery of losses, FEU states "decisions and agreements not to increase depreciation rates were made based on the understanding that all unrecovered depreciation would be recovered from customers and that only the timing of recovery would be affected."

74.15.1 What evidence exists to support this statement?

Response:

This response addresses the responses to BCUC IRs 2.74.15.1 through 2.74.15.3.

The evidence for the statement includes the following:

1. The FEU were following the approved accounting treatment according to the Uniform System of Accounts and accepted by regulatory jurisdictions throughout Canada and the United States;

2. There was no allowance in the PBR agreement to adjust depreciation rates; and

3. The regulatory compact allows for the recovery of prudently incurred cost of service over time, and for the utility to earn a return of its investment.

Given the above, there was no other mechanism in place to reflect the changes to asset lives resulting from changes to the operating environment and safety considerations, except through future depreciation rates.

As discussed in response to BCUC IR 2.74.14.1, the participants to the PBR agreement were or should have been aware of the fact that depreciation rates were set for the PBR and therefore amounts that were not recovered due to factors that influence the asset lives would be recovered in future rates. Also as discussed in that response, the FEU cannot speculate as to why the depreciation rates were not considered exogenous under the PBR agreement, but it would make sense that there was no need to include changes to depreciation rates in the exogenous factor consideration when the depreciation rates were expected to be trued up in later years, as allowed for under the Uniform System of Accounts and accepted regulatory treatment throughout North America.

In addition, the fact that the recent depreciation study filed in the 2010-2011 RRA Application highlighted the need to address the growing accumulated depreciation deficiency built up in prior years and was approved by the Commission, provides support of the statement that "decisions and agreements not to increase depreciation rates were made based on the understanding that all unrecovered depreciation would be recovered from customers and that only the timing of recovery would be affected."

For reference, the FEU also provide a brief recap of the discussion in previous RRA Applications prior to the 2010-2011 Application which had highlighted the need to update the depreciation rates but for which the update was deferred or limited and which then contributed to the accumulated deficiency.

In 2000, FEI provided a study update but due to commodity-related increases the proposal was not implemented. In its 2004 – 2008 multi-year PBR Application, FEI sought and obtained depreciation rate changes for some assets. In its application for the extension of the 2004-2007 PBR to 2008 and 2009, FEI noted, "In extending the term of the existing settlement and as discussed with stakeholders, TGI is forgoing seeking changes to both depreciation and overheads capitalization rates which would increase cost of service and revenue requirements significantly beyond the levels anticipated under an extension." In its 2010-2011 Revenue Requirement Application, FEU sought and obtained approval for depreciation rate changes noting that the updated depreciation rates needed to be implemented "in order to reverse the trend of the growing accumulated depreciation deficiency that exists in most accounts." - Source: page 485 of FEI's 2010-2011 RRA Application.

In summary, the FEU had stated in its 2000 and 2004 Applications and its PBR Extension Application, the need to update its depreciation rates. The update to depreciation rates was deferred until the recent 2010-2011 RRA where they were proposed and approved in total by the Commission. This sequence of events provides evidence to the statement referenced in this question.

74.15.2 Did FEU communicate this to all participants during the PBR period?

Response:

Please see the response to BCUC IR 2.74.15.1.

74.15.3 If this was the case, then why wasn't depreciation considered an "exogenous factor" under the PBR agreement?

Response:

Please see the response to BCUC IR 2.74.15.1.

75.0 Reference: Asset Retirement Losses

Exhibit B-9, BCUC IR 1.151.5, IR 1.136.2

75.1 FEU notes the "unrecovered depreciation", which is the unrealized losses on asset retirement is primarily due to differences between the actual life of assets and estimated life of the asset."

75.2 Is a review of asset useful life every 3-4 years sufficient to detect changes in asset useful lives?

Response:

Please refer to page I-5 of the Gannett Fleming depreciation study included in Appendix E1 of the RRA Application (Exhibit B-1).

As noted in the depreciation study, the recommended interval for updating depreciation studies is every three to five years. Three to five years is sufficient in length to detect long term trends in changes to assets' service lives. Any shorter review interval may be unduly influenced by short term events and lead to unnecessary rate volatility.

75.3 Does management have any control over how long an asset is used by a utility such as by maintenance plans, workload on assets, plans to upgrade equipment or machinery, decision to repair or replace assets? What factors that determine when an asset is retired/replaced are outside of the utility's control?

Response:

The FEU answer this question as it relates to the asset classes where the majority of the losses have been recorded and where clarification is being requested as to management's control over the assets' useful lives. The assets classes include distribution mains and services and meters/install/regulators.

As noted in the response to BCUC IR 2.74.14.1, factors (including safety, reliability, customer initiated and economic) that contributed to the shortened lives of the noted assets classes are not generally ones that are within the control of the FEU.

75.4 Does FEU have any responsibility to accurately estimate depreciation rates for assets in use?

Response:

Please see the response to BCUC IR 2.75.5.

Yes, the FEU's goal is to estimate depreciation rates as accurately as reasonably possible and minimize the amount of any under-recovered or over-recovered depreciation that exists at the end of the assets' lives so that asset costs are distributed as fairly as possible to those customers that benefit from their use.

The FEU reiterate that depreciation rates are based on estimates only, developed to allocate the cost of assets over their service lives. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors beyond the FEU's control that can influence assets' lives.

The fact that there are remaining book values when assets are retired indicates only that:

- We are following the approved average service life group accounting method that results in some assets being retired earlier than average; and
- That the historically approved depreciation rates have not recognized changes to asset lives that have occurred since the rates were implemented.

75.5 If the ratepayer is fully responsible for any unrecorded losses due to things such as unrecovered depreciation, what incentive exists for management to i) properly maintain assets or ii) accurately estimate depreciation in the future?

Response:

Regardless of factors that ultimately affect the timing of recovery of assets over their estimated lives, management remains incented to i) maintain assets and ii) accurately estimate depreciation rates, as described below.

i. As discussed in the response to BCUC IR 2.74.11, the FEU's objective and incentive is to ensure safe and reliable delivery of gas to customers. To help achieve this, the FEU administers a preventive maintenance program designed to extend the life of assets while ensuring optimal investment of maintenance resources. Regular preventive maintenance is performed on gas system assets and maintenance is initiated when equipment fails and is identified as part of a regular preventive maintenance program. Adequate corrective maintenance resources, coupled with adequate preventive maintenance resources, are a critical aspect of asset management and programs designed to maximize the service life of the assets.

ii. As discussed in the response to BCUC IR 1.136.2, the FEU believe the process used to develop depreciation rates for its assets is reasonable and follow what is common industry practice, where utility staff work with an external depreciation specialist to determine the rates. Through the combination of external expertise and internal review and verification, depreciation rates are developed that best represent the conditions and assumptions known at the time. The final check in the process is all depreciation rate changes must be approved by the Commission prior to their implementation. In doing this, the FEU's goal is to estimate depreciation rates as accurately as possible and minimize the amount of under-recovered or over-recovered depreciation so that asset costs are distributed as fairly as possible to those customers that benefit from their use.

The FEU reiterate that depreciation rates are based on estimates only, developed to allocate the cost of a class of assets over the service life of that asset class. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors beyond FEU's control that can influence assets' lives. The fact that there are remaining book values when assets are retired indicates only that:

- We are following the approved average service life group accounting method that results in some assets being retired earlier than average; and
- That the historically approved depreciation rates have not recognized changes to asset lives that have occurred since the rates were implemented.

75.6 If, in the forecasting process, management estimates an expense for revenue requirements purposes and the actual cost varies from that estimate, the utility is not typically able to recover that cost unless an unexpected event occurs that is outside of the utility's control.

75.6.1 Why should depreciation be treated any differently?

Response:

This IR responds to BCUC IRs 2.75.6.1 and 2.75.6.2.

To address these questions, it is important to have clarity on the applicable definitions of Depreciation. From an accounting perspective, Depreciation represents the decline in the service value of assets. In addition, from a regulatory perspective, Depreciation represents a return of capital for the cost of investment in assets by the FEU.

The FEU forecast depreciation expense based on approved depreciation rates, and forecasts of the opening plant balances, plant additions and retirements. If the amount of actual depreciation expense differs from the forecast, the utility is not able to recover that difference. This is the same treatment as the majority of other forecast items.

However, for losses due to unrecovered depreciation the circumstances are different. In forecasting the depreciation rate (as opposed to the depreciation expense), the amount to be recovered is known (the prudently incurred cost of the asset). FEU is entitled to receive a return of that capital for investments it has made to serve its customers. The only question is the period of time over which that capital will be recovered. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors that can influence assets' lives which the FEU have limited ability to influence, and that result in under-recovered or over-recovered depreciation at any point in time. The existence of these balances is a result of the use of the approved average service life method of calculating depreciation rates, the changes in the external environment that influence the period of time that assets are in use, and the period of time since depreciation rates were last adjusted. Regardless of the depreciation rate that is forecast, approved and implemented, the utility is still entitled to an opportunity to receive the return of its investment in assets over time.

75.6.2 Why should losses on asset disposal, such as unrecovered depreciation, be treated any differently?

Response:

Please see the response to BCUC IR 2.75.6.1.

76.0 Reference: Asset Retirement Losses

Exhibit B-9, BCUC IR 1.155.2

76.1 If FEU experiences a gain on the retirement or disposal of depreciable property, does FEU believe that all gain should be fully realized by ratepayers?

Response:

The FEU believe they should continue to follow past practice, which is accepted by regulatory jurisdictions throughout Canada and the United States. That is, both underrecovered depreciation (losses) and overrecovered depreciation (gains) are recorded in accumulated depreciation, or in the case of the FEU for 2010 forward, in a deferral account. FEI notes that within accumulated depreciation at the end of 2009, 14 asset classes had accumulated gains (overrecovered depreciation) that are being returned to customers over time. These balances of overrecovered depreciation along with any other similar amounts recognized on removal of depreciable property in the future in the ordinary course of business would be fully returned to ratepayers.

76.2 Should the Commission find that the unrealized losses can be recovered from ratepayers based on FEU's position that all gains from the disposal/retirement of a depreciable asset would be realized by ratepayers, what mechanisms might be used to provide ensure that FEU does not change its position at a future date?

Response:

The FEU have not changed their position in the past, maintaining that gains and losses (representing over-recovered or under-recovered depreciation) on depreciable property that result from ongoing operations are fully returned to or recoverable from ratepayers, and do not anticipate changing those positions in the future. Disposals of property outside of the normal course of operations will continue to be the subject of separate regulatory applications to the Commission.

76.3 Does FEU believe that estimating asset usage (through depreciation rates) for the purposes of the RRA is not forecasting?

Response:

Please see the response to BCUC IR 2.75.6.1.

Recognizing that depreciation represents a return of capital which the utility is entitled to for investments made to serve customers, the FEU believe it should not be at risk for any forecast error in estimating the service life of its assets through depreciation rates. The FEU base their depreciation rates on estimates developed to allocate the cost of assets over their service lives. While prudent steps are taken to ensure the estimates are as reasonably accurate as possible, there are many factors that can influence assets' lives which the FEU have limited ability to influence.

77.0 Reference: Asset Loss Report

Exhibit B-9, BCUC IR 1.153.1

Asset Loss - Service Lines

"The FEU clarify that the data included in the Application (Exhibit B-1), Appendix E, Table E3-2 includes only costs and activities related to service abandonments which may originate as a result of customers redeveloping their property and demolishing existing buildings. As Section 10.13 relates to service alterations (i.e. relocations), the requirement to charge the customer would not apply to service abandonments."

77.1 Should FEU's GT&C be revised to charge customers for "costs and activities related to service abandonments which may originate as a result of customers redeveloping their property and demolishing existing buildings?" If not, why not?

<u>Response:</u>

No, the FEU's GT&Cs should not be revised to charge customers for costs and services related to service abandonments as abandoning a service line in an expeditious and safe manner is important to the continued safety of the delivery system and the public. Any disincentive such as that requiring a customer to pay for abandoning a service line may encourage actions that compromise the safety of the gas delivery system and also jeopardize the safety of the public. In addition, by charging a customer for the abandonment work, another level of complexity will be required to administer the process, potentially delaying the performance of the abandonment work required. As such, the FEU believe the costs of abandoning service lines should be borne by all customers, instead of just those requiring service lines to be abandoned. The FEU believe that the existing GT&Cs appropriately address the needs of its customers with respect to service abandonments and therefore, no revisions are required.

The FEU note that its practice of not charging customers for service abandonments is consistent with other Canadian natural gas utilities (e.g., Gaz Metro, Enbridge Gas Distribution, Enbridge Gas New Brunswick, AltaGas, Heritage Gas) terms and conditions with respect to service abandonments.

78.0 Reference: Bill Impact and Tariff

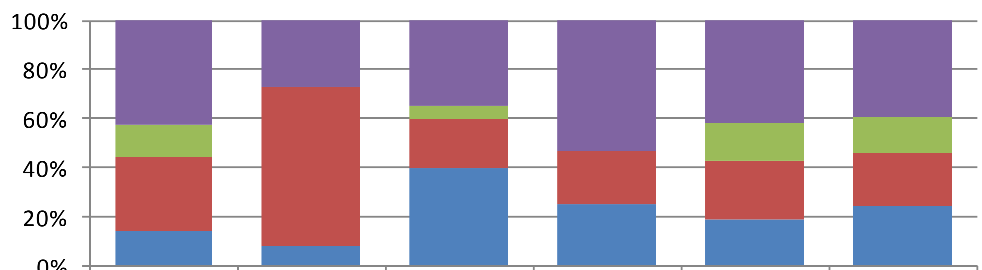
Exhibit B-9, BCUC IR 1.156.1

78.1 In reference to the graphs displayed on page 562, please compare FEI's percentage breakdown of the four components of costs billed to customers to at least 5 other gas providers in Canada.

<u>Response:</u>

The requested information is provided below. FEI notes that its combined delivery/basic charge component is approximately the same, or below, the percentage of the other five referenced utilities.

Natural Gas Cost Component Breakdown - Canada



	FEI	Pacific Northern Gas (West)	AltaGas	SaskEnergy	Manitoba Hydro	Enbridge
Cost of Gas ($/GJ)	43%	27%	35%	53%	42%	39%
Midstream Charge ($/GJ)	13%	0%	6%	0%	15%	15%
Delivery Charge ($/GJ)	31%	65%	20%	22%	24%	22%
Basic Charge	14%	8%	40%	25%	19%	24%

<u>Assumptions:</u>

1) The rates shown exclude riders (except where a rider is a direct Midstream/Commodity or Delivery Charge), taxes and any other fees (e.g. Carbon Tax) but include approved rate adjustments by respective Regulatory agencies.

2) All the rates are effective August 1, 2011.

3) Average Consumption per year is assumed to be 95GJ/year for all utilities.

4) Where appropriate, $/m^3 charges are converted to $/GJ by dividing them by heating value of 0.03795 GJ/m^3.

5) For AltaGas:

   a. Daily Basic Charge was multiplied by 30.25 to reach a monthly equivalent.

   b. Third Party Transportation Charge is assumed equivalent to Midstream Charge.

6) For Manitoba Hydro: Transportation and Distribution Charges are assumed equivalent to Midstream and Delivery Charges respectively.

7) For Enbridge:

   a. Delivery Charge reflects the first tier delivery rate (first 30m^3).

   b. "Transportation to Enbridge" rider is assumed equivalent to Midstream Charge.

8) Pacific Northern Gas and SaskEnergy do not have Midstream Charge equivalents.

79.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.158.1

79.1 As FEU has chosen to undertake thermal energy activities which may or may not be activities of a regulated utility, please explain what policies, procedures and controls exist within FEU to ensure that potential thermal activities costs are <u>appropriately</u> allocated to and recovered from either regulated, isolated ratepayers or general natural gas ratepayers? Specifically explain how FEU ensures that there are no conflicts of interests, incentive compensation conflict or lack of understanding amongst employees of how to separate these costs?

<u>Response:</u>

All of the thermal energy activities that the FEU are choosing to undertake are regulated activities. The thermal energy activities of the FEU are being provided within the regulated public utility (FEI) as another distinct class of service. The Thermal Energy Services Deferral Account and overhead cost allocation methodology is described in Appendix G, Section 2.4 of Exhibit B-1, and the FEU employee timesheet completion practices have been put in place to ensure the appropriate allocation of costs between classes of service within the regulated public utility. The FEU's employees are trained and advised on how to complete time sheets and code expenses appropriately to ensure that costs are captured and allocated appropriately among the classes of service. The FEU do not have incentive compensation policies that would cause a conflict of interest for the appropriate allocation of costs between service classes.

79.2 What formal communication was made to all i)marketing departments and ii)accounting personal to clarify the difference between a regulated and non-regulated activity to ensure that thermal activities costs are appropriately accounted for? Please provide copies of this formal communication.

<u>Response:</u>

No formal communication was made to marketing or accounting personnel regarding regulated and non-regulated activity with regard to FEI's thermal energy services, nor was one necessary. The thermal energy activities of the FEU are being provided within the regulated public utility (FEI) as another distinct class of service and are regulated activities. Any time spent by FEU's employees would only be an allocation between two regulated classes of services. The FEU's employee timesheet completion practices have been put in place to ensure the appropriate allocation of costs between classes of service within the regulated public utility

79.3 What modifications were made to internal controls processes including job descriptions and process descriptions to ensure that potential alternative energy costs are identified, isolated, documented and properly accounted for at FEU? Please provide copies of these document both before and after these adjustments have been made.

Response:

No modifications to internal control processes, job or process descriptions were required to identify, isolate and ensure that alternative energy costs are properly accounted for. The FEU employee timesheet completion practices were already in place which ensures the appropriate allocation of costs between classes of service within the regulated public utility.

79.4 Is the documented cost allocation policy for thermal activities similar to that of transfer pricing methodologies? Please provide a copy of the formal FEU thermal activities cost allocation policies and procedures and describe when and who drafted, reviewed and approved this policy.

Response:

There is no documented policy within the FEU that governs cost allocation between classes of service (such as thermal energy services) within the regulated public utility, nor does the FEU believe one is needed. The cost allocation methodology for thermal energy activities that already exists is similar to the transfer pricing methodology except that the transfer pricing methodology applies to services provided by a regulated utility to a non-regulated affiliated company; thermal energy activities are regulated activities. The Thermal Energy Services Deferral Account and overhead cost allocation methodology described in Appendix G, Section 2.4 of Exhibit B-1, and the FEU's employee timesheet completion practices are in place to ensure the appropriate allocation of costs between classes of service within the regulated public utility. Timesheet completion practices did not have to change to accommodate thermal energy services within the FEU for direct charges.

79.5 Has FEU internal audit tested the identification, isolation, allocation or cost recording of potential thermal activities of FEU?

Response:

The FEU internal audit department has not specifically tested the identification, isolation and allocation of costs to thermal energy activities. Internal audit does a review of timesheets and the coding of timesheets and the compliance with the corporate code of conduct which all employees adhere to.

79.6 Who is ultimately responsible for the cost allocations of thermal activities within FEU? Who signs off on the cost allocations of all potential thermal activities of FEU?

Response:

Individual employees are responsible for ensuring that direct time is allocated to thermal energy activities. The FEU's employee timesheet completion practices are in place to ensure the appropriate allocation of costs between classes of service within the regulated public utility.

On the thermal energy side, the Director responsible reviews the monthly charges and allocations from the FEU for reasonableness.

79.7 Would FEU be willing to have cost allocation methodology of thermal activities reviewed by an independent third party in 2012? If not, please explain.

Response:

The FEU considered a third-party review of the allocation methodology but did not believe the possible incremental benefit of an external study relative to the internal review justified the cost of such a study. Further, the FEU believe the study it undertook, as described in Section 2.4.3, page 4 of Appendix G in Exhibit B-1, is an appropriate study to determine the reasonableness of overhead cost allocation. If directed to do so, the FEU would have the cost allocation methodology of thermal energy activities reviewed by an independent third party. However, as noted above, as the FEU believe that the study it undertook is reasonable and appropriate, and third-party review is not needed.

79.8 When a cost allocation requires judgment and justification, such as in the case of the New Energy Solutions Video, do FEU a document an explanation for the method of cost allocation performed and is that allocation reviewed by someone whose financial compensation is not directly linked to the financial performance of FEU, such as an internal audit department?

Response:

Typically, the FEU do not prepare written documentation for a specific allocation of costs. The FEU follow a process whereby those at the FEU responsible for internal project spending approvals will allocate costs appropriately. The FEU's process for allocation of costs has been verbally communicated through the organization.

The FEU believe that its cost allocations are reasonable and appropriate. Internal Audit may review the cost allocations from time to time, for instance, as part of the process described in BCUC IR 2.79.5.

79.9 While the new Energy Solutions Video may have information pertinent to all customers, it also has information that is specific to thermal energy. Why were costs not allocated amongst the two activities?

Response:

The new energy solutions video was produced, and the costs for it incurred, in 2009, before the cost allocation mechanisms that exist today had been agreed to in the NSA for the 2010-2011 RRA. At the time the video was produced, it was identified as an important communications piece for all existing FEU customer groups. The FEU maintain that view today.

79.10 If an activity is deemed to have any benefit to general gas ratepayers, even if that impact is relatively small compared to the benefit achieved by thermal energy customers, is it FEU policy to fully allocate the cost to general gas ratepayers? If not, provide the formal policy approved and in place at FEU which is used to allocate costs.

Response:

No, the FEU do not have a policy to allocate costs fully to natural gas ratepayers even if only a small portion of the benefits accrue to natural gas ratepayers. The situation discussed in the referenced response to BCUC IR 1.158.1 was regarding the new energy solutions video which the Companies believe had and continues to have considerable benefits for natural gas customers as set out in that response. The FEU do not have a formal approved policy in place to allocate costs of this nature between the natural gas class of service and the thermal energy class of service. However, it is the FEU's practice to charge costs directly to the service that receives the benefit. The allocation of approximately $0.5 million of overhead and administrative costs from the natural gas O&M to the Thermal Energy Services Deferral Account in addition to direct costs of the thermal energy service activities provides a fair and reasonable allocation of costs to this class of service that is still in an early stage of development.

80.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.159.1

80.1 Please explain who conducted the review of the overhead allocation and concluded the $0.5M is appropriate? Do any of these individuals receive incentive compensation directly correlated to the net income of FEU, or FortisBC Inc?

Response:

The review was conducted by the Director, Financial Reporting. The review was conducted by interviewing staff in various areas across the organization for which support time was expected to be provided to thermal energy services, such as IT and finance. The review also included time of various executives who support the thermal energy services business. The FEU includes an earnings metric as part of its incentive compensation, but the FEU do not have incentive compensation policies that would cause a conflict of interest for the appropriate allocation of costs between service classes. The review and determination of the allocation was not influenced by incentive compensation.

80.2 As an example, please provide, in confidence, the allocation of the salary, expenses, and incentive/other compensation for Doug Stout for 2012 and 2013. Also provide the detailed allocation of his time between thermal and general operations of FEU for 2009, 2010 and 2011. This allocation should describe the methodology and tracking tools used to make this allocation.

Response:

For 2012 and 2013, Doug Stout has estimated that approximately 10% of his time will be allocated to thermal energy services and this has been included in the $0.5 million allocation. This allocation of time was based on a discussion with Doug Stout regarding his estimated time allocation.

The overhead charge to thermal energy services for 2010 and 2011 was agreed to as part of the NSA for those years and no specific tracking of Doug Stout's time was undertaken for 2010 and 2011, although the allocation for 2010 and 2011 would be expected to be similar to that estimated for 2012-2013. Prior to 2010, time for thermal energy services was charged to an affiliated entity using the transfer pricing methodology already in place at FEI. Please also refer to the responses to BCUC IR 1.78.1 and Corix 2.3.1

80.3 Why has an allocation of board expenses not been included in this allocation?

Response:

Please see the response to Corix IR 2.3.1 regarding corporate governance.

80.4 Why has an allocation of communications costs not been included in this allocation?

Response:

Costs for communications would be a direct charge to the deferral account via timesheets and would not be included in the allocation.

80.5 Is there any allocation for other, possibly non-anticipated costs related to thermal activities? For example, if FEU is required to undertake an activity or pay for services, is there any provision to ensure that this budget contains flexibility to absorb these costs such as a contingency provision?

Response:

Generally, the administrative services provided by the FEU to thermal energy services are routine and on-going and so non-anticipated costs would not arise. If direct non-anticipated costs do arise then they would be charged directly to the deferral account.

80.6 Please describe the tracking mechanisms in place to capture all thermal costs within each of the overhead allocated items. Provide this description by item and explain why processes exist to ensure the cost allocations are complete.

Response:

The FEU has estimated that the charge for the overhead services for 2012 and 2013 should be $0.5 million for each year. The reason for this estimation process is that the allocation of overheads takes the place of direct charging (similar to the methodology for Shared Services to FEVI and FEW), so that certain administrative functions do not need to directly charge time.

80.7 What have been actual cost allocations for each of these items in 2009, 2010 and 2011?

Response:

The charge from gas customers to thermal energy services for overhead allocation in 2010 and 2011 was $0.5 million as agreed to in the NSA. The FEU have not tracked actual overhead cost allocations for 2010 and 2011 as the allocation was already set by agreement and not subject to change, therefore, there was no need to specifically track time. In 2009, there was no thermal energy class of services within the FEU.

80.8 What happens if actual costs incurred within these overhead items exceeds this estimated cost?

Response:

The FEU does not intend to track the allocation of resources for the overhead items during the 2012 and 2013 period as it has estimated the allocation during this period. The reason for this estimation process is that the allocation of overheads takes the place of direct charging so that certain administrative functions do not need to directly charge time.

80.9 Will actual costs be tracked and compared to this estimate?

Response:

Please see the response to BCUC IR 2.80.8.

81.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.159.1

81.1 For the purposes of communication and negotiations, what policies and procedures exist to ensure that either i)a third-party contracting with FEU and ii)the general public knows the difference between the regulated and non-regulated components of FEU. Include policies that govern the use of the various FortisBC company names, email communication policies and any other formal communication policy that exists in this regard.

Response:

This response addresses both BCUC IRs 2.81.1 and 2.81.2.

There are no non-regulated components of the FortisBC Energy Utilities. There are no non-regulated activities included within the revenue requirements or cost allocation information contained in the 2012-2013 FEU RRA. Thermal energy services are a new class of service within FEI, which is a regulated public utility. Please also see the response to BCUC IR 2.79.1.

In the case where FEI resources or services are provided to a non-regulated business that is an affiliate of the regulated public utility, the FEI Code of Conduct for Provision of Utility Resources and Services, and the Transfer Pricing Policy for Provision of Utility Resources and Services are governing policies for the allocation of costs and treatment of information. Further, all employees are trained to identify appropriate from inappropriate uses of corporate technology and software for communications.

81.2 For the purposes of communication and negotiations, what policies and procedures exist to ensure that either i)a third-party contracting with any FortisBC entity and ii)the general public knows the difference between the regulated and non-regulated components of FortisBC and its affiliated entities.

Response:

Please see the response to BCUC IR 2.81.1.

81.3 Please list all of FortisBC's non-regulated entities and indicate which ones participate in Thermal activities.

Response:

The following is a list of all non-regulated entities and which ones participate in thermal activities.

Company Name	Thermal Energy activity
FortisBC Holdings Inc	No
Inland Pacific Energy Services Ltd	No
Terasen International Inc	No
Inland Energy Inc	No
FortisBC Alternative Energy Services Inc	Yes *

* This company has a number of operating thermal energy assets which were developed prior to 2010.

81.4 Is the regulated utility business of FBU being used to build brand awareness of non-regulated entities?

Response:

No, the regulated utility business of the FEU is not being used to build brand awareness of non-regulated entities. As indicated in the response to BCUC IR 2.79.1 the thermal energy services being engaged in by the FEU are regulated public utility activities and are being provided as a separate class of regulated service within FEI. The thermal energy services are being offered to meet the demand for these energy services from the FEU's customers and to contribute to meeting the province's energy objectives, while keeping natural gas as part of the energy solutions within these projects.

81.5 Is the regulated utility business of FBU being used to support non-regulated entities such as by providing security or credibility to negotiations outside of FEU?

Response:

No the FEU's regulated utility business is not being used to support non-regulated entities in the manner suggested in the question. The thermal energy activities being engaged in by the FEU are all regulated public utility activities under the UCA. The FEU's business is all regulated and separate from any non-regulated business activity. The NRB Code of Conduct and Transfer Pricing Policies are in place to govern business practices and track costs for any services provided to a non-regulated business if and when that occurs.

81.6 By keeping non-regulated thermal energy items within FEU, is FEU able to use regulated assets or operations to benefit negotiations with third parties regarding non-regulated thermal activities?

Response:

There are no non-regulated thermal energy items within FEU. Please see the responses to BCUC IRs 2.81.1 and 2.79.1.

82.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.160.1

Thermal Energy – Sales and Marketing O&M and Business Development

"The overhead allocation of $0.5 million from the FEU to the Thermal Energy deferral account includes the allocation of time for the VP of Energy Solutions and External Relations ("ES&ER").

…These allocations are expected to remain similar through 2011, 2012 and 2013. There were no expenses such as meals, travel accommodations or promotion associated with the VP of ES&ER's time captured in the deferral account in 2010."

82.1 Given the increase in thermal energy activity from 2011-2013 please explain why the allocation of the V.P. of ES & ER remains the same.

Response:

The increase in thermal energy services activity in 2011 through 2013 is due to growth in project development work and capital spending within specific projects. These tasks are conducted by staff who charge their time directly into the Thermal Energy Services Deferral Account. These are not tasks undertaken by the VP of ES&ER.

As explained in Section 2.4.3 of Appendix G in Exhibit B-1, the allocation of time by FortisBC executives such as the VP of ES&ER to thermal energy services activities is for the review and monitoring of project status and any project approvals that are required. While the development of several thermal energy services projects are advancing, the amount of time that the VP of ES&ER and other executives need to spend on such status updates, review and approvals remains small in comparison to their other activities and responsibilities. This level of activity is expected to remain consistent through the RRA period and therefore no change in the allocation of time for FortisBC executives has been made.

By offering these two classes of service within FEI, FEI is able to have a positive impact on rates for both gas and thermal energy customers, over time, the mechanism to calculate the common services amounts and how to allocate these costs across two classes of service within FEI will need to mature as the thermal energy services business develops. As an example, FEI, FEVI, and FEW have developed the Shared Services Agreements that have been in place and accepted by the Commission since 2003. The approach used to determine the overhead for 2012 and 2013 is reasonable given that there are no relevant allocators within the thermal energy services class of service at this time, which is a direct reflection of the early stage of development of this class of service. To provide some context, the $500,000 of shared services that has been proposed for 2012 and 2013 is approximately double the shared service amount being allocated to FEW ($264,000 in 2011) on about $40 million of rate base, having 2,610 customers, and consuming about 731,000 GJ of natural gas per year.

> *"As such, each of the listed activities was conducted for the benefit of the FEU's natural gas customers, as well as potential future thermal energy solutions customers, as evidenced by the following observations:*
>
> *…FEU's participation will ensure that natural gas continues to be a part of the energy mix as a back-up or supplementary fuel."*

82.2 Central Okanagan School District and the two Clean Energy Biomass-Fuelled Projects will use natural gas as a back-up or supplementary fuel. Do customers that use natural gas as a back-up or supplementary fuel generally have low load factors which reduced system utilization, increase peak day load, increased system improvement costs; thereby increasing rates for all customers? Please explain.

Response:

While it is true that customers who opt to use alternative energy systems reduce gas system utilization from what they otherwise would have, had they adopted conventional gas systems, it is not necessarily true that they therefore increase peak day load, system improvement costs and rates as suggested in the question. Each instance is unique. In many thermal energy cases the customers are retrofitting their premises, therefore the gas infrastructure is already in place and serving them does not require additional facilities. In fact, moving to thermal energy and using natural gas as a back-up fuel source may free up capacity on the FEU's system to serve other customers, reducing system costs.

Customers using natural gas as a back-up system can be viewed in a similar light to other types of customers such as those undertaking energy efficiency improvements - by using less energy they reduce their contribution to the system relative to what they would have under a status quo case. However all customers contribute to the cost of service of the system so continuing to have these customers actually reduces the costs for gas customers from what they would have been had they opted not to use the system any longer.

If a class of customers such as thermal energy customers is not contributing enough to cover the cost of serving them or, put another way, raising costs for other customers as the question suggests, this becomes a cost allocation and rate design issue and rates can be changed to ensure that they contribute adequately to the system. As discussed in the response to BCUC IR 2.82.3, it is the FEU's intention to review its rate schedules, one of which will be a peak load rate for thermal energy as part of its Rate Design Phase 'B' Application to be filed in 2012.

It is the FEU's opinion that at this early stage there is not enough impact to warrant separate treatment of these customers. It is also FEU's opinion that given government policy and customer preference for these types of solutions that these customers should be accommodated and that retaining them as customers will ultimately benefit all gas customers.

82.3 Does the proposed rate design application deal with Thermal Energy and other low use and low load factor customers that on average incur a higher cost of service than other customers in a similar rate class?

Response:

The FEU has planned a two-step process for its upcoming rate design applications that it believes will provide a full and appropriate review of cost allocation, rates and rate structures. In the Amalgamation and Rate Design Phase 'A' Application for 2013 rates (to be filed later in 2011) the Companies will apply to the Commission for approval to amalgamate and postage stamp the rates and rate structures. In its Rate Design Phase 'B' Application for 2014 rates (to be filed in the second half of 2012, subject to approval of the Amalgamation and Rate Design Phase 'A' Application) the amalgamated FEU will examine customer segmentation and rate structures - including thermal energy, low use and low load factor customers - that are designed to meet the needs of customers and stakeholders of the Amalgamated entity. The FEU believe this is an appropriate rate design process for a transition to the amalgamated entity, postage stamping and a full review of the cost allocation, customer segmentation and rate structures.

83.0 Reference: Thermal Energy

Exhibit B-9, BCUC IR 1.160.1

2010 Canadian District Energy Association conference and exhibition (2010 CDEA) Program, pp. 7, 10 and Floor Plan

Terasen participated in and sponsored the 2010 Canadian District Energy Association Conference and Exhibition.

(2010 CDEA Program, p.7)

Platinum Sponsors:

BC hydro powersmart | BORDEN LADNER GERVAIS | Terasen

(2010 CDEA, p.10 and Floor Plan)

Exhibitor Floor Plan

1 FVB Energy Inc.
2 Dalkia
3 BC Hydro
4 Corix Utilities
5 Federation of Canadian Municipalities
6 Borden Ladner Gervais LLP
7 Terasen Energy Services
8 Terasen Energy Services
9 Wellons Canada
10 Stantec Consulting Ltd.
11 Urecon Ltd.
12 Itron Canada Inc.
13 Trane Northwest
14 Canada Mortgage & Housing Corporation
15 Fink Machine Inc.
16 Enmax
18 Glasscell Isofab
19 CEM Engineering
20 Advance Industrial Components
21 Aalto Inc.
22 Le Groupe Simoneau Inc.
23 Nexterra Energy
24 Victaulic
25 European Power Systems Ltd.

(2010 CDEA Program, p. Floor Plan)

2010 Conference Planning Committee:

The CDEA wishes to recognize the commitment and contribution of its 2010 conference planning committee:

- Stacey Bernier, Technical Director, Sustainable Energy, Corix Utilities *(Conference Committee Chair)*
- Bruce Ander, President and CEO, Markham District Energy and CDEA Chair *(ex officio)*
- Richard Damecour, President and CEO, FVB Energy Inc. and CDEA Vice Chair
- Dave Falcon, Operations Superintendent, Central Heat Distribution Limited
- Bob Fearnley, Councillor, City of North Vancouver
- Veronica Friesen, Director, District Energy Windsor, Windsor Utilities Commission
- Gareth Jones, Director, Business Development, Terasen
- Glenn Miller, Vice President, Education and Research, Canadian Urban Institute
- Marlena Rogowska, Partnership Officer, Education and Research, Canadian Urban Institute and CDEA Secretariat
- Richard White, Director, Community Development, City of North Vancouver

(2010 CDEA Program, p.13)

83.1 Using the table below please provide the cost and cost allocation of Terasen's participation and sponsorship of the 2010 CDEA Conference and Exhibition. Also provide the number of Terasen employees supporting Booths 7 & 8 and the number of Terasen employees attending the 2010 CDEA Conference. Also provide the table in fully functional electronic format.

Activity	Reference	Cost	Cost Allocation
Advertisement	CDEA, p.7	$500	100% Terasen Energy Services
Platinum Sponsorship	CDEA, p. 10		
Booths 7 & 8	2010 CDEA, p. Floor Plan		
Employee labour supporting Booths 7 & 8			
Promotional Material for Booths 7 & 8			
G. Jones Conference Planning Committee	CDEA, p. 10		
Fees for Employees attending the 2010 CDEA Conference			
Travel, meals and accommodation expenses			

Response:

This response addresses both BCUC IRs 2.83.1 and 2.84.1.

The requested information is provided in Tables 1 and 2 below. While FEU's attendance at the 2010 conference, which was held in North Vancouver, BC, was important for the benefit of both natural gas and thermal energy service customers, the majority of costs were allocated to the Thermal Energy Services Deferral Account. The FEU's presence at the 2011 conference held in Toronto, Ontario was significantly reduced from that of the 2010 conference due to its location and integration with the International District Energy Association. This conference provided an important educational opportunity for three staff, two of whom shared booth duties. All of the costs for the 2011 conference were allocated to the Thermal Energy Services Deferral Account.

The FEU have not confirmed the reference information inserted into these tables by the Commission, but rather has transposed it verbatim into the response. Please note that since the 2011 conference occurred at the very end of June, some amounts in Table 2 are estimates.

Table 1: Cost and labour allocation for the 2010 Canadian District Energy Association Annual Conference in North Vancouver, BC

2010 CDEA			
Activity	**Reference**	**Cost**	**Cost Allocation**
Advertisement	CDEA, p7	$500	See Note 1 below
Platinum Sponsorship	CDEA, p10	$15,000	100% Thermal energy deferral account
Booths 7 & 8	2010 CDEA, p floor plan	$1,295	100% Thermal energy deferral account
Employee labour supporting Booth 7&8	6 employees approx 19 hours	19.0 hours	see Note 2 below
Promotional materials for Booth 7&8	advertising - misc	$4,924	100% Thermal energy deferral account
Director, Business Development, Thermal Energy Services - Conference Planning Committee	expenses	$587	100% Thermal energy deferral account
Fees for employees attending the 2010 CDEA Conference	emp course fees+membership dues	$3,672	100% Thermal energy deferral account
Travel, meals & Accomodation Expenses	travel, meals & allow-mileage	$1,489	100% Thermal energy deferral account

Note 1: FEU is unable to confirm this amount.

Note 2: FEU has provided the total number of hours of staff supporting the FEU booth at this conference, but did not access each employees personal salary information to provide a cost for these hours. Some of the staff attending this conference work primarily on thermal energy projects and attended in support of thermal energy customers, while others attended on behalf of natural gas customers. Timesheets of each staff member would have been coded accordingly such that some labour costs were allocated to the thermal energy deferral account and some were allocated to FEU O&M for natural gas service classes. This row does not include the time for Director of Business Development for Thermal Energy Services, whose attendance at the conference was allocated to the thermal energy deferral account.

Table 2: Cost and Labour Allocation for the 2011 Joint Canadian and International District Energy Association Conference in Toronto, Ontario

2011 CDEA			
Activity	**Reference**	**Cost**	**Cost Allocation**
Booth 57	2011 IDEA Conference p26	$5,000	100% Thermal energy deferral account
Employee labour supporting Booth 57	2 employees approx 10.0hours	10.0 hours	100% Thermal energy deferral account
Promotional Material for Booth 57			100% Thermal energy deferral account
Director, Business Development, Thermal Energy Services - CDEA Board Member	expenses	$91	100% Thermal energy deferral account
Fees for employees attending the 2011 CDEA Conference	membership dues	$900	100% Thermal energy deferral account
Travel, meals & Accomodation Expenses	travel, meals & Allow-mileage -	$1,625	100% Thermal energy deferral account

General: Booth fees included conference registration for 1 staff member. Conference fees included annual CDEA membership.

84.0 Reference: Thermal Energy

2011 International District Energy Association (IDEA)/CDEA Conference & Trade Show Program (2011 IDEA Conference), pp. 19, 26, 36 and 52

2011 IDEA Conference

FortisBC was a participant at the 2011 IDEA Conference.

SESSION C1
Sustainable Infrastructure Options
Pier 4 & 5

Moderator: *Michael Burns, District Energy St. Paul*

Powering Up Cities Through Energy Density Mapping – *Brent Gilmour, Urban Solutions*

Fortis BC Integrated Energy Model for Low Carbon British Columbia – *Gareth Jones, Fortis BC*

(2011 IDEA Conference, p. 19)

Company	Booth
Fibrelite Composites Ltd	23
Flexim Americas Corporation	42
Flow Control Industries, Inc.	45
Flow Safe Inc.	125
Fortis BC	57

(2011 IDEA Conference, p. 26)

FortisBC .... Booth 57
Fraser Highway
Surrey, BC, V4N 0E8 Canada
(604) 592-7969 (866) 792-7969
tes@fortisbc.com; fortisbc.com

Gareth Jones; Director, Business Development

FortisBC is committed to delivering alternative energy sources that address the energy needs of British Columbians, while also reducing the impact these sources have on our environment. Whether it's a new development or an existing community, FortisBC has the experience and resources needed to execute all phases of your district energy system project.

(2011 IDEA Conference, p. 36)

<u>CDEA Board Members</u>

GARETH JONES
Director, Business Development
FortisBC Energy Inc.
(250) 380-5792
gareth.jones@fortisbc.com

(2011 IDEA Conference, p. 52)

84.1 Using the table below please provide the cost and cost allocation of FortisBC's participation at the 2011 CDEA Conference & Trade Show at the Westin Harbour Castle Hotel, Toronto, Ontario. Also provide the number of FortisBC employees supporting Booths 57 and the number of FortisBC employees attending the 2010 CDEA Conference. Also provide the table in fully functional electronic format.

Activity	Reference	Cost	Cost Allocation
Booth 57	2011 IDEA Conference, p. 26	$5,000	100% FEI Alternative Energy Deferral Account
Employee labour supporting Booths 57	2011 IDEA Conference, p. 26		
Promotional Material for Booth 57	2011 IDEA Conference, p. 26		
G. Jones CDEA Board Member			
Fees for Employees attending the 2011 CDEA Conference			
Travel, meals and accommodation expenses			

Response:

Please see the response to BCUC IR 2.83.1.

85.0 Reference: Revenue Requirements and Rates

Exhibit B-8, CEC IR 1.4.1, pp. 23-24; Exhibit B-9, BCUC IR 1.165.2 and 1.165.3,

pp. 582-584

Impact of Expanded Service Offerings on Revenue Requirements

"Overall, the net impact of the Biomethane and CNG and LNG service offerings is a net decrease to the revenue requirement of approximately $1.2 million in 2012 and approximately $1.8 million in 2013."

85.1 Please quantify the net impact of the Biomethane and CNG and LNG Service offerings on revenue requirements for 2012 and 2013 if no further EEC incentives for NGVs are provided taking into account the responses to BCUC IR 1.165.2 and BCUC IR 1.165.3.

Response:

If no further EEC incentives for NGVs are provided, the net impact is a revenue deficiency of approximately $2.1 million in 2012 and $3.2 million in 2013. As a result, the delivery rates for non-bypass customers will increase by approximately 0.4% in 2012, and approximately 0.6% in 2013, as compared to the rates proposed in the Application. This impact is comprised of two components – a reduction in revenue and a reduction in the cost of service associated with the CNG and LNG Service offering.

- Revenue: The greatest impact on the revenue requirements would be the reduced CNG and LNG Service load and its impact on reduced forecast delivery margin and fueling service revenue. The volume loss from forecast would be approximately 347,500 GJ in 2012 and 572,800 GJ in 2013 resulting in reduced revenues of $2.4 million in 2012 and $4.1 million in 2013.
- Cost of Service: Partially offsetting the impact of the reduced revenues, would be a decrease in the cost of service associated with no further investment in CNG / LNG fueling stations in 2012 and 2013 ($4.0 million and $3.8 million respectively) and corresponding reductions in the associated operating and maintenance expense of those forecast fueling stations. The total decrease in the cost of service is approximately $306 thousand in 2012 and $922 thousand in 2013.

If no further EEC incentives for NGVs are provided, the overall funding envelope of $74.5 million for EEC will reduce to $64.5 million. The $20 million rate base addition to the EEC deferral account as currently forecast in 2012 and 2013 would remain the same and the maximum addition to the non-rate base deferral account for 2012 and 2013 would decrease to $44.5 million from $54.5 million. Therefore, because the addition to the rate base account remains the same, there is no impact on the revenue deficiency in 2012 and 2013 associated with eliminating any future EEC incentives for NGVs.

The FEU continue to believe that providing incentives to NGV customers is an important step in the transformation of the NGV market and that overall existing natural gas customers benefit both qualitatively and quantitatively from CNG and LNG Service. Given the fact that the fuelling stations which support these NGV vehicles, to which the incentives are made, have a useful life of 20 years and will have underlying take or pay contracts (~10 years), it is expected that benefits for years to come will materialize for existing customers.

There is no impact on the Biomethane Service offering if EEC incentives for NGV are no longer provided.

85.1.1 Please update the data in the CNG and LNG Service Offerings table in section II of the response to CEC IR 1.4.1 (page 24) in the case where no EEC incentives for NGVs are provided.

Response:

The following table updates the revenue requirements impact for 2012 and 2013 as provided in the response to CEC IR 1.4.1, assuming no further NGV incentive funding and its impact on Rate Base, the Cost of Service and CNG / LNG Recoveries. The Return on Rate Base for the Incentives Excluded scenario has been updated to reflect the July 19th Evidentiary Update for FEI, Tab 7.1, Schedules 80/81. The consequence of no further incentive funding is to decrease the surplus, in the response to CEC IR 1.4.1, from $2.5 million to $0.3 million in 2012 and to decrease the surplus from $3.3 million to $0.1 million in 2013.

		$ Thousands				
		EEC Incentives Included			2012/13 EEC Incentives Excluded	
		CEC IR 1.4.1			BCUC IR 2.85.1.1	
Particulars		2012	2013		2012	2013
Rate Base		$ 7,868	$ 12,520		$ 5,925	$ 6,903
Return on Rate Base		7.75%	7.75%		7.80%	7.79%
Station & Transmission O&M Expense		384	605		274	274
Less: Overheads Capitalized	14%	(54)	(85)	14%	(38)	(38)
Net O&M Expense		330	520		236	236
Depreciation Expense		475	778		361	441
Amortization Expense		(24)	(24)		(24)	(24)
CNG / LNG Service Revenue		(3,744)	(5,398)		(1,304)	(1,304)
Income Tax Expense		(119)	(152)		(60)	0
Earned Return		610	970		462	538
Total Incremental Revenue Requirement		$ (2,472)	$ (3,305)		$ (329)	$ (112)

85.2 What is the impact on the revenue requirement if the recovery of EEC incentives for NGVs paid to date is disallowed?

Response:

If the recovery of incentives for NGVs paid to date is disallowed, it will result in a reduction to the cost of service and revenue requirements of approximately $870 thousand in 2012 and $840 thousand in 2013, and decreasing each year thereafter.

FEI believes that the incentives for NGVs were prudently incurred and thus recoverable through rates; NGV incentives paid to date are cost-effective and among the strongest programs when assessed through the Total Resource Cost ("TRC") test.

The addition of CNG and LNG Service customers in 2011 is a direct result of incentives of approximately $5.6 million. The addition of approximately 169 TJs[10] to the throughput on the delivery system from these CNG and LNG Service customers contributes long term incremental

[10] Based on minimum contract demand

delivery margin recoveries, including under Rate Schedule 16, of approximately $320 thousand per year.[11] Given the fact that the fuelling stations that support these NGV vehicles, to which the incentives were made, have a useful life of 20 years and an underlying take or pay contracts (~10 years), it is expected that benefits for years to come will materialize for existing customers. Over the 10 year term of the fuelling contracts it is reasonable to assume a $3 million incremental delivery margin, with future upside related to the fuelling asset that will still have 10 years of service life remaining after the initial term of the contract.

As discussed in the response to BCUC IR 1.199.2, the NGV incentive program has been designed to kick-start a market transformation from diesel fuel to natural gas for fleets of heavy duty vehicles. Adding NGV load is one of a few means available to FEI to combat declining throughput that, left unchecked, will continue to contribute to higher rates over time. Further, NGV initiatives produce environmental benefits for all customers, help meet Provincial GHG emission reduction targets, and support BC's energy objectives.

The FEU will provide further information in support of the prudence of the incurred expenditures as part of the process the Commission is establishing for that purpose.

11 This excludes the O&M component of the Rate Schedule 16 variable charge. Total delivery margin recoveries associated with CNG and LNG Service are forecast at approximately $600 thousand per year.

86.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-9, BCUC IR 1.167.5, p. 589

Revenues from NGV Initiatives

"The revenues associated with the transportation of LNG from Tilbury to the LNG fueling station are not included in this Application."

"The costs of the LNG tankers owned by FEI are already embedded in existing rates. Thus these costs exist with or without the development of LNG customers. Any additional costs (i.e. fuel surcharge) will be recovered through the LNG tanker service charge. Revenues for this service will be captured and included in the proposed CNG and LNG Costs and Recoveries deferral account."

86.1 Is the CNG and LNG Costs and Recoveries deferral account the same deferral account requested in the CNG and LNG Service Application dated December 1, 2010?

Response:

Yes, it is the same deferral account.

Please refer to the responses to the BCUC IR 1.112 series of questions. In the RRA, FEI has proposed that this account be expanded to capture the variance in total Rate Schedule 16 revenues collected from the forecast of $2.9 million in 2012 and $4.1 million in 2013 included in this Application. Although expanded, the general intent of the deferral account remains consistent with the account as requested in the CNG and LNG Services Application - to collect the un-forecast incremental fueling station revenue and pass it on to all non-bypass customers.

86.2 If this is the same deferral account as requested in the CNG and LNG Service Application, was it explored or discussed in the CNG and LNG Service Application that the revenues for the transportation of LNG from Tilbury to the LNG fueling station would be captured in the requested deferral account? If so, please provide the appropriate reference.

Response:

No, including revenue variances due to the tanker service charge in the deferral account was neither explored nor discussed in the referenced December 1, 2010 Application.

Revenues for transport of LNG from the supply source to the customer site were not discussed in the CNG and LNG Service Application in any depth, largely because the dollars associated with this service are not material and the proposed business model is designed to be revenue neutral with no material impact on existing customers.

There are two elements to the transportation charge for the tanker. The first is a cost recovery charge that ensures that FEI's actual costs, including administration and overhead, incurred in arranging transport through a third party carrier are recovered. The second is a charge for use of FEI's existing LNG tankers. This second charge provides a revenue contribution that will partially offset costs to existing customers. On July 12, 2011 FEI submitted an Application to the Commission for approval of a daily charge for use of its LNG tankers, along with other approvals sought.

86.3 If a non-NGV customer requested LNG tanker service, would the service be available to such customer? If so, would the same LNG tanker service charge apply as would apply if the customer was an NGV customer?

Response:

Yes, FEI proposes to use the same LNG tanker service charge for all LNG customers that wish to utilize FEI tankers for delivery of LNG. FEI submitted an Application to the Commission on July 12, 2011 seeking approval of a daily charge for the use of its LNG tankers. In this Application, FEI proposed that the daily charge (capital component) remain the same for all LNG customers, and that the third party charge (variable O&M component) will be updated to reflect the expected number of trips, duration of trip, labour rate, and fuel surcharge items.

86.4 To the extent the LNG tanker service charge was recovered from a non-NGV customer, is FEI proposing that these revenues be captured in the proposed CNG and LNG Costs and Recoveries deferral account?

Response:

FEI expects that any revenues to be recovered from non-NGV customers will be minor over the 2012 and 2013 period. As a result, FEI has not proposed to capture these revenues in the CNG and LNG Costs and Recoveries deferral account; however, FEI would be willing to expand the account to include non-NGV customer recoveries pertaining to LNG tanker transportation.

86.5 For the LNG tankers owned by FEI that are already embedded in existing rates, what is the depreciation rate that applies and how was it determined?

Response:

FEI's accounting records currently show one LNG tanker in asset class 485-20 Heavy Mobile Equipment purchased in December 2010. A second LNG tanker currently being used is fully depreciated, having been built in 1971 and purchased in 1996.

Previous to 2012, assets in asset class 485-20 were depreciating at 8.48%. The current recommended depreciation rate for this asset class is 18.06% and reflects a useful life of only approximately 6 years. The revised rate for the asset class was established using the recommendations from Gannett Fleming in the latest depreciation study and is applicable to the wide variety of assets included in this asset class.

The tanker purchased in 2010 is anticipated to have a useful life of approximately 20-30 years depending on the frequency of use. This 2010 tanker was not included in the depreciation study, as it only included assets existing at December 31, 2009.

87.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-9, BCUC IR 1.169.4, pp. 593-594

Revenues from Rate Schedule 16

"FEI has had high-level and confidential discussions with a small number of potential LNG customers who might be interested in using LNG for remote generation of electricity and also under high-level consideration is the concept of using vapourized LNG to displace propane in existing distribution grids."

87.1 Is FEI proposing to include Rate Schedule 16 revenues from non-NGV customers in the proposed CNG and LNG Costs and Recoveries deferral account?

<u>Response:</u>

Yes, if a non-NGV customer takes service under Rate Schedule 16. As discussed in the response to BCUC IR 1.112.1, the deferral account will capture the variance in total Rate Schedule 16 revenues collected from the forecast of $2.9 million in 2012 and $4.1 million in 2013 included in this Application.

FEI does not have any non-NGV customers under Rate Schedule 16 at this time. Please see our response to BCUC IR 2.87.2 for additional discussion on this topic.

87.2 What is the likelihood, expressed in percentage terms, of a non-NGV customer taking service under Rate Schedule 16 in each of the years 2011, 2012 and 2013?

<u>Response:</u>

FEI believes that the economic and environmental drivers that are stimulating interest in LNG for transportation applications also apply to the use of LNG in off-grid power generation markets. In both cases the incumbent fuel is diesel, which has high GHG emissions and high costs relative to LNG. FEI has had market development discussions with several interested customers at the feasibility study stage. While there is no way to accurately estimate the probabilities as requested in the question, FEI believes there is a 50% likelihood that a demonstration project or projects can be established within the 2011 to 2013 time frame. Given project development and execution lead time it is unlikely this would lead to revenue under Rate

Schedule 16 until 2013. Therefore the probability of Rate Schedule 16 revenue for each of the three years is estimated in the table below.

Year	Probability of Rate Schedule 16 service for non-NGV
2011	0%
2012	10%
2013	50%

The Rate Schedule 16 revenue and volume forecasts presented in Appendix I of this RRA do not include non-NGV LNG customers. FEI has requested approval of a deferral account to capture variances in LNG costs and recoveries and as such, recoveries from non-NGV LNG customers would be captured in this deferral account.

88.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-9, BCUC IR 1.165.2 and IR 1.165.3, pp. 582-584

Revenues from NGV Initiatives

If EEC incentives are not available for NGVs, FEU quantified the impact on the forecast revenue from transportation revenue as follows:

"The forecast revenues in 2011 are expected to remain the same because the 2010/11 EEC incentives are embedded in the existing rate base. In the absence of EEC incentives for NGVs for 2012 and 2013, revenues would decrease by approximately $1.0 million ($1.6 million with EEC - $0.6 million without EEC) in 2012 and $1.7 million ($2.3 million with EEC - $0.6 million without EEC) in 2013."

88.1 Are the revenues that remain in the forecast of transportation revenue entirely attributed to only those NGV customers that have received EEC funding for NGVs that FEU has committed to date?

Response:

Yes, with the exception of revenues from existing Rate Schedule 6 customers. In the absence of incentive funding, the market for NGVs in BC has stagnated. FEI has stimulated the market through the use of incentives for four customers to date, indicating that it is possible to kick-start the market. FEI's strategy calls for the gradual reduction and elimination of incentive funding over time as the market grows. If, however, incentives are eliminated after only four projects have been completed FEI believes it is unrealistic to assume that the market would have been sufficiently stimulated to continue to grow on its own.

88.2 Please confirm the amount of EEC funding for NGVs that FEU has committed to date is $5.587 million.

Response:

Confirmed, in 2010 and 2011 FEU has committed a total of $5.587 million in EEC funding for NGVs.

89.0 Reference: Biomethane

Exhibit B-9, BCUC IR 1.177.1-9

89.1 Please confirm that Order G-194-10 approval a budget for customer education and did not approve a budget recoverable from all gas customers, for advertizing the biomethane product.

<u>Response:</u>

Order G-194-10 approved proposed costs associated with making the biomethane service offering available to all customers, which included customer education with some marketing, to be recoverable from all non-bypass customers. FEI discussed at length on page 56 (section 6.6) of the Biomethane Application and in response to BCUC IRs 1.18.2, 1.18.4, 1.60.3, 1.60.5 and 1.60.6 in the Biomethane Application (excerpts included in Attachment 89.1), the need for educational, promotional, awareness and retention components in the customer education plan. The Commission Determination in response to the proposed cost methodology allocation on page 51 of the Biomethane Decision indicates

> *"… the Commission Panel agrees with FEI (Terasen) and the CEC that it is in the long term interest of all FEU (Terasen utility) customers that new initiatives contribute to the retention and the addition of throughput in the system, which will result in system costs being spread over a larger base…**<u>It is in this context that the Commission Panel approves the cost allocation methodology proposed by Terasen Gas for the test period as just and reasonable".</u>*** [emphasis added]

There was no specific direction to segregate any elements of its customer education plan to biomethane customers.

89.2 Please provide commonly accepted definitions from a reputable dictionary for both i)education and i)advertising and explain the difference between the two.

Response:

In the Canadian Oxford Dictionary,[12] "education" is defined as the act or process of educating or being educated. Four definitions are provided for "educate", as follows:

1. "give intellectual, moral, and social instruction to a (pupil, a child), esp. as a formal and prolonged process";
2. "provide education for";
3. "train or instruct for a particular purpose";
4. "instruct, advise or give information to."

The same Canadian Oxford Dictionary provides four definitions of advertise:

1. "draw attention to or describe favorably (goods or services) in a public medium to promote sales";
2. "make generally or publicly known";
3. "seek by public notice, esp. in a newspaper";
4. "notify".

It can be seen that advertising and education are similar in the sense that both involve the conveying of information. They are also not exclusive concepts. Advertising, for instance, can be a way of educating in the sense that by "making something generally or publically known" one is "giving information". Advertising can, however, have the sense of promoting a good or service which is not found in the definition of education.

For the Renewable Natural Gas product offering, education and advertising are both necessary to create awareness, stimulate interest, encourage and maintain participation.

As biomethane has not previously been available as an energy source in B.C., customers must first be made aware of its introduction to the marketplace and its environmental benefits. As people are less likely to buy products or services that they do not understand, educational communication (in the sense of "advise or give information to") is necessary. Customers will be informed about biogas and biomethane as a real, practical and safe energy source that is available today, and the benefits of its use in B.C.

The FEU use advertising as one of many tools available to generate awareness, convey information and educate customers on a number of items related to the utilities business.

[12] 2nd Edition, 2004.

Examples include alerting customers to safety issues, the availability of or changes to products and services including quarterly gas commodity changes, stable rate program, and opportunities to participate in regulatory proceedings and job opportunities.

As the supply of the biomethane/natural gas blend warrants, and within the approved customer education budget, communications for the Biomethane Program will continue to require educational and promotional elements to maintain successful participation and encourage additional supply to realize the environmental benefits of the product offering.

89.3 What assumptions has FEU made in determining that the biomethane communications meets the definition of education?

Response:

The FEU have not "made assumptions in determining that the biomethane communications meet the definition of education." Please see the response to BCUC IR 2.89.1 for a discussion regarding the nature of the Commission's Biomethane Order.

FEU has used its current established communication channels, such as the corporate website and bill inserts, to make its target audience aware of biomethane as source of energy and the environmental benefits associated by participating in this program.

For example the video, "What is Renewable Natural Gas?"[13], incorporates a learning component of "how bacteria makes yuck useful and creates renewable natural gas". Other communications such as the bill inserts, newsletters and other channels include elements of education, such as by providing information on how biomethane is created from waste.

89.4 Typically, education includes informing others of the benefits as well as the shortcomings or alternatives to the subject matter. For example, education will typically communicate both the pros and cons and alternatives of any particular subject. What are the shortcomings or alternatives that FEU intends to communicate regarding Biomethane? Will these items be given equal prominence or value in communications made by FEU?

[13] http://www.fortisbc.com/NaturalGas/Homes/Offers/RenewableNaturalGas/Pages/default.aspx)

Response:

The purpose of the biomethane customer education is to make customers aware of the existence and benefits of the Biomethane Program and to encourage their adoption of it. The FEU are not aware of any relevant negative aspects of the Biomethane Program, other than higher cost, which customers are made aware of. The FEU do not intend to use these limited funds to market other technologies.

89.5 Is it expected that the proposed education plan for biomethane will create a preference towards biomethane over other energy sources?

Response:

The FEU do not intend to contrast biomethane with any energy source other than traditional natural gas. The purpose of the education plan is to create an awareness of the offering and educate customers regarding its attributes that come with the premium price. As a result of that awareness, some customers may develop a preference for it as an informed energy source.

In 177.5, FEU makes the following statement: *"but a certain level of customer education will be required indefinitely in all areas to maintain a reasonable level of awareness of biomethane and* <u>*participation and support for the program*</u>*."* In 177.7, FEU states*" communication will be a key component for education consumers about the biomethane program and* <u>*encouraging participation in the product offering*</u>*."*

89.6 Please explain why i) awareness, ii) participation and iii) support for biomethane constitute education and not advertising.

Response:

The implicit assumption in the question is that the Commission approved only "education" and not "advertising"; however, as described in BCUC IR 2.89.1, the FEU understand that the Commission approved the customer education plan, which the FEU had explained in a number of instances included both elements. Advertising is a tactic than can be employed to reach any number of goals. Frequently, the FEU employ advertising to notify the public of job openings, regulatory proceedings and gas safety education. Advertising is also being employed as a tool to further the goals of the biomethane customer education program. Advertising is one of many methods of promoting awareness of, participation in, and support of the Biomethane Program. As such, there is a complementary relationship between education and the advertising being used to further it. Please also see the responses to BCUC IRs 2.89.1, 2.89.2 and 2.89.3.

89.7 For the purpose of education, isn't the goal of such a program to inform customers of more environmentally sound usage of energy, such as biomethane or other forms of greener energy.

Response:

No, the purpose of the Biomethane Program customer education plan is specifically to inform customers of, and encourage their adoption of, the Biomethane Program. In the Biomethane Decision, the Commission Panel stated

> *" …. the Commission Panel agrees with FEI and the CEC that it is in the long term interest of all FEI utility customers that new initiatives contribute to retention and the additional of throughput in the system, which will result in system costs being spread over a larger base"* (reference: page 51, Biomethane Decision Order G 194-10).

Please see the response to BCUC IR 2.89.1.

89.8 Does the customer education provide any alternatives to gas customers to become more environmentally sensitive? For example, promoting the reduction of gas use, the consideration of the use of solar energy for individual purposes or any other alternative energy offering not made by FEU? Or does the education promote one single product, which is only offered by FEU, to becoming more environmentally sensitive?

Response:

As discussed in detail in the Biomethane Application, approved by Commission Order G-194-10, the customer education program for the Biomethane Program is intended to educate customers about, and promote the adoption of, the Biomethane Program only. As such, the

Biomethane Program customer education program does not address consideration of other environmentally sensitive energy such as solar energy or other such technologies.

Promotion of solar technologies and reduction of gas use is achieved through EEC programs. There are separate EEC budgets that cover energy efficiency and conservation related education and outreach. It is the Company’s practice to seek opportunities wherever possible to consolidate multiple key messages in one communications vehicle, where costs are allocated on a proportional basis for each individual initiative that is being promoted. For example: FEU may have a booth at a tradeshow funded from the biomethane education budget, but within the booth there may also be a brochure promoting EEC programs and those particular pieces would be paid for from the EEC program budget.

Please also refer to BCUC IR 2.89.7.

89.9 Will FEU’s customer education plans make it difficult for other, non-FEU energy sectors to fairly compete with Biomethane if these education plans include elements of advertising?

Response:

FEU cannot see any reason why our customer education program would make it difficult for other sectors to compete with the FEU. The FEU will develop communications which are specific and focused on biomethane as a renewable source and the details of the program itself. In the event that other providers develop biomethane projects or offer other “green” gas products, those companies will have to incur costs to advertise their products, which is consistent with competitive businesses which have to undertake costs to promote and sell their product. Given that the utility has started the education and awareness of the energy form, these companies will benefit from a greater level of public understanding of the product than there is today. As an example, Bullfrog Power is already offering “green” electricity and natural gas in BC as a way for consumers to reduce their carbon foot print associated with their energy use.

As described in BCUC IR 2.89.1, the FEU believe that the customer education plan is being executed in the manner in which it was described in the Biomethane Application. Please also refer to Biomethane Application BCUC IR’s 1.14.1, 1.14.1.4, 1.18.1 and 1.18.4, excerpts provided in response to BCUC IR 89.1, Attachment 89.1.

89.10 Does FEU intend to measure the success of the customer education of Biomethane by the total value of biomethane sold to customers?

Response:

The total value or the volume of Biomethane sold could be one of the measures of success as participation is directly proportional to volume. However during phase 1, the FEU would measure success on the level of awareness, participation and retention in the program for eligible residential customers.

Please see the response to BCUC IR 2.89.11.

89.11 If existing gas customers decide to reduce gas consumption as a result of the customer education, rather than switching to biomethane, would that be considered a success?

Response:

Reduced consumption may be a possible outcome of customer education efforts, but it is not the primary objective of the biomethane customer education plan. The expressed purpose of the Biomethane Program is to inform customers of the opportunity to reduce their carbon footprint by reducing their consumption of traditional natural gas and replacing that consumption with carbon-neutral Renewable Natural Gas. If customer education results in awareness, participation and maintaining subscriptions in the program, then it will be considered a success. However, energy efficiency and conservation messaging is complementary to the program and is targeted at a similar energy and environmentally conscious customer base. The FEU, from a corporate standpoint, will continue to place a high priority on encouraging customers to customers to use energy as efficiently.

90.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.3.3

Under Spending in Energy Efficiency and Conservation Programs

90.1 Please provide the table in BCUC IR Response 1.3.3 with the amounts for Residential, Commercial, Joint Initiatives and CEO Programs as separate line items.

Response:

Tables 1 and 2 below have broken out the Residential category from BCUC IR 1.3.3 into the commercial, joint initiatives and CEO program categories requested in this IR. The two tables also breakdown expenditures into other categories used in the EEC Programs Annual Report so as to give a fuller picture of the Companies EEC expenditures for 2010 and 2011. The difference between the two tables is as follows:

- Table 1 below includes the 2010 actual and 2011 forecasted balances in the Energy Efficiency and Conservation deferral accounts, similar to what was presented in BCUC IR 1.3.3. In this table, deferral account projections are provided for residential, commercial, joint initiatives and CEO. The "residential" figures for FEI and FEVI projected spending for 2011 are not broken out by area of activity as they were not broken out for the deferral account projections for 2011. Table 2 shows 2010 committed expenditures as reported in the 2010 EEC Annual Report, filed as Appendix K-4 to Exhibit B-1. 2010 committed expenditures include both actual expenditures and expenditures where a customer has received a commitment of an incentive, but where that incentive has not yet been paid out by the end of 2010. The 2011 forecasted expenditures shown in Table 2 are also from the 2010 EEC Annual Report, which includes the breakdown amongst the Residential, Commercial, Joint Initiatives and CEO programs. The 2011 forecasts in the EEC Annual Report reflected in Table 2 are higher than the 2011 deferral account projections in Table 1, as the 2011 EEC expenditure forecast was refined over the time lag between when the deferral account forecasts were established for the RRA and the writing of the 2011 Annual Report. The FEU are not proposing to update the deferral account balances for the purpose of 2012-2013 rates, but would update the deferral account balance to actual expenditures in the next RRA.

The Companies believe that providing the funding levels that were committed as a result of 2010 EEC activity as shown in Table 2 gives a more accurate view of expected expenditures for this time period. Further, since the Companies did not break down Residential, Commercial, Joint Initiatives and CEO separately in their deferral account forecasts for 2011, the figures from the EEC Annual Report in Table 2 are a more useful reflection of the comparisons requested for the different areas of EEC activity.

The two tables reflect corrections required to the 2010 Approved and Actual totals from what was initially filed in BCUC IR 1.3.3:

- The 2010 Approved amount for Innovative Technologies in BCUC IR 1.3.3 inadvertently excluded $38 thousand of approved funding. The total 2010 Approved amount for EEC funding, as approved in BCUC Orders G-140-09 and G-141-09, was $31.049 million and not $31.014 million as indicated in BCUC IR 1.3.3.
- The 2010 Actual amount for Affordable Housing included $935 thousand that should have been allocated to the Joint Initiatives category. This explains the difference between the $725 thousand in 2010 Affordable Housing expenditures in the table below and the $1.660 million amount as shown in BCUC IR 1.3.3.
- Finally, the total Portfolio Level Activities embedded in the Residential, Commercial, Joint Initiatives and CEO Programs category excluded $64 thousand of expenditures. The total 2010 Actual amount for EEC funding was $12.653 million and not $12.599 million as shown in BCUC IR 1.3.3.

Table 1: EEC expenditures based on 2010 actual and 2011 forecasted deferral account additions[14],[15],[16],[17]

($000's)	FEI and FEVI Approved 2010	FEI and FEVI Actual Spending 2010	FEI and FEVI Approved 2011	FEI and FEVI Projected Spending 2011	FEI, FEVI and FEW Incremental Funding Proposed 2012	2012 Proposed Funding	FEI, FEVI and FEW Incremental Funding Proposed 2013	2013 Proposed Funding
Residential	3,572	3,463	3,572	14,728	5,928	9,500	5,928	9,500
Commercial	14,534	(99)	14,533	n/a	(33)	14,500	(33)	14,500
Joint Initiatives	1,648	615	1,648	n/a	(1,648)	-	(1,648)	-
CEO Programs	3,538	1,615	3,538	n/a	1,462	5,000	1,462	5,000
Affordable Housing	3,000	725	3,000	2,571	2,000	5,000	2,000	5,000
Industrial Interruptible	435	3	1,875	1,766	125	2,000	125	2,000
Innovative Technologies	2,812	3,017	5,625	735	5,875	11,500	5,875	11,500
New Initiatives	n/a	n/a	n/a	n/a	25,000	25,000	25,000	25,000
High-Carbon Fuel-Switching	1,510	299	1,510	n/a	490	2,000	490	2,000
Efficiency Partners	n/a	111	n/a	n/a	n/a	n/a	n/a	n/a
Portfolio Level Activities	n/a	2,904	n/a	n/a	n/a	n/a	n/a	n/a
Total	31,049	12,653	35,301	19,800	39,199	74,500	39,199	74,500

14 The incremental funding proposed for 2013 as compared to 2011

15 Commercial Program Area funding request rounded down by $33,000.

16 2010 actual figures include accrual reversals from 2009 and are presented on an accrual basis rather than a cash basis. The 2010 additions were used to calculate the opening 2011 balances in Section 7, Tabs 7.1 & 7.2, Schedule 66 of the 2012/2013 RRA

17 There is a credit showing in the table for incremental funding for Joint Initiatives for 2012 and 2013, and no value is provided for proposed funding for Joint Initiatives for 2012 and 2013 as the Companies have proposed consolidating Joint Initiatives funding and activity with Residential for 2012 onward.

Table 2: EEC expenditures including 2010 committed expenditures and 2011 forecasted expenditures as reported in 2010 EEC Annual Report[18],[19],[20]

($000's)	FEI and FEVI Approved 2010	FEI and FEVI Committed Spending 2010	FEI and FEVI Approved 2011	FEI and FEVI Forecasted Spending 2011	FEI, FEVI and FEW Incremental Funding Proposed 2012	2012 Proposed Funding	FEI, FEVI and FEW Incremental Funding Proposed 2013	2013 Proposed Funding
Residential	3,572	3,243	3,572	2,535	5,928	9,500	5,928	9,500
Commercial	14,534	2,570	14,533	3,264	(33)	14,500	(33)	14,500
Joint Initiatives	1,648	458	1,648	3,282	(1,648)	-	(1,648)	-
CEO Programs	3,538	1,616	3,538	3,538	1,462	5,000	1,462	5,000
Affordable Housing	3,000	123	3,000	2,571	2,000	5,000	2,000	5,000
Industrial Interruptible	435	-	1,875	1,766	125	2,000	125	2,000
Innovative Technologies	2,812	5,959	5,625	4,055	5,875	11,500	5,875	11,500
New Initiatives	n/a	n/a	n/a	n/a	25,000	25,000	25,000	25,000
High-Carbon Fuel-Switching	1,510	123	1,510	524	490	2,000	490	2,000
Efficiency Partners	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Portfolio Level Activities	n/a	3,226	n/a	7,131	n/a	n/a	n/a	n/a
Total	31,049	17,318	35,301	28,666	39,199	74,500	39,199	74,500

[18] The incremental funding proposed for 2013 as compared to 2011
[19] Commercial Program Area funding request rounded down by $33,000.
[20] There is a credit showing in the incremental funding for Joint Initiatives for 2012 and 2013, and no value is provided for proposed funding for Joint Initiatives for 2012 and 2013 as the Companies have proposed consolidating Joint Initiatives funding and activity with Residential for 2012 onward.

90.2 Please complete the following table based on the information provided in the table in response to the information request above.

	A	B	C	D	E	F
($000's)	**2010 actual spent ÷ 2010 approved spending (%)**	**2011 projected spending ÷ 2011 approved spending (%)**	**2011 projected spending ÷ 2010 actual spent (%)**	**2012 proposed funding ÷ 2011 approved spending (%)**	**2012 proposed funding ÷ 2011 projected spend (%)**	**2012 Program Area funding if 2011 over 2010 increase in spending applied to 2011 projected spending (Column C x FEI and FEVI Projected Spending 2011)**
Residential						
Commercial						
Joint Initiatives						
CEO Programs						
Affordable Housing						
Industrial Interruptible						
Innovative Technologies						
New Initiatives						
Total						

Response:

The FEU have provided the information requested in the two tables below; however, this method of analysis should not be used as a basis for setting EEC budgets as it would forecast budgets based on existing spending rather than on the potential for cost-effective DSM. It also assumes a static rate of growth in programs, which fails to consider whether programs would plateau or grow more quickly for various reasons.

The Companies believe that providing the committed funding levels, as shown in Table 2 of BCUC IR 2.90.1 provides a more useful comparison for the different areas of EEC activity for the purpose of this analysis. However, as can be seen by the results in column F of Table 2 below, the suggested analysis would unreasonably forego opportunities for cost effective DSM that the Conservation Potential Review shows exist, and would make unreasonable allocations of funding by Program Area. The Commercial sector, for example, offers the largest opportunity for Energy Efficiency and Conservation at approximately 4.2 million GJ/year in the Most Likely Achievable Scenario by 2030 as can be seen on pages 12 and 13 of the Conservation Potential Review ("CPR") Summary Report, filed as Appendix K-2 to Exhibit B-1. The Residential sector offers lower levels of opportunity at 3.5 million GJ/year. The analysis requested, however, shows in Column F of Table 2, that using the methodology outlined in the question above, Affordable Housing would be funded at over $50 million/year, while the Commercial sector would only be funded at around $4 million/year.

It should also be noted that this methodology indicates that the total funding envelope should be $115.4 million, nearly $41 million higher than the FEU's proposed amount of $74.5 million. The FEU continue to believe that the proposed funding envelope of $74.5 million is reasonable and appropriate for 2012 and 2013 as it is aligned with British Columbia's energy objectives.

Table 1 below calculates the ratios based on the first table in the response to BCUC IR 2.90.1, which was prepared based on the <u>actual</u> and projected balances in the Energy Efficiency and Conservation deferral account.

Table 1: Based on 2010 actual and 2011 projected deferral account additions

	A	B	C	D	E	F
($000's)	**2010 actual spent / 2010 approved spending (%)**	**2011 projected spending / 2011 approved spending (%)**	**2011 projected spending / 2010 actual spent (%)**	**2012 proposed funding / 2011 approved spending (%)**	**2012 proposed funding / 2011 projected spending (%)**	**2012 Program Area funding if 2011 over 2010 increase in spending applied to 2011 projected spending (Column C x FEI and FEVI Projected Spending 2011)**
Residential*	96.94%	63.23%	263.30%	265.96%	196.90%	38,779
Commercial	-0.68%	n/a	n/a	99.77%	n/a	n/a
Joint Initiatives	37.32%	n/a	n/a	n/a	n/a	n/a
CEO Programs	45.64%	n/a	n/a	141.32%	n/a	n/a
Affordable Housing	24.16%	85.70%	354.72%	166.67%	194.48%	9,120
Industrial Interruptible	0.76%	94.19%	53515.15%	106.67%	113.25%	945,078
Innovative Technologies	107.30%	13.07%	24.36%	204.44%	1564.63%	179
New Initiatives	n/a	n/a	n/a	n/a	n/a	n/a
High-Carbon Fuel-Switching	19.81%	n/a	n/a	132.45%	n/a	n/a
Total Efficiency Partners	n/a	n/a	n/a	n/a	n/a	n/a
Portfolio Level Activities	n/a	n/a	n/a	n/a	n/a	n/a
Total	n/a	n/a	n/a	n/a	n/a	993,155

*The "Residential" figure for 2011 projected deferral account additions includes Residential, Commercial, Joint Initiatives and CEO as these categories were not broken out to arrive at the deferral account addition projections.

Using the deferral account balance as the basis for this analysis does not provide reasonable results, as demonstrated by Column F of Table 1. This is because the balance in the deferral account includes effects from accruals and does not track projected EEC spending on a program basis. The FEU prepare their analysis of the actual program spending in conjunction with the EEC Annual Report in March of every year. As the Annual Report for 2011 has not yet been completed, the allocation amongst program areas for the 2011 projected deferral account balance, as shown in Table 1 of BCUC IR 2.90.1, is an approximation and the Residential, Commercial, Joint Initiatives and CEO have been grouped together in the Residential category. Thus, the Companies believe that providing the committed and forecasted funding levels from the Annual Report, as shown in Table 2 of BCUC IR 2.90.2, rather than the deferral account balance provides a more useful comparison for the different areas of EEC activity.

Table 2 below calculates the ratios based on the second table in the response to BCUC IR 2.90.1, which was prepared based on 2010's committed expenditures as reported in the 2010 Energy Efficiency and Conservation Annual Report, and the 2011 Forecast expenditures in the same report.

Table 2: EEC expenditures including 2010 committed expenditures and 2011 forecasted expenditures as reported in 2010 EEC Annual Report

	A	B	C	D	E	F
($000's)	**2010 committed / 2010 approved spending (%)**	**2011 projected spending / 2011 approved spending (%)**	**2011 projected spending / 2010 committed (%)**	**2012 proposed funding / 2011 approved spending (%)**	**2012 proposed funding / 2011 projected spending (%)**	**2012 Program Area funding if 2011 over 2010 increase in spending applied to 2011 projected spending (Column C x FEI and FEVI Projected Spending 2011)**
Residential	90.79%	70.97%	78.17%	265.96%	374.75%	1,982
Commercial	17.68%	22.46%	127.00%	99.77%	444.24%	4,145
Joint Initiatives	27.79%	199.15%	716.59%	n/a	n/a	23,519
CEO Programs	45.68%	100.00%	218.94%	141.32%	141.32%	7,746
Affordable Housing	4.10%	85.70%	2090.24%	166.67%	194.48%	53,740
Industrial Interruptible	zero spend	94.19%	n/a	106.67%	113.25%	3,532
Innovative Technologies	211.91%	72.09%	68.05%	204.44%	283.60%	2,759
New Initiatives	n/a	n/a	n/a	n/a	n/a	n/a
High-Carbon Fuel-Switching	8.15%	34.70%	426.02%	132.45%	381.68%	2,232
Total Efficiency Partners	n/a	n/a	n/a	n/a	n/a	n/a
Portfolio Level Activities	n/a	n/a	221.05%	n/a	n/a	15,763
Total	n/a	n/a	n/a	n/a	n/a	115,418

91.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 192.1

Under Spending in Energy Efficiency and Conservation Programs

"As the financial crisis eases, and as the Companies establish staffing levels more aligned with the degree of EEC activity made possible by the increased funding approval levels, more programs and initiatives will be developed and deployed, higher numbers of customers will participate in the FEU's programs and activities, and as a result, actual spending levels should meet approved expenditure levels."

91.1 FEU states three factors that resulted in the Companies not spending to approved levels in 2010 and 2011: human resourcing issues; the economic downturn; and the relatively low cost of gas. In the excerpt above, FEU does not factor low gas prices into its reasoning as to why actual spending levels should meet approved expenditure levels in 2012 and 2013. Please factor low gas prices into an explanation of why a higher numbers of customers will participate in FEU's programs and activities.

Response:

While low gas prices could continue to be a factor in EEC program participation, there are viable, cost-effective programs that can offer strong energy savings potential to customers even when taking into account low gas prices. As staffing levels grow to be more aligned with the degree of EEC activity made possible by increased funding approval levels, the Companies will have the resources available to develop, design and implement more of these programs. Putting more programs and activities into the marketplace will result in more opportunities for more customers to participate in more programs that offer strong energy savings. Due to the low cost of gas, the amount of participation in any individual program is lower than it would be if gas costs were higher. However, by offering more programs that offer different cost saving opportunities to a variety of different customers, more participation can be generated. As offering programs requires staffing to develop, design and implement them, one of the key factors limiting participation in the current low cost of gas environment has been human resourcing issues.

91.2 What evidence is the FEU relying on to say that the financial crisis is easing to a point where customers are willing to spend more of their constrained funds on energy efficiency and conservation? Please detail the evidence or provide it.

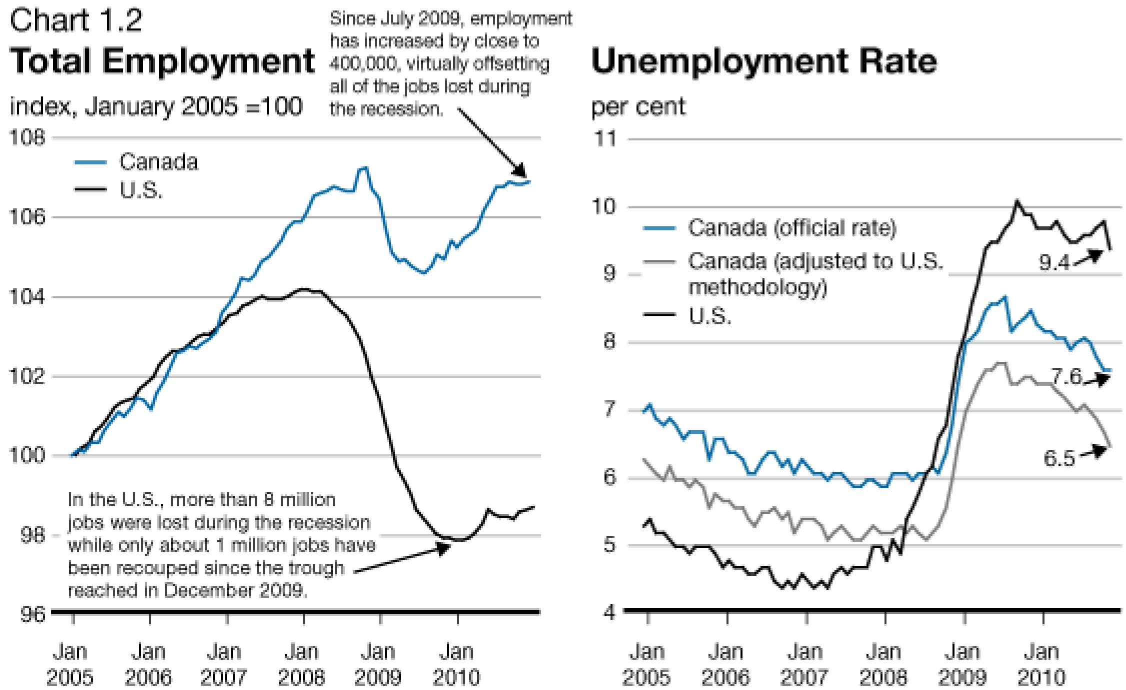
Response:

The Companies do not have any direct evidence to say explicitly that the financial crisis is easing to the point where customers are willing to spend more of their constrained funds on energy efficiency and conservation. The FEU have not, for example, conducted a customer survey asking specifically about customers' changing attitudes towards expenditures on energy efficiency and conservation. However as the following information makes clear, Canada's economy is recovering from the recent recession, and it is the Companies' view that it is reasonable to expect that customers will be more receptive to EEC activity now than they were in 2008, when the recession began. The following excerpt is from a document called, "Canada's Economic Action Plan", published by the Canadian federal Ministry of Finance in January, 2011.

> *"The economic recovery in Canada is continuing. Canada has weathered the global recession better than most other industrialized countries and is experiencing a solid recovery. Canada's performance both during the recession and over the recovery reflects continued financial, economic and fiscal strengths together with substantial support provided by monetary policy and Canada's Economic Action Plan. As a result, close to 400,000 more Canadians are working today than in July 2009—virtually offsetting all of the jobs lost in Canada during the global economic downturn (Chart 1.2). This labour market recovery contrasts sharply with labour market developments in the United States, where employment remains well below its pre-recession level.*
>
> *The unemployment rate in Canada fell from a peak of 8.7 per cent in August 2009 to 7.6 per cent in December 2010, its lowest level since January 2009."*[21]

Chart 1.2 from the same document shows unemployment rates falling, as the economy recovers:

[21] Source: http://www.fin.gc.ca/pub/report-rapport/2011-7/ceap-paec-1-eng.asp



Sources: Statistics Canada; U.S. Bureau of Labor Statistics.

This federal government document also states that private domestic demand is recovering:

> *"Reflecting the positive impact of the first phase of the Economic Action Plan on consumers and businesses, the recovery in economic activity is being underpinned by a rebound in private domestic demand—the sum of private consumption and business investment. Canada is the only G-7 country to have fully recouped private domestic demand lost during the recession."*

Again, given that private domestic demand which is comprised of private consumption and business investment – both categories of spending into which energy efficiency and conservation investments by individuals and companies would fall – has recovered to pre-recession levels, the Companies feel that it is reasonable to conclude that customers would be more open to energy efficiency and conservation activity now than over the past two years.

91.3 What evidence is FEU relying on to say that uncertainty about the direction of the provincial government negatively impacted customer focus on EEC by increasing customer uncertainty about the longevity of government programs such as LiveSmartBC? Please detail the evidence or provide.

Response:

The Companies do not have direct evidence that uncertainty about the direction of the provincial government negatively impacted customer focus on EEC by increasing customer uncertainty. However, it is reasonable to conclude that uncertainty about the government's overarching policy goals cause uncertainty in the energy efficiency marketplace, which includes customers, about the continuation of many government programs such as LiveSmartBC.

This appears to be illustrated by the cancellation of the federal government's eco-Energy program. The cancellation of the program was announced on March 31, 2010, and was effective the next day, from which date no new entrants into the program were accepted. In June 2009, when LiveSmartBC, the Home Renovation Tax Credit and eco-Energy were all in effect, the home renovation program saw 4,124 entrants. In June 2010, when only LiveSmartBC was in effect, the home renovation program saw 1,239 entrants, a 70% decline.[22] One reasonable explanation for this drop in participation levels is that customer behaviour is affected by uncertainty about incentives available.

91.4 Given that FEU states "it took significant amount of time to train new staff…[t]his delayed the development and deployment of new programs" and that FEU is planning on implementing new programs in 2012 and 2013 and that "[t]he Companies are currently in the process of increasing the staffing levels within the EEC group again", how can FEU forecast that the human resource factor, which caused the Companies to under spend in 2010 and 2011, will be reduced or eliminated in 2012 and 2013?

Response:

As noted in the response to BCUC IR 2.91.1, the Companies' existing EEC staff are already fully engaged with existing workloads. Increasing staffing levels by adding staff, as the Companies intend to do over the remainder of 2011, will reduce the potential that human

[22] These numbers were provided to FEU's EEC team by the LiveSmartBC team at the Ministry of Energy and Mines.

resource constraints will limit EEC spending as more staff means more programs for customers to participate in. Further, there is an expanded base level of EEC programs and resultant skill sets within the Companies from which to build going forward, which is different from 2009 and 2010.

91.5 What percentage of British Columbia's greenhouse gas emissions result from the utility energy sector? Please provide a comparison of British Columbia's greenhouse gas emissions by sector or industry.

Response:

For clarity, GHG emissions resulting from the utility energy sector is taken to mean those GHG emissions that are directly attributable to the utilities' core business of producing (in the case of electric utilities) and delivering useful energy products to consumers. Emissions generated by end-users who consume natural gas delivered by the FEU are provided for reference purposes at the end of this response.

This estimate of GHG emissions from BC's utility energy sector is based on the following two sources of data (both managed by Environment Canada):

a) The Greenhouse Gas Emissions Reporting Program (GHGRP): A "bottom up" approach which requires any facility with annual GHG emissions of 50 kilotonnes of carbon dioxide equivalent (kt CO_2e) or higher to report their emissions under the program. These data are provided for each reporting facility. Under this program six BC companies reported under the North American Industry Classification (NAICS) "utilities" [22]. The data for this NAICS group have been aggregated and are estimated to represent BC's "utility energy sector".

b) The National Inventory Report on Greenhouse Gases and Sinks in Canada (NIR): A "top down" approach which estimates annual GHG emissions at a sectoral and provincial/territorial level, based on national and provincial statistics, without attribution to individual emitters.

The latest year for which data are available from both sources is 2009.

According to the GHGRP, total emissions for the utility sector (NAICS category "22") in British Columbia were as follows:

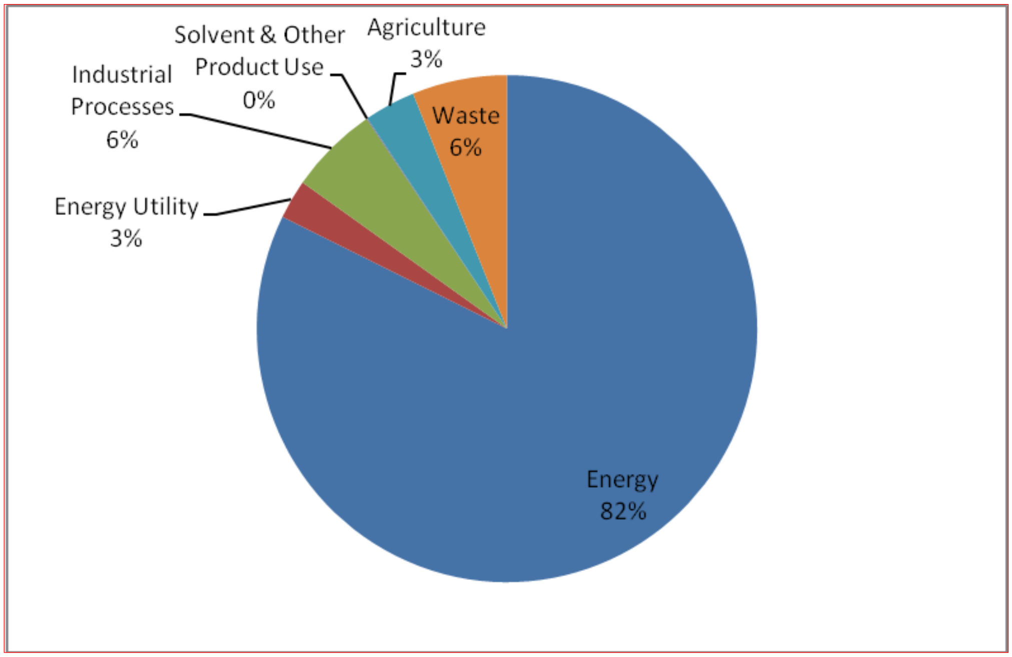
- Four BC power generation stations reported under NAICS code 2211, which includes "Electric Power Generation, Transmission and Distribution", for a total in 2009 of 1,443 kt CO_2e;
- Two BC companies reported under NAICS code 2212 "Natural Gas Distribution" for a total in 2009 of 162 kt CO_2e. The two reporting companies were FortisBC Holdings Inc. (then Terasen Inc.) subsidiaries, which under the Environment Canada reporting facility definition must report on emissions for their entire natural gas transmission, distribution and storage system installations.

In total, the NAICS utility category ["22"] totalled 1,605 kt CO_2e. Significantly, emissions from facilities producing less than 50 kt of GHG emissions per year are not included in this total. Also note that Pacific Northern Gas did not report.

In the NIR, all GHG emissions from stationary and transportation fuel combustion activities as well as fugitive emissions from the fossil fuel industry are captured under the Energy sector. As such, energy utility emissions are included in the Energy category. Unfortunately emissions from utilities are not discretely estimated, and thus cannot be determined from NIR data. The NIR data can however be used in conjunction with GHGRP data to illustrate the magnitude of utility sector emissions versus those of other sectors in the province.

The Companies believe that, though imperfect, the total reported under the GHGRP is a reasonably representative estimate of emissions resulting from the utility energy sector in the province of British Columbia.

The following chart has been prepared to provide a comparison of BC GHG emissions by Sector in 2009. Energy utility sector emissions, as identified in the GHGRP, have been broken out from the other Energy sector emissions, as estimated in the NIR.



For a more detailed comparison of BC's GHG emissions by sector please refer to Table A15-21 2009 GHG Emission Summary for British Columbia, National Inventory Report, 1990-2009 – Part 3, pg. 98, available at:

http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2011-nir-16may.zip

For reference, the FEU delivered approximately 201,720,000 GJ of natural gas and 580,000 GJ of propane to consumers in 2009. GHG emissions resulting from the combustion of natural gas are approximately 0.05 tonnes of CO2e per GJ, while those from propane are approximately 0.0597 tonnes of CO2e per GJ. Thus, in 2009, the consumption of natural gas and propane by end users generated approximately 10,121 kilotonnes of CO2e in British Columbia.

92.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 192.2

Under Spending in Energy Efficiency and Conservation Programs

"It can be expected that the ramp up in activity would take time as new programs are established and become known to the marketplace, as well as establishing the support to create and sustain them... The largest part of the increase comes from the 'New Initiatives' which are budgeted at $25 million per year and form one-third of the overall funding envelope."

92.1 Given the statement above regarding the time for programs to ramp up and become known in the marketplace, please justify the request for $25 million for each of 2012 and 2013 for three new programs FEU has not run before.

Response:

The FEU believe that the three programs requested under New Initiatives are each possible to develop and initiate in a timely fashion based on the experience and competencies of EEC staff that have been established over the past two years. EEC staffing levels and expertise have increased significantly since the FEU's expanded EEC initiative was approved in mid-2009 by BCUC Order No. G-36-09. The FEU note that the request for funding for the New Initiatives in this Application is contingent on other conditions or approvals being in place, such as BCUC approval to use the SCT in EEC evaluations or provincial amendments to the DSM Regulation. Further, the FEU's proposed treatment of only including $20 million/year of EEC spending in the 2012-2013 rates, and deferring (with AFUDC) actual spending in excess of $20 million/year for recovery commencing in 2014, means that natural gas ratepayers will only be charged for actual spending levels on the New Initiatives and will not be negatively impacted if ramping up of program activities takes longer such that spending is less than the applied-for funding envelope of $25 million per year.

93.0 Reference: Energy Policy Deferral Accounts

Exhibit B-9, BCUC IR 1.106.1

Energy Efficiency and Conservation Programs

93.1 Please complete the FEU Rate Base Deferral Account Amortization of 2012 and 2013 EEC Additions table showing the account balance if additions of $20.0 million per year are made to the EEC rate base deferral account in each of the years from 2012 to 2023.

Response:

The following table shows the continuity for the EEC rate base deferral account for 2012 through 2023, assuming $20.0 million in additions at each year with an amortization period for the account of 10 years. For simplicity, a tax rate of 25% was assumed each year. The FEU note that the deferral account balance remains constant starting in 2021, when the forecasted additions become equal to the forecasted amortization expense.

FEU Rate Base Deferral Account
Amortization of 2012-2023 EEC Additions
$ Thousands

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Opening Balance	-	15,000	28,500	40,500	51,000	60,000	67,500	73,500	78,000	81,000	82,500	82,500
Gross Additions	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Tax	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)
Net Additions	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Amortization Expense	-	(1,500)	(3,000)	(4,500)	(6,000)	(7,500)	(9,000)	(10,500)	(12,000)	(13,500)	(15,000)	(15,000)
Closing Balance	15,000	28,500	40,500	51,000	60,000	67,500	73,500	78,000	81,000	82,500	82,500	82,500

93.2 Given that the balance in this deferral account increases every year from 2012 to 2023, please explain FEU's plan for recovery of the balance of this deferral account.

Response:

The balance in the deferral account does not increase every year from 2012 to 2023. As demonstrated in the response to BCUC IR 2.93.1, under the scenario where $20 million in rate base additions continues each year until 2023, the balance in the EEC deferral account levels off by the year 2021.

At this time, the FEU continue to believe that the balance in the EEC rate base deferral account should be amortized over 10 years through delivery rates as approved in Commission Order G-36-09.

To be clear, in this RRA the FEU have not proposed that the 2012 and 2013 EEC funding amounts or rate base additions continue in perpetuity. The EEC program is reviewed on a regular basis and FEU may seek changes to the level of the EEC funding envelope in future revenue requirements or long term resource plan applications, in accordance with the success of the program and the achievement of energy efficiency and conservation targets. Furthermore, as discussed in the response to BCUC IR 1.6.1, the FEU review deferral account balances on a regular basis and through our rate setting processes and annual reporting, report on actual and forecast balances in deferral accounts to the Commission.

93.3 Please provide a similar table showing the balance of the proposed EEC Incentive Non-rate Base Deferral Account in the years 2012 to 2023 if the proposed level of EEC spending ($74.5 million) is approved and spent.

Response:

To be clear, in this RRA the FEU have not proposed that the 2012 and 2013 EEC funding amounts continue in perpetuity. The EEC program is reviewed on a regular basis and the FEU may seek changes to the level of the EEC funding envelope in future revenue requirements or long term resource plan applications, in accordance with the success of the program and the achievement of energy efficiency and conservation targets. Furthermore, as discussed in the response to BCUC IR 1.6.1, the FEU review deferral account balances on a regular basis and through our rate setting processes and annual reporting, report on actual and forecast balances in deferral accounts to the Commission.

Under the scenario proposed in this question, if an annual funding envelope of $74.5 million is approved and spent for 2012-2023, it would result in an annual rate base deferral account addition of $20.0 million and an annual non-rate base deferral account addition of $54.5 million. The following table shows the continuity for the EEC non-rate base deferral account for 2012 through 2023, assuming $54.5 million in additions each year. The underlying assumptions to this table include:

- Income tax rate of 25% for 2012-2023.
- 2012 and 2013 AFUDC rates are as per Table 6.1-11 of the Application.
- From 2014 onwards, no AFUDC is calculated while amortization expense is calculated, mirroring the treatment of a rate base deferral account for simplicity. This approach was proposed in BCUC IR 1.104.2 as one method of amortization recovery.

FEU Non-Rate Base EEC Deferral Account
Amortization of 2012-2023 EEC Additions
$ Thousands

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Opening Balance	-	42,709	89,214	121,167	149,033	172,812	192,503	208,107	219,623	227,052	230,393	229,646
Gross Additions	54,500	54,500	54,500	54,500	54,500	54,500	54,500	54,500	54,500	54,500	54,500	54,500
Tax	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)	(13,625)
AFUDC	1,834	5,629										
Net Additions	42,709	46,504	40,875	40,875	40,875	40,875	40,875	40,875	40,875	40,875	40,875	40,875
Amortization Expense	-	-	(8,921)	(13,009)	(17,096)	(21,184)	(25,271)	(29,359)	(33,446)	(37,534)	(41,621)	(41,438)
Closing Balance	42,709	89,214	121,167	149,033	172,812	192,503	208,107	219,623	227,052	230,393	229,646	229,083

93.3.1 Please explain FEU's plan for recovery of the balance of this deferral account.

Response:

As outlined in Section 6.3.2.1 of the Application, the FEU are seeking to recover the balance in the non-rate base EEC deferral account over a ten-year period beginning in 2014. However, as discussed in the response to BCSEA IR 1.11.1, the method of recovery for the non-rate base EEC deferral account will be determined as part of the FEU's next revenue requirements application. The FEU will evaluate the appropriate recovery method based on the balance of the account(s) and the regulatory and rate structure in place at that time. Transferring the balance from the EEC non-rate base deferral account to the EEC rate base deferral account is a likely recovery alternative that the FEU will consider.

To be clear, in this RRA the FEU have not proposed that a funding envelope of $74.5 million per year pertaining to the EEC program continues in perpetuity. The EEC program is reviewed on a regular basis and the FEU may seek changes to the level of the EEC funding envelope in future revenue requirement or long term resource plan applications, in accordance with the success of the program and the achievement of energy efficiency and conservation targets. Furthermore, as discussed in the response to BCUC IR 1.6.1, the FEU review deferral account balances on a regular basis and through our rate setting processes and annual reporting, report on actual and forecast balances in deferral accounts to the Commission.

93.4 Please demonstrate, through calculation and summarize the overall rate impact for FEI if EEC funding in 2012 and 2013 remained consistent with 2011 and compare this with rate requests in this Application.

Response:

FEI interprets this question to be asking for a comparison using the 2011 approved EEC additions of $29.6 million, rather than the 2011 projected EEC additions of $17.8 million, and applying the $29.6 million to the 2012 and 2013 forecast. The overall rate impact is then determined by comparing the new 2012 and 2013 forecasts to the existing 2011 approved amount.

As shown in the table below, if the EEC rate base deferral account additions remained at the approved 2011 level of approximately $29.6 million (before-tax), changes to the balance in the FEI EEC rate base deferral account would offset the revenue deficiency in 2012 with a revenue surplus impact (i.e. rate decreasing impact) of $0.3 million and would contribute approximately $4.7 million to the revenue deficiency in 2013 (cumulative revenue deficiency of $4.4 million in 2013), when compared to existing approved 2011 delivery rates. This compares unfavourably to the impact of the rate request in this Application, as shown in the response to BCUC IR 1.2.1, of a $0.7 million surplus in 2012 and $2.7 million incremental deficiency in 2013.

Further, the delivery rate impacts of -0.06% in 2012 and 0.82% in 2013 (0.76% cumulative 2013 impact) shown in the table below compare unfavourably to the impacts in this Application, as shown in the response to CEC IR 1.1.2, of -0.13% in 2012 and 0.48% in 2013 (0.35% cumulative 2013 impact).

EEC Additions Scenario: Maintain 2011 Approved Level of $29.6 million (before-tax)
($000s)

Rate Base	2011 Approved	2012 Forecast	2013 Cumulative Forecast
Opening Deferral Balance	23,837	21,177	40,830
Additions (net of tax)	21,770	22,214	22,214
Amortization	(2,525)	(2,561)	(4,836)
Ending Deferral Balance	43,083	40,830	58,208
Mid-Year Deferral Balance	33,460	31,004	49,519
Utility Income and Earned Return			
Amortization	2,525	2,561	4,836
Tax Expense	1,369	1,246	2,239
Earned Return	2,652	2,403	3,838
Revenue Requirement	6,546	6,210	10,914
Incremental Revenue Deficiency		(336)	4,703
Cumulative Revenue Deficiency		(336)	4,367
Incremental Delivery Rate Impact		-0.06%	0.82%
Cumulative Delivery Rate Impact		-0.06%	0.76%

94.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.1

Confidentiality Request

"The EEC working spreadsheet models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers."

94.1 Please list the specific differences between these spreadsheets filed confidentially and the spreadsheets provided in PDF format in Appendix B of the FEI/FEVI 2010 EEC Annual Report.

Response:

BCUC IR 1.189.1 requested working electronic models (emphasis added). The spreadsheets provided in PDF format in Appendix B of the 2010 EEC Annual Report are prints from the "plan" tabs on the working electronic spreadsheets provided confidentially in response to BCUC IR 1.189.1, and do not include the "input" sheets, nor the individual measure sheets. Further, BCUC IR 1.189.1 requested the results of the Societal Cost Test, which were provided in the working models submitted confidentially, while the PDF's in Appendix B of the 2010 EEC Annual Report reflect TRC results.

94.2 As the FEI/FEVI 2010 EEC Annual Report is a public document, please justify the request to file the spreadsheets attached to BCUC IR 1.189.1 confidentially.

Response:

It is the "working electronic" nature of the spreadsheets, rather than the spreadsheet outputs, that has caused the FEU to file these spreadsheets confidentially. These complex spreadsheets were developed by consultants at significant expense and it is the Companies' view that they are proprietary in nature. The Companies do not believe that the working versions should be made available publicly.

94.3 Please list the specific sections of the spreadsheets filed confidentially that are propriety in nature.

Response:

Please see the response to BCUC IR 2.94.1 and BCUC IR 2.94.2. It is the working version of the spreadsheets that the Companies would like to maintain as confidential.

94.4 Please propose sections of the spreadsheets to be redacted or a version of the spreadsheets with redactions so FEU can file the spreadsheets as public exhibits.

Response:

Attachment 94.4 contains PDF outputs of all the tabs in all of the spreadsheets.

95.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.191.1

2012-2013 EEC Funding Request

"For 2012 and 2013, the Companies have not yet developed detailed program plans which would include projections of energy savings; therefore information has not been provided for these years."

95.1 If the 2012-2013 EEC Funding request is approved, will ratepayers not be paying, through rates, for the energy savings or avoided energy use caused by the EEC programs? If not, what are the ratepayers paying for? If so, how can the Commission consider the ratepayer interest without knowing the projected energy savings for programs?

Response:

It is correct that customers will be paying, through rates, for the Companies' EEC activities, which will result in energy savings and other system benefits such as increased throughput through programs promoting energy efficient fuel switching from a higher carbon fuel to a lower carbon fuel. The Companies have proposed a Societal Cost Test to take into account societal benefits beyond energy savings that are also of value of ratepayers. The Companies believe that its proposed Societal Cost Test is an appropriate measure for considering ratepayer interest as ratepayers are also members of society. (The Companies note that with the proposed changes to the deferral account mechanism, the majority of the forecast EEC funding is captured on an as spent basis in a non-rate base deferral account. Therefore, of the $74.5 million EEC funding envelope request, only $20.0 million will be included in 2012 and 2013 delivery rates.)

When providing information on EEC funding for program areas, the Companies have projected and assessed the impact of energy savings and/or avoided energy use. For example, energy savings information is reported for all 2009 and 2010 programs and 2011 planned programs in the 2009 and 2010 EEC Annual Reports, filed as Appendices K-3 and K-4 to Exhibit B-1. As noted, at the time of writing, the detailed program design which would enable the Companies to make projections regarding energy savings for 2012 and 2013 has not yet been completed. The Companies will complete this work for 2012 in the fall of 2011, and will present the more detailed program projections to the EEC Stakeholder Group in the semi-annual meeting in late November/early December of 2011. During this meeting, FEU EEC staff will provide EEC Stakeholders with program descriptions and budgets including forecasts of energy savings, and program benefit-cost test forecasts, and the stakeholders which include customer/ratepayer groups will have the opportunity to provide input on any programs that they feel do not provide value. The portfolio will be managed to achieve a cost-effectiveness ratio of 1.0 or greater, providing value to customers and to society. Further, all program information including energy savings and benefit-cost test results for the upcoming year is provided in the Companies’ EEC Annual Report, which will be filed by the end of Q1 2012. That said, in 2010, the Companies committed $11.737 million to “conventional” EEC activity with associated annual savings of 166,110 GJ/year. If the Companies increase associated annual energy savings proportional to the increase in funding from 2010 to 2012, that proportional energy savings increase would result in annual energy savings of 1.05 million GJ/year for 2012 This proportional energy savings figures is intended to be for illustrative purposes only.

This approach to program design is consistent with Commission Order G-36-09 and particularly with the accountability measures established within the Order for refining EEC programs. What the Companies seek approval for in the Application is a total funding envelope for EEC activity, which is comprised of various program areas that have been or are to be accepted by the Commission. While the amount of the expenditure schedule reflects the sum of the Companies’ budget requests for the individual approved Program Areas, the FEU retain the flexibility to re-allocate funding within the overall portfolio with the objective of improving the benefits achieved by the overall EEC portfolio, and to add, modify or discontinue programs within a Program Area and to re-allocate funding with the objective of improving the benefits of the overall EEC portfolio.

96.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.196.4, 1.211.4

2012-2013 EEC Funding Request

"…in the case of the Commercial program area, no increase has been budgeted." (196.4)

"The Utilities are currently engaged in several initiatives aimed at capturing natural gas savings associated with [O&M, advanced building automation/retrocommissioning, high efficiency boilers and low-flow plumbing fixtures for the commercial sector]. "

96.1 Are the budgets associated with O&M, advanced building automation/retrocommissioning, high efficiency boilers and low-flow plumbing fixtures included in the $14.5 million budgeted for each of 2012 and 2013 for the Commercial Program Area.

Response:

Yes, budgets for the initiatives aimed at the above noted measures are included under the proposed $14.5 million in funding for the Commercial Program Area. The proposed funding represents the budgeted expenditure for the Commercial Program Area.

97.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.1

TRC Inputs

97.1 Please provide the following information for every 2011 EEC program and proposed 2012 EEC program in the following format:

Program Name	***Example: Energy STAR Heating System Upgrade _Fortis (Retrofit)***
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ):	*11.1*
Energy Savings Determination Methodology	1. Give a description of the baseline and efficient technologies, their assumed efficiencies, and the data source used to derive their efficiencies. For retrofit measures, give the efficiencies and data sources of the existing unit, the efficient unit, and the standard unit. 2. Give any algorithms or engineering analyses used to determine savings. 3. List the data and sources of data (e.g. DEER, ASHRAE etc.) reviewed to determine the savings per installation. 4. List the range of savings considered. 5. List any assumptions made in choosing the energy savings per measure. 6. Provide the energy savings per installation used by other utilities including Enbridge Gas, Union Gas, BC Hydro and Manitoba Hydro (where applicable) and any other applicable utilities. 7. Provide any impact evaluations or measurement and verification studies completed by FEU on this program. 8. If a code or standard is in place for the measure, provide the calculation showing how the proposed energy savings per measure was determined.
Measure Lifetime (years)	*18*
Measure Lifetime Determination Methodology	1. List the data and sources of data reviewed to determine the measure lifetime. 2. List the range of measure lifetimes considered. 3. List any assumptions made in choosing the measure lifetime. 4. Provide the measure lifetime used by other utilities including Enbridge Gas, Union Gas, BC Hydro and Manitoba Hydro (where applicable) and any other applicable utilities.
Incremental Cost ($)	*$100*
Incremental Cost Determination Methodology	1. List the data and sources of data reviewed to determine the incremental cost. For retrofit measures, give the full installed cost (including labor) of both the standard unit and the efficient unit. 2. List the range of incremental costs considered. 3. List any assumptions made in choosing the incremental cost. 4. Provide the incremental cost used by other utilities including Enbridge Gas, Union Gas, BC Hydro and Manitoba Hydro (where applicable) and any other applicable utilities.

Response:

FEU has endeavoured to provide the best available information for existing Residential, Commercial, Industrial, Affordable Housing and Innovative Technologies program areas to meet this request in Tables 1 through 5, below. Gathering inputs and assumptions required for program design varies between programs and program areas based on the stakeholders involved, available industry data, government policies and regulation, customer type and the technologies applied. As such, some of the inputs and assumptions are not available in the format requested by the Commission. Further, the table has not been completed for future programs under consideration or for programs that are currently in development stages for 2012, as much of the requested data is not yet available for those programs.
As FEU gains history and experience with each of its programs, additional data will become available with which to consider, analyze and report in greater detail on the information the Commission is seeking. To provide greater detail than is reported in the table below at this point in the development of our programs and program evaluation practices will require substantial effort, cost and time.

Residential Programs:

In developing Residential Programs, the FEU conducts extensive research in order to provide inputs into economic analysis. Research most commonly used includes: studies conducted by third party experts such as Habart Consulting and Marbek (Conservation Potential Reviews - 2006 and 2010), the 2008 Residential End Use Study, NRCan, ENERGY STAR, the Consortium for Energy Effieciency, ESource, government partners, and other utilities. Trade allies including manufacturers, contractors and distributors provide information on measure life and incremental costs. As the residential program area evolves, the FEU will have the opportunity to conduct more in-depth evaluation studies, in order to provide more insight into the attribution of savings as the FEU promotes the market transformation of energy efficient appliances to their residential customers.

Measure descriptions are based on the following assumptions.

- Baseline technology is the lower (and generally cheaper) technology readily available in the market.
- Efficient technologies are those eligible for an incentive. The difference in performance between the baseline and the efficient technology provides the energy savings estimate.

In retrofit situations the existing unit is the one that is replaced. It represents technology that may be 15 -25 years old. The efficient unit is the incentive-eligible product, and the standard unit is assumed to be the baseline.

Table 1: Residential EEC Program Information

Residential Program (1.1)	**EnerChoice Fireplaces (Retrofit)**
Energy Savings per Installation (GJ)	7.8 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Baseline technology: all hearth products not rated as Enerchoice as described below. These appliances are primarily decorative units, intended for occasional use, not for heating purposes. b. Efficient technology: Enerchoice can only be applied to **free-standing stoves** that are 66% FE or higher, **fireplaces** that are 62.4% FE or higher and **inserts** that are 61% FE and higher. ("FE" = Fireplace Efficiency) as described at www.enerchoice.org c. Standard technology: the same as baseline technology. 2 and 3. Data Sources/Engineering analysis a. Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates b. 2009 Home Energy modeling study for LiveSmart BC Program (Habart and Hood Consulting) c. The 2010 Conservation Potential Review 4. Range considered: 3 GJs for an electrically heated apartment up to 9.4 GJ in a natural gas heated Single Family Dwelling. 5. Assumptions: Based on the evaluation of a 2004 Terasen Gas Fireplace Pilot Program. This program replaced decorative log sets with an insert that was rated at 55% efficient or higher. Upon completion, an evaluation was undertaken to estimate the likely impact of the program based on engineering estimates. Fireplace sizing was based on discussions with industry personnel, while seasonal hours of use were based on a survey of program participants. HOT2000 was used to estimate the interactive effects between the fireplace and the central space heating system. Actual numbers will depend on hours of use by program participants and dwelling type. 6. Annual energy savings No other Canadian utilities have a fireplace program. Both Enbridge and Union Gas have contacted FEU regarding

	assumptions used in program design as they are considering introducing fireplace programs. Pacific Gas and Electric offer a fireplace incentive based on Canadian ("P4") or EnerChoice efficiency rating; however, FEU does not have access to their program inputs at this time. 7. Impact Evaluations: a. Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates. b. Further impact evaluation to be conducted in 2012 now that that sufficient participation and heating seasons have taken place and the savings estimate will be adjusted accordingly. 8. Code and standard not applicable to savings claims: The Hearth Industry through Hearth Patio and Barbeque Association ("HPBAC") is self-regulated at this time. The Industry must assure Ministry of Energy and Mines that EnerChoice education is in place for dealers and customers and that hearth products are labeled with an EnerGuide rating in showrooms. The DOE is proposing upcoming efficiency standards that the FEU will monitor for future program development.
Measure Lifetime (years)	15 years
Measure Lifetime Determination Methodology	1. Data Sources: a. Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates b. 2006 and 2010 Conservation Potential Reviews c. Capturing age of replaced fireplace on program application forms to ensure a reasonable estimate of measure life. 2. Range considered: 15 – 20 years 3. Assumption: At 15 years, 92% of fireplaces were still operational suggesting that 15 years is conservative. 4. Measure life - other utilities: not applicable
Incremental Cost ($)	$150 - $250
Incremental Cost Determination Methodology	1. Data Sources: a. Hearth Manufacturers – based on the manufacturer's cost of installing energy efficient technology. 2. Range of incremental cost: $150 - $250 3. Assumption: Efficiency features are not directly correlated to price of the appliance. Features such as hearth décor influence price more than efficiency. 4. Other utilities: not applicable
Residential Program (1.2)	**Efficient Storage Tank Water Heater Program (>=0.62 EF) (Retrofit)**
Energy Savings per	2.0 GJ

Installation (GJ)	
Energy Savings Determination Methodology	1. Measure Description: a. Baseline technology: Basic hot water storage tank water heaters with a standing pilot light. b. Efficient technology: Similar to baseline technology but with improved insulation and features such as heat trap to reduce standing losses. c. Efficiency level of existing unit: 0.57 or 0.58 EF (EF=Energy Factor) d. Efficiency level of the efficient unit: ≥0.62 EF as outlined in MEMPR Enforcement Bulletin 09-05. BC Energy Efficiency Act Standards. Gas and Propane-Fired Water Heaters e. Efficiency level of the standard unit: 0.57 or 0.58 EF and moving towards 0.62 EF as market reaches 100% compliance 2 and 3. Data Sources/Engineering analysis: a. Canadian Residential Water Heater Market Assessment, prepared by Caneta Research for MEMPR in 2009, determined that a 0.58EF natural gas hot water heater consumes 29.19GJs/year in comparison to 27.28 GJs/year per 0.62EF natural gas water heater for a savings of 1.91 GJ. b. Habart's 2010 Market Transformation Domestic Water Heater Strategy prepared for FortisBC (Appendix I, 2009 EEC Annual Report) estimated that a 0.57EF natural gas water heater consumes 20.4 GJs/year in comparison to 18.5 GJs/year per 0.62EF natural gas water heater for a savings of 1.9 GJ. 4. Range considered: 1.9 GJ (0.62 EF) – 3.4 GJs (0.67 EF) 5. Assumptions: Refer to # 2. 6. Annual energy savings Other Canadian utilities are not offering a 0.62 EF water heater program at this time. Efficiency Nova Scotia offers incentives for switching from electric water heaters to gas water heaters, but not for replacing a gas hot water heater with a more efficient one. 7. Impact evaluation: Currently, the FEU are conducting a pilot to validate energy savings claims for Hot Water Heater technologies (0.80 EF) as part of a market transformation strategy and are considering using similar protocols to conduct impact evaluation in 2012 for the ≥0.67 EF tier. 8. Code and Standard: BC Energy Efficiency Act Standards. MEMPR information bulletin 09-05 re 0.62 EF minimum for 40 Gallon tanks. Savings estimates are based on incremental savings from standard tanks (0.57 / 0.58 EF tanks) since the BC market is not yet fully compliant.
Measure Lifetime (years)	13 years

Measure Lifetime Determination Methodology	1. Data Sources: a. Caneta Research for MEMPR, Long Term Regulation, 4.2, Nov 2008 b. Feedback from water heater manufacturers c. Capturing age of replaced appliance on program application forms to ensure a reasonable estimate of measure life. 2. Range of measure: 10-15 years 3. Assumption: Based on water heater age profile in 2008 REUS study and feedback from manufacturers. 2010 program participant average age of replaced water heaters was 14 years. 4. Other utilities: not applicable
Incremental Cost ($)	$100
Incremental Cost Determination Methodology	1. Data Sources: a. Hot Water Tank Manufacturers and distributors b. The full cost of installed standard water heater (0.57 EF): $1,155 (Habart research, 2009) c. The full cost of installed 0.62EF water heater: $1,238 (Habart research) 2. Range of incremental cost: $15 - $85 for upgrade to 0.62 and $300 for some Power Vent models that are higher EF according to FEU discussions with manufacturers and distributors. 3. Assumptions: $100 is conservative estimate for incremental cost of upgrading from 0.58 EF to 0.62 EF. Differentiation in consumer price is often attributed to product warranty rather than efficiency. 4. Incremental cost - other utilities: not applicable
Residential Program (1.3) (Joint Initiative)	**ENERGY STAR® Select Tier 3 Washing Machine Rebate**
Energy Savings per Installation (GJ)	3 GJ
Energy Savings Determination Methodology	1. Measure Description: Note: The most energy and water efficient models will have the highest Modified Energy Factor ("MEF") value and the lowest Maximum Water Factor ("WF") rating). Incentive eligible washers are select Tier 3 as outlined in the 2010 EnerGuide Appliance Directory – NRCan EcoEnergy a. Baseline: Non- ENERGY STAR models generally Top Load b. Efficiency level of 14 year old replaced unit is: not known c. Efficiency level of efficient unit is: MEF ≥2.4; WF<4. Efficiency level of current ENERGY STAR is: MEF ≥1.8; WF<7.5

	d. Efficiency level of 2007 ENERGY STAR is: MEF ≥1.72; WF<8.0 2 and 3 Data Sources/Engineering analysis: a. 3 GJ savings based on Marbek 2010 Conservation Potential Review b. BC Hydro Clothes Washer Technology Analysis provides electrical savings which when converted to natural gas would be approximately 1.6 GJ (given efficiency conversion from electric to natural gas). c. MEF and WF clothes washer efficiencies based on the 2010 EnerGuide Appliance Directory. 4. Range of savings: 1-3 GJs 5. Assumptions: Natural gas savings are based on water savings achieved with the new technology and electrical savings reflects both water savings and reduced drying time. Although extensive analysis has been conducted on electrical savings, further analysis is required for natural gas savings. FEU will undergo impact analysis in 2012 if the program is to remain in market. 6. Energy savings - other utilities: a. Enbridge Gas: not applicable b. Union Gas: pending request c. BC Hydro: Program partner d. Efficiency Nova Scotia: 0.87GJ (conversion from electric savings) per Tier III washer 7.. Code and Standard: a. Canada's Energy Efficiency Regulation regulate the minimum energy factor (based on the test standard (CAN/CSA-C360-92, CAN/CSA-C360-03 (Canada) and CAN/CSA C360-93 (Ontario)) to be 18.40 L/kWh/cycle or greater for compact and 35.68 L/kWh/cycle for standard clothes washers. b. On July 1, 2009, the ENERGY STAR® criteria for qualified clothes washers changed to MEF = 50.97 L/kWh/cycle (1.8 ft3/kWh/cycle). In addition, a maximum water factor (WF) was introduced as WF = 1.0 L (7.5 gal/cycle/ft3) with effective date as of July 1, 2009.
Measure Lifetime (years)	14 years
Measure Lifetime Determination Methodology	1. Data Sources: a. 2010 Conservation Potential Review b. Ontario Power Authority "2010 Prescriptive Measures and Assumptions: Release 1." 2. Range of measure life: BCHydro and Ontario Energy Board use 14 years and therefore range was not considered. 4. Measure lifetime - other utilities:

	a. Enbridge Gas: not applicable b. Union Gas: pending request c. BC Hydro: 14 years d. Efficiency Nova Scotia: Undetermined
Incremental Cost ($)	$350
Incremental Cost Determination Methodology	1. Data Sources: a. 2010 Conservation Potential Review b. BCHydro research c. The full cost of standard unit: $450 d. The full cost of efficient unit: $750 2. Range of incremental cost: $300-$350 3. Assumptions: Based on market research of average costs of select Tier 3 appliances over standard units. 4. Incremental cost - other utilities: a. Enbridge Gas: not applicable b. Union Gas: pending request c. BC Hydro: $350 d. Efficiency Nova Scotia: undetermined
Residential Program (1.4) (Joint Initiative)	**Live Smart BC**
Economic Modeling for the LiveSmart BC program was conducted in collaboration with BCHydro, FortisBC and Ministry of Energy and Mines. Innes Hood Consulting and Habart and Associates provided the natural gas and electric housing archetype and assumptions for Hot 2000 modeling which provided energy savings estimates in the Lower Mainland and Interior. Measure lifetime(s) were provided by BCHydro. Measure costs were provided by Hood in discussions with trade allies as to current measure costs. Window costs were developed in consultation with window manufacturers. Full Impact Evaluation will be available in Fall 2012 as led by BCHydro evaluation team with funding provided by utility partners. The following table outlines the costs and savings estimates used for the Lower Mainland inputs for economic modeling.	

Measure	Savings	Measure Cost
	NG [GJ]	$'s
AIR SEALING AND DRAFT PROOFING		
Air sealing 25% improvement over base	7.6	$1,000
Air Sealing 15% improvement over base	3.6	$500
Weighted Average	**6.1**	**$855**
ATTIC INSULATION & FLAT ROOF		
a. R0 to R50 - attic	38.3	$1,800
b. R6 to R50- attic	9.7	$1,400
c. R12 to R50 -attic	6.9	$1,100
d. R20 to R50 -attic	3	$900
e. R28 to R50-attic	1.5	$700
f. R0 to R14 - Flat roof	33.5	$1,205
g. R12 to R 28- Flat roof	6.2	$603
h. R28 to R50- Flat roof	1.3	$344
Weighted Average	**14.3**	**$1,199**
EXTERIOR WALL INSULATION		
a. R0 to R12 -RSI 0.64 =Add R9 for 100%	50.6	$3,945
b. R0 to R12 - RSI 0.78 = Add R9 for 100%	37.1	$3,945
c. R0 to R12 - RSI 0.78 = Add R9 for 80%	43.9	$3,156
d. R0 to R12 - RSI 0.78 = Add R9 for 60%	26.3	$2,367
e. R8 to R12 = Add R3.8 for 100%	2.8	$1,315
f. R8 to R12 = Add R 3.8 for 80%	2.24	$1,052
g. R8 to R12 = Add R3.8 for 60%	1.7	$789
Weighted Average	**23.5**	**$2,377**
BASEMENT INSULATION		
a. R0 to R23 for 100%	30	$2,255
b. R0 to R23 for 80%	24	$1,804
c. R0 to R23 for 60%	18	$1,353
d. R0 to R10 for 100%	29.1	$981
e. R0 to R10 for 80%	23.3	$785
f. R0 to R10 for 60%	17.4	$589
Weighted Average	**23.6**	**$1,310**
CRAWL SPACE INSULATION & MISC - 7%		
a. R0 to R10 - "Add R10"	5.5	$409
b. 0 to R23 - "Add R23"	6.4	$940
c. Floor above crawl space	2.2	$500
d. Header - No to R20	1.6	$250
e. Exposed Floor	2	$500
Weighted Average	**3.5**	**$535**
WINDOWS - 26%		
Estar Windows (to min zone requirements)Standard double pane USI 2.0 TO Energy Star Zone A (South), Zone B (Interior) - 15 WINDOWS	10.5	$261
Estar Windows (to one zone up)Standard double pane USI 4.0 TO Energy Star Zone B (South), Zone C (Interior) - 15 WINDOWS	16.5	$562
Weighted Average	**13.1**	**$444**

Energy Savings per Installation (GJ)	1. Measure Description: Air sealing based on 15-25% improvement over base Insulation (attic, walls, basements, and crawl space) based on incremental increase in R value Windows – upgrade to ENERGY STAR for minimum zone and one zone up requirements.
Energy Savings Determination Methodology	2. Energy savings based on Innes Hood Consulting, Habart Consulting and discussions with electric utility partners. Based on Hot 2000 modeling of select BC archetype in Lower Mainland and Interior.
Measure Lifetime (years)	• Air Sealing – 15 years (considered range of 10-15 years) • Insulation – 25 years (considered range of 20-25 years) • Windows - 20 years (considered range of 20-25 years)
Measure Lifetime Determination Methodology	Consultations with BC Hydro, consultants Habart and Hood and 2010 Conservation Potential Review.
Incremental Cost ($)	Please refer to reference table
Incremental Cost Determination Methodology	Consultations with BC Hydro and consultants Habart and Hood based on discussion with trades.
Residential Program (1.5) (High Carbon Fuel Switching)	**High Carbon Fuel Switching Switch 'N Shrink (Residential oil to natural gas conversions)**
Energy Savings per Installation (GJ)	3 GJ saved through natural gas technology upgrade – Note this program is load building of 43 GJs per installation
Energy Savings Determination Methodology	1. Measure Description: a. Baseline technology: Replace old oil furnace with new oil furnace b. Existing: 0.60 AFUE oil furnace (≥ 25 years old) c. Standard oil unit: 0.83 AFUE d. Efficient natural gas unit: ≥0.90 AFUE 2 and 3. Data sources /Engineering analysis: a. 2008 REUS study provided FEVI annual heating load of 46GJ b. 3 GJ savings associated with upgrade from 0.83 AFUE oil furnace to 0.90 AFUE natural gas based on discussions with NRCan and DOE research on furnace types. 3. Range of savings: Average FEVI heating consumption based on REUS data was best estimate. 3 GJ savings on appliance upgrade was considered to be conservative since 11 GJs was attributed in natural gas upgrade from 0.80 AFUE to 0.90 AFUE. 5. Assumptions:

	The energy consumption is based on the difference between the amount of displaced oil or propane and the amount of natural gas consumption after conversion. 6. Energy savings : a. Enbridge Gas: not applicable b. Union Gas: pending request c. BC Hydro: not applicable d. Efficiency Nova Scotia: switch from electric heating (space and domestic hot water) to natural gas or wood/pellet heating to reduce electricity load. Energy savings not clear 7. Code and Standard: not applicable to fuel switching program
Measure Lifetime (years)	18 years
Measure Lifetime Determination Methodology	1. Data Sources: a. Navigant Consulting Inc. report "*Measures and Assumptions for Demand Side Management (DSM) Planning*", p. C-41, prepared for the Ontario Power Authority in April 16, 2009. b. BC Hydro, Power Smart. *QA Standard, Technology: Effective Measure Life*, Sept. 11, 2006 c. NRCan, personal communication with Rosalyn Cochrane, Senior Standards Engineer 2. Range of measure life: 18-20 years 3. Assumptions: Based on natural gas heating system projected life. 4. Measure life time - other utilities: a. Enbridge Gas: not applicable b. Union Gas: pending request c. BC Hydro: not applicable d. Efficiency Nova Scotia: indefinite since when customers switched to gas from oil, the chance of switching back is slim
Incremental Cost ($)	$1000 (cost associated with difference in price between oil and NG furnace installation)
Incremental Cost Determination Methodology	1. Data Sources: a. Communication with contractors on Vancouver Island b. The installed cost of oil furnace: $4,000 - $4500 c. The installed cost of gas furnace conversion: $5,800 (based on average of 2010 program participant costs) 2. Range of incremental cost: $600-$1,250 3. Assumptions: a. Assumes a standard gas service installation cost (within the service line cost allowance) and does not include the price of oil tank replacement 4. Incremental costs - other utilities: a. Enbridge Gas: not applicable

	b. Union Gas: pending request c. BC Hydro: not applicable d. Efficiency Nova Scotia: the full equipment cost with no details disclosed.

Commercial Programs:

As noted in the introduction to this response, every effort has been made to answer the questions asked in the format required. It should be understood, however, that not all commercial programs are prescriptive in nature. Pilot programs are generally used to establish reasonable measure savings, lives and costs; thus the initial data is often based on the analysis of a limited number of individual participants. In a number of cases therefore the questions either do not apply or the answers cannot be summarized by a simple response suitable for presentation in the requested format.

The PSECA Initiative, for example, provided customized incentives for a broad and heterogeneous range of energy savings measures. Individual measure savings, lives and incremental costs were identified in participant provided and FortisBC reviewed energy studies. It is therefore not possible to report a single energy savings per installation, measure life or incremental cost. Moreover, reporting these metrics for other utility programs across the country is not feasible either because no comparable program exists, or if such a program does exist, it does not claim a simple value for measure savings, life or incremental cost, or in the case of BC Hydro, the program focused on electricity saving measures which cannot be directly compared to natural gas.

Table 2: Commercial Program Information

Commercial Program (2.1)	Efficient Boiler Program (Retrofit)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	510 GJ Savings: 15% of pre retrofit consumption
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: regulation required atmospheric Boiler. 80% Combustion Efficiency. c. Efficient Technology: High efficiency (Condensing or near condensing) Boiler. 85 -98% combustion efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (BTS-2000, CSA 4.9). 2 and 3. Data Sources/Engineering Analysis a. Savings: 15% of pre retrofit consumption b. Data Sources:

	a. EBP impact evaluation study, July 2003 b. Natural Resources Canada c. E-Source d. Consortium for Energy Efficiency (CEE) e. Ontario DSM Assumptions 4. Range Considered: None to date. Range not identified in previous impact evaluation. The program is undergoing impact analysis and a subsequent redesign. The range will be considered during the process of data synthesis and program redesign. 5. Assumptions: 15% reasonably represents the savings experience across all customer types. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program – Gas only b. FortisBC Electric: No applicable program – Gas only c. Enbridge: 0.0104 m^3 (0.0004 GJ) / btu/hr boiler input d. Union Gas: 0.0104 m^3 (0.0004 GJ) / btu/hr boiler input e. Manitoba Hydro: 7,927 m^3 (305 GJ) f. SaskEnergy: 10,138 m^3 (390 GJ) g. Gaz Metro: 4,617 to 6221 m^3 (187 to 239 GJ) 7. Impact Evaluation: a. FortisBC has recently completed an impact evaluation of participants in the retrofit Efficiency Boiler Program. Please refer to Attachment 118.1 provided in response to BCUC 2.118.1. b. The 2003 Impact evaluation study has not been provided in response to either BCUC 2.118.1 or 2.97.1 as it predates the EEC program approval. It is however available at the Commission's request. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	20 years
Measure Lifetime Determination Methodology	1. Data Sources a. ASHRAE Handbook, Service life Expectancy b. CEE boiler recommendations c. Terasen Gas 2006 Conservation Potential Review d. Ontario Energy Board approved DSM assumptions e. E-Source research f. Discussions with suppliers and installers 2. Range Considered: 18 to 25 yrs. 3. Assumptions: a. It is assumed that the 18 to 25 year lifetime identified in available references is an accurate reflection of the measure life. 4. Measure lifetimes - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 25 yrs

	d. Union Gas: 25 yrs e. Manitoba Hydro: 25 yrs f. SaskEnergy: Not Reported g. Gaz Metro: 18 to 25 yrs
Incremental Cost ($)	$ 35,834
Incremental Cost Determination Methodology	1. Data Sources: a. Measure cost: Invoice data collected from all program participants b. Baseline cost: Data estimated from available market research. c. Incremental cost is calculated as the difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not considered. 3. Assumptions: a. 7 $/MBH is a reasonable estimate of the cost of a baseline alternative boiler. 4. Incremental Cost - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0.012 $/ btu/hr boiler input d. Union Gas: 0.012 $/ btu/hr boiler input e. Manitoba Hydro: 4 $/MBH input near condensing, 12 $/MBH input condensing. f. SaskEnergy: Not Reported g. Gaz Metro: $ 7,578 to$ 15,756

Commercial Program (2.2)	**Efficient Boiler Program (New Construction)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	1,069 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: regulation required atmospheric Boiler. 80% Combustion Efficiency. c. Efficient Technology: High efficiency (Condensing or near condensing) Boiler. 85 -98% combustion efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (BTS-2000, CSA 4.9) 2 and 3. Data Sources/Engineering Analysis: a. Savings: are as identified by participant provided engineering analysis. 4. Range Considered: None to date. a. The program is undergoing impact analysis and a subsequent redesign. The range will be considered during

	the process of data synthesis and program redesign. 5. Assumption: Engineering calculations are reasonable accurate. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0.014 m^3 (0.000538 GJ) / btu/hr boiler input d. Union Gas: No applicable program e. Manitoba Hydro: 7,927 m^3 (305 GJ) f. SaskEnergy: Not Reported g. Gaz Metro: 4,617 to 6221 m^3 (187 to 239 GJ) 7. Impact Evaluation: a. FortisBC has yet to conduct an impact evaluation on the New Construction version of the program due to the limited number of new construction participants (5% of EBP since April 2009), and the inherent difficulty of evaluating a hypothetical comparison. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology
Measure Lifetime (years)	20 years
Measure Lifetime Determination Methodology	1. Data Sources: a. CEE boiler recommendations b. ASHRAE Handbook, Service life Expectancy c. Terasen Gas 2006 Conservation Potential Review d. Ontario Energy Board approved DSM assumptions e. E-Source research f. Discussions with suppliers and installers 2. Range Considered: 18 to 25 yrs. 3. Assumptions: a. It is assumed that the 18 to 25 year lifetime identified in available references is an accurate reflection of the measure life. 4. Measure lifetimes used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 25 yrs d. Union Gas: No applicable program e. Manitoba Hydro: 25 yrs f. SaskEnergy: Not Reported g. Gaz Metro: 18 to 25 yrs
Incremental Cost ($)	$ 65,711
Incremental Cost Determination Methodology	1. Measure is considered to be incremental, not full cost. a. Measure cost: Invoice data collected from all participants b. Baseline cost: Data estimated from available market research c. Incremental cost is calculated as the difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not

	considered. 3 .Assumptions: 7 $/MBH is a reasonable estimate of the cost of a baseline alternative boiler. 4. Incremental Cost used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: Per Ontario DSM Assumptions d. Union Gas: Not Applicable e. Manitoba Hydro: 4 $/MBH input near condensing, 12 $/MBH input condensing. f. SaskEnergy: Not Reported g. Gaz Metro: $ 7,578 to$ 15,756

Commercial Program (2.3)	Light Commercial ENERGY STAR Boiler Program (Retrofit)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	296 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: regulation required atmospheric Boiler. 80% Combustion Efficiency. c. Efficient Technology: High efficiency (Condensing or near condensing) Boiler. 85 -98% combustion efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (BTS-2000, CSA 4.9) 2 and 3. Data Sources/Engineering Analysis: 1. Savings: 15% of pre retrofit consumption 2. Data Sources: a. Natural Resources Canada b. EBP impact evaluation study, July 2003 c. E-Source d. Consortium for Energy Efficiency (CEE) e. Ontario DSM Assumptions 4. Range Considered: None to date. Range not identified in previous EBP impact evaluation. a. The range will be evaluated during the revision to the Efficient Boiler Program. 5. Assumptions: a. 15% reasonably represents the savings experience across all customer types. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0.0104 m^3 (0.0004 GJ) / btu/hr boiler input d. Union Gas: 0.0104 m^3 (0.0004 GJ) / btu/hr boiler input e. Manitoba Hydro: 7,927 m^3 (305 GJ) f. SaskEnergy: Not Reported

	g. Gaz Metro: 4,617 to 6221 m^3 (187 to 225 GJ) 7. Impact Evaluation: a. FortisBC has not yet completed an impact evaluation on this program due to its relative newness (Launched August 2009) 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology
Measure Lifetime (years)	20 years
Measure Lifetime Determination Methodology	1. Data Sources a. CEE boiler recommendations b. ASHRAE Handbook, Service life Expectancy c. Terasen Gas 2006 Conservation Potential Review d. Ontario Energy Board approved DSM assumptions e. E-Source research f. Discussions with suppliers and installers 2. Range Considered: 18 to 25 yrs a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 25 yrs d. Union Gas: 25 yrs e. Manitoba Hydro: 25 yrs f. SaskEnergy: Not Reported g. Gaz Metro: 18 to 25 yrs
Incremental Cost ($)	$ 18,695
Incremental Cost Determination Methodology	1. Data Sources: a. Measure cost: Invoice data collected from, participants, supported by data from the Efficient Boiler Program b. Baseline cost: Data estimated from available market research. c. Incremental cost: Calculated difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not considered. 3. Assumptions: a. 7 $/MBH is a reasonable estimate of the cost of a baseline alternative boiler. 4. Incremental Cost used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0.012 $/ btu/hr Boiler input d. Union Gas: 0.012 $/ btu/hr boiler input e. Manitoba Hydro: 4 $/MBH input near condensing, 12 $/MBH input condensing. f. SaskEnergy: Not Reported g. Gaz Metro: $ 7,578 to$ 10,598

Commercial Program (2.4)	Light Commercial ENERGY STAR Boiler Program (New Construction)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	111 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: regulation required atmospheric Boiler. 80% Combustion Efficiency. c. Efficient Technology: High efficiency (Condensing or near condensing) Boiler. 85 -98% combustion efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (BTS-2000, CSA 4.9) 2and3.Data Sources/Engineering Analysis: a. Savings: Based on retrofit energy savings, proportionally adjusted to suite the input rating of boilers submitted to the program as "new construction". b. Data Sources: a. Natural Resources Canada b. E-Source c. Consortium for Energy Efficiency (CEE) d. Ontario DSM Assumptions 4. Range Considered: None to date. Range not identified in previous impact evaluation. a. The range will be evaluated during the revision to the Efficient Boiler Program. 5. Assumptions: c. Based on retrofit energy savings, proportionally adjusted to suite the input rating of boilers submitted to the program as "new construction". 6. Annual energy savings - other utilities: e. BC Hydro: No applicable program f. FortisBC Electric: No applicable program a. Enbridge: 0.014 m^3 (0.000538 GJ) / btu/hr boiler input b. Union Gas: Not Applicable c. Manitoba Hydro: 7,927 m^3 (305 GJ) d. SaskEnergy: Not Reported e. Gaz Metro: 4,617 to 6221 m^3 (187 to 225 GJ) 7. Impact Evaluations: a. FortisBC has not yet completed an impact evaluation on this program due to its relative newness (Launched August 2009) 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology
Measure Lifetime (years)	20 years
Measure Lifetime Determination Methodology	1. Data Sources a. CEE boiler recommendations b. ASHRAE Handbook, Service life Expectancy

	c. Terasen Gas 2006 Conservation Potential Review d. Ontario Energy Board approved DSM assumptions e. E-Source research f. Discussions with suppliers and installers 2. Range Considered: 18 to 25 yrs. 3. Measure lifetimes - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 25 yrs d. Union Gas: No applicable program e. Manitoba Hydro: 25 yrs f. SaskEnergy: Not Reported g. Gaz Metro: 18 to 25 yrs
Incremental Cost ($)	$2,047
Incremental Cost Determination Methodology	1. Data Sources: a. Measure cost: Invoice data collected from program participants, supported by data from the Efficient Boiler Program b. Baseline cost: Data estimated from available market research. c. Incremental cost: Calculated difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not considered. 3. Assumptions: 7 $/MBH is a reasonable estimate of the cost of a baseline alternative boiler. 4. Incremental Cost - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0.012 $/ btu/hr Boiler input d. Union Gas: No applicable program e. Manitoba Hydro: 4 $/MBH input near condensing, 12 $/MBH input condensing. f. SaskEnergy: Not Reported g. Gaz Metro: $ 7,578 to$ 10,598

Commercial Program (2.5)	Efficient Commercial Water Heater Program (Retrofit)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	89 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: Standard commercial grade water heaters (Storage, Boiler, Tankless) - Generally 80% Thermal

	Efficiency. c. Efficient Technology: High efficiency water heater (Storage, Boiler, Tankless) - 84 -99% Thermal Efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (AHRI, ANSI, CSA) 2 and 3. Data Sources/Engineering Analyses: a. Savings: established as the difference between the baseline consumption and the efficiency adjusted (ratio analysis) consumption. Baseline consumption taken as the lesser of: a) Gas consumption per DHW "Driver" (Meals/day, suites, patients) b) Gas consumption based on sector specific Energy Use Intensity c) Total annual gas consumption b. Data Sources: a) California Public Utilities Commission Database for Energy-Efficient Resources b) Ontario DSM Assumptions c) Consortium for Energy Efficiency (CEE). 4. Range Considered: a. The Companies have recently begun metering of installations within key target markets (restaurants, MURBs, Hotels). The results of the metering may provoke the consideration of different savings estimates. 5. Assumptions: a. End Use Intensity data from the CPR approximates baseline natural gas consumption in applicable building types. b. Where consumption "driver" data can be found or extrapolated for a given participant subsector such data adequately approximates natural gas consumption across all customers within that sub sector. c. Where no seasonal variation in natural gas consumption occurs the consumption is primarily derived from water heating and may serve as a baseline. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: 1,553 m^3 (60 GJ) e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: 4,617 to 6,567 m^3 (178 to 253 GJ) 7. Impact Evaluations: a. FortisBC is currently engaged in metering of high efficiency water heater installations in key customer segments in order to refine the savings assumptions. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	12 years

Measure Lifetime Determination Methodology	1. Data Sources: a. Terasen Gas 2006 Conservation Potential Review b. Ontario Energy Board approved DSM assumptions c. Discussions with suppliers and installers 2. Range Considered: 12 to 20 yrs. a. Boilers may last 20 years, however high efficiency water heaters are relatively new; therefore FEU has decided to take a conservative approach. 3. Measure lifetimes used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: 13 years e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: 20 yrs
Incremental Cost ($)	$ 5,378
Incremental Cost Determination Methodology	1. Data Sources: a. Measure cost: Invoice data collected from program participants b. Baseline cost: Data estimated from available market research. c. Incremental cost calculated difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not considered. 3. Assumptions: baseline alternative costs: a. Boiler: 7 $ / MBH input b. Tankless: 5 $/MBH input c. Storage: 25 $ / MBH input. 4. Incremental Cost - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: $2,230 e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: $7,578 to $15,756

Commercial Program (2.6)	**Efficient Commercial Water Heater Program (New Construction)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	89 GJ.
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental.

	b. Baseline technology: Standard commercial grade water heaters (Storage, Boiler, Tankless) - Generally 80% Thermal Efficiency. c. Efficient Technology: High efficiency water heater (Storage, Boiler, Tankless) - 84 -99% Thermal Efficiency. d. Efficiencies identified per independent rating agencies, based on standardized testing (AHRI, ANSI, CSA) 2 and 3. Data Sources/Engineering Analysis: Saving established as the difference between the baseline consumption and the efficiency adjusted (ratio analysis) consumption. Baseline consumption taken as the lesser of: a. Gas consumption per DHW "Driver" (Meals/day, suites, patients) b. Gas consumption based on sector specific Energy Use Intensity c. California Public Utilities Commission Database for Energy-Efficient Resources d. Ontario DSM Assumptions e. Consortium for Energy Efficiency (CEE). 4. Range Considered: a. The Companies have recently begun metering of installations within key target markets (restaurants, MURBs, Hotels). The results of the metering may provoke the consideration of different savings estimates. 5. Assumptions: a. It is assumed that savings in the new construction market are the same as those for retrofit market participants. This may be revised as additional data becomes available. Currently there are only 4 new construction participants in the program. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: 1,553 m^3 (60 GJ) e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: 4,617 to 6,567 m^3 (178 to 253 GJ) 7. Impact Evaluations: a. FortisBC is currently engaged in metering of high efficiency water heater installations in key customer segments in order to refine the savings assumptions. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	12 years
Measure Lifetime Determination Methodology	1. Data Sources: a. Terasen Gas 2006 Conservation Potential Review b. Ontario Energy Board approved DSM assumptions c. Discussions with suppliers and installers 2. Range Considered: 12 to 20 yrs.

	a. Boilers may last 20 years, however high efficiency water heaters are relatively new, thus FEU has decided to take a conservative approach. 3. Assumptions: inapplicable 4. Measure lifetimes - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: 13 yrs e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: 20 yrs
Incremental Cost ($)	$ 5,378
Incremental Cost Determination Methodology	1. Data Sources: a. Measure cost: Invoice data collected from program participants b. Baseline cost: Data estimated from available market research. c. Incremental cost: Calculated as the difference between the measure cost and the baseline cost. 2. Range Considered: a. Incremental cost is established as the average of all program participants in a given year. A range is not considered. 3. Assumptions: New Construction market participants have the same measure cost as retrofit market participants. baseline alternative costs: a. Boiler: 7 $/MBH input b. Tankless: 5 $/MBH input c. Storage: 25 $/MBH input 4. Incremental Cost used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: No applicable program d. Union Gas: $2,230 e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: $7,578 to $15,756

Commercial Program (2.7)	**Energy Assessment Program (Retrofit)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	488 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Full cost. b. Baseline technology: Not Applicable

	c. Efficient Technology: Not Applicable d. Efficiencies: Not Applicable e. Data Sources: Not Applicable 2 and 3. Data Sources/Engineering analysis: a. Data Sources: Based on savings identified in two separate impact evaluations b. Savings: Deemed savings: 488 GJ / participant 4. Range Considered: a. 299 GJ/yr to 677 GJ/yr per participant. Average values identified in two (2) distinct program impact evaluations. 5. Assumptions: As identified in the impact evaluations. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: 0 GJ/yr d. Union Gas: 0 GJ/yr e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: No applicable program 7. Impact Evaluations: a. FortisBC completed impact evaluations of the Energy Assessment Program in 2008 and 2010. Please refer to Attachment 212.1 provided in response to BCUC 1.212.1. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	1 year
Measure Lifetime Determination Methodology	1. Data Sources a. Not Applicable 2. Range Considered: None. a. It may be argued that a longer measure life is appropriate for the measure life of the savings attributable to participation in the Energy Assessment Program however the Companies have opted for a very conservative approach. This is due to the inherently diverse nature of the recommendations made, as well as the variable rate of implementation. 3. Assumptions: a. It is assumed that savings will not persist for more than 1 year. 4. Measure lifetimes - other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: Not applicable d. Union Gas: Not applicable. e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: No applicable program
Incremental Cost ($)	$1,200
Incremental Cost Determination Methodology	1. Data Sources: a. Actual cost of a typical Energy Assessment.

	2. Range Considered: Not Applicable 3. Assumptions: Not Applicable 4. Incremental Cost used by other utilities: a. BC Hydro: No applicable program b. FortisBC Electric: No applicable program c. Enbridge: Not applicable d. Union Gas: Not applicable. e. Manitoba Hydro: No applicable program f. SaskEnergy: No applicable program g. Gaz Metro: No applicable program

Commercial Program (2.8)	PSECA Initiative Program (Retrofit)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	Variable : Dependent upon participant proposed Energy Saving Measures
Energy Savings Determination Methodology	1. Measure Description: a. Type: Variable - Incremental or Full Cost – Dependent upon proposed project/measure. b. Baseline technology: Variable – as required by regulation for 'end of life' replacements; existing system for "early retirement" upgrades. c. Efficient Technology: Variable – As proposed by program participant and reviewed/verified by FortisBC. d. Efficiencies: Variable – As proposed by program participant, and reviewed/accepted by FortisBC. 2 and 3. Data Sources/Engineering analysis a. Energy Savings: Variable - Dependent upon program participant's project/facility. As identified in participant provided energy studies, subsequently validated by FortisBC. b. Data Sources: Participant provided energy studies, as verified by FortisBC. 4. Range Considered: Variable. – project and measure specific. 5. Assumptions: Varied. a. Each measure proposed and examined had its own set of assumptions. 6. Annual energy savings - other utilities: No applicable programs. Program is specific to the BC public sector. The FEU's incentives target gas saving measures. 7. Impact Evaluations: None available to date. a. Though closed to new participation this program is still on-going while participants complete the installation of the approved energy saving measures. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	Variable: Dependent upon participant proposed Energy Saving Measures
Measure Lifetime Determination Methodology	1. Data Sources: a. Engineer's recommendations b. CEE recommendations/guidelines c. ASHRAE Handbook, Service life Expectancy d. Ontario Energy Board approved DSM assumptions e. E-Source research 2. Range Considered: Variable. Measures lifetimes were associated with project specific measures. 3. Assumptions: Variable. 2. Dependent upon project specific proposed energy saving

	measures. 4. Measure lifetimes used by other utilities: No applicable programs. Program is specific to the BC public sector. The FEU's incentives target gas saving measures.
Incremental Cost ($)	Variable : Dependent upon participant proposed Energy Saving Measures
Incremental Cost Determination Methodology	1. Data Sources: a. Participant supplied Energy Study b. All data sources available via the Companies other program offerings c. Consultant recommendations 2. Range Considered: a. Variable – Dependent upon project specific proposed energy saving measures. 3. Assumptions: Variable. a. Dependent upon proposed energy saving measures. 4. Incremental Cost used by other utilities: No applicable programs. Program is specific to the BC public sector. The FEU's incentives target gas saving measures.

Commercial Program (2.9)	Fireplace Timers Pilot Program (Retrofit)
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	3 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Full Cost. b. Baseline technology: On/Off switch c. Efficient Technology: Timer switch allowing the selection of 30 minutes, 60 minutes and 120 minutes of fireplace operation. d. Efficiencies: Not applicable 2 and 3. Data Sources/Engineering Analysis: e. Savings: deemed 3 GJ per installed timer. f. Data Sources: Studies of timers installed in two separate Stratas, in the lower mainland. 4. Range Considered: 3 GJ/yr to 6 GJ/yr per timer installed. 5. Assumptions: a. the savings are assumed to be reasonable pending completion of the pilot study. 6. Annual energy savings - other utilities: No applicable programs 7. Impact Evaluations: a. The aim of the pilot program is to perform an impact evaluation once a sufficient number of timers have been installed. Expected completion: June 2012. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.

Measure Lifetime (years)	5 years
Measure Lifetime Determination Methodology	1. Data Sources a. Discussion with timer manufacturer 2. Range Considered: None. 3. Assumptions: 5 year measure life. a. The technology (electronic as opposed to mechanical) is relatively uncommon in fireplace timer switches. The Companies believe a 5 year measure life to be reasonable. Over the longer term the installations in the pilot study will help establish a reliable measure life. 4. Measure lifetimes used by other utilities: No applicable programs
Incremental Cost ($)	$50
Incremental Cost Determination Methodology	1. Data Sources: a. Manufacturer provided timer cost 2. Range Considered: None considered. a. The cost is based on actual timer cost plus an allowance for installation 3. Assumptions: a. It is assumed that a timer may be installed for approximately $30, when installations are performed on a building wide scale. 4. Incremental Cost used by other utilities: No applicable programs

Commercial Program (2.10)	**Radiant Tube Heaters Pilot Program (Retrofit)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	275 GJ (Initial test site)
Energy Savings Determination Methodology	1. Measure Description: a. Type: Incremental. b. Baseline technology: Standard commercial grade unit heaters – generally 80% combustion efficiency c. Efficient Technology: Radiant tube heaters – Generally 80% combustion efficiency d. Source of savings: Radiant as opposed to convective heating is believed to be more efficient at providing occupant comfort in large open spaces. Radiant tube heaters heat objects directly instead of large volumes of air, as with a unit heater. 2and3.Data Sources/Engineering Analysis: a. Savings: Variable. Evaluated on a site by site basis for the purpose of the pilot study. Retrscreen or other similar engineering software used to asses savings. b. Data Sources: Other utility programs were reviewed for an initial estimate of potential savings. However the purpose of the pilot program is to evaluate the savings potential in British Columbia.

	4. Range Considered: None. Savings are site specific in the pilot stage 5. Assumptions: 20% improvement in seasonal efficiency. 6. Annual energy savings - other utilities: a. BC Hydro: No applicable programs b. FortisBC Electric: No applicable program c. Enbridge: 0.015 m^3 (0.00058 GJ) / btu/hr d. Union Gas: 0.015 m^3 (0.00058 GJ) / btu/hr e. Manitoba Hydro: No applicable programs f. SaskEnergy: No applicable programs g. Gaz Metro: 1,329 m^3 (51 GJ) 7. Impact Evaluations: a. The aim of the pilot program is to perform an impact evaluation after radiant heaters have been installed in several locations throughout the province. The impact evaluation will help determine if radiant tube heaters are a cost effective measure in the various climate zones in British Columbia. Expected Completion: 2013 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	20 years
Measure Lifetime Determination Methodology	1. Data Sources a. Ontario Energy Board approved DSM assumptions b. Discussions with suppliers and installers 2. Range Considered: a. Measure life was not evaluated in detail for the pilot study. The objective of the study is to validate savings claims in the climate zones of BC. Should savings prove in line with expectations, measure life will be evaluated in greater detail during the program development. 3. Assumption: a. The measure lives indicated by the available sources is reasonably accurate. 4. Measure lifetimes used by other utilities: a. BC Hydro: No applicable programs b. FortisBC Electric: No applicable programs c. Enbridge: 20 d. Union Gas: 20 e. Manitoba Hydro: No applicable programs f. SaskEnergy: No applicable programs g. Gaz Metro: 15 yrs
Incremental Cost ($)	$4,368 (Initial test site)
Incremental Cost Determination Methodology	1. Data Sources: a. Actual quotes for a unit heater based heating system vs. a radiant tube heater based system at test site #1. b. Standard (Unit Heater) system: $10,080 c. High Efficiency (radiant tube) system: $14,448 2. Range Considered: None considered. a. The incremental cost will be based on actual quoted costs at

	each test site. 3. Assumptions: The provided quotations are fair and reasonable. 4. Incremental Cost used by other utilities: a. BC Hydro: No applicable programs b. FortisBC Electric: No applicable program c. Enbridge: 0.0122 $/btu/hr input d. Union Gas: 0.0122 $/btu/hr input e. Manitoba Hydro: Not Applicable f. SaskEnergy: No applicable programs g. Gaz Metro: $813

Commercial Program (2.11)	**Spray Valve Program (Retrofit)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	9 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Full Cost. b. Baseline technology: restaurant’s existing spray valve – flow rate as measured on site. c. Efficient Technology: Low flow spray valve – 1.6 GPM. d. Data sources: a. Food Service Technology Center Test Summary. b. Previous Program Data collection 2and3.Data Sources/Engineering Analysis a. Savings: Deemed savings of 9 GJ/valve-yr b. Data Sources: Previous program data collection and analysis. 4. Range Considered: 8 GJ/yr to 15 GJ/yr per valve. 5. Assumptions: a. Customer reported “time of use” data is roughly representative of reality in the aggregate. b. Spray valve water flow is on average composed of 50% hot / 50% cold 6. Annual energy savings - other utilities: a. BC Hydro: 10,590 kwh (38.12 GJ) / valve b. FortisBC Electric: 9,323 kwh (33.56 GJ) / valve c. Enbridge: 190 to 886 m^3 (7.3 to 34 GJ) / valve d. Union Gas: 190 to 886 m^3 (7.3 to 34 GJ) / valve e. Manitoba Hydro: 1304 m^3 (50 GJ) f. SaskEnergy: No applicable programs g. Gaz Metro: No applicable programs 7. Impact Evaluation: None completed to date. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology.
Measure Lifetime (years)	5 years
Measure Lifetime Determination	1. Data Sources:

Methodology	a. Food Service Technology Center b. Ontario Energy Board approved DSM assumptions 2. Range Considered: None. 3. Assumptions: a. A 5 year measure life reasonably represents the useful life of a pre rinse spray valve. 4. Measure lifetimes used by other utilities: a. BC Hydro: 5 yrs b. FortisBC Electric: Not available c. Enbridge: 5 yrs d. Union Gas: 5 yrs e. Manitoba Hydro: 10 yrs f. SaskEnergy: No applicable programs g. Gaz Metro: No applicable programs
Incremental Cost ($)	$130
Incremental Cost Determination Methodology	1. Data Sources: a. Actual cost of spray valve and labour costs from previous versions of the spray valve program. 2. Range Considered: None considered. a. Incremental cost based on previous program history. 3. Assumptions: a. The valves may be installed for approximately $65 per valve. 4. Incremental Cost used by other utilities: a. BC Hydro: $125 b. FortisBC Electric: Not Available c. Enbridge: $65 / valve d. Union Gas: $60 / valve e. Manitoba Hydro: $106.71 f. SaskEnergy: No applicable programs g. Gaz Metro: No applicable programs

Commercial Program (2.12)	**Spray Valve Program (New Construction)**
Energy Savings per Installation (Average Annual Energy Savings per Measure) (GJ)	9 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Type: Full Cost. b. Baseline technology: restaurant's existing spray valve – flow rate as measured on site. c. Efficient Technology: Low flow spray valve – 1.6 GPM. d. Data sources: i. Food Service Technology Center Test Summary. ii. Previous Program Data collection 2 and 3. Data Sources/Engineering analysis: a. Savings: Deemed savings of 9 GJ/valve-yr. b. Data Sources: Previous program data collection and

	analysis. 4. Range Considered: 8 GJ/yr to 15 GJ/yr per valve. 5. Assumptions: a. "Time of use" is identical to retrofit applications. b. Spray valve water flow is on average composed of 50% hot / 50% cold 6. Annual energy savings - other utilities: a. BC Hydro: 10,590 kwh (38.12 GJ) / valve b. FortisBC Electric: Not Available c. Enbridge: 190 to 886 m^3 (7.3 to 34 GJ) / valve - year d. Union Gas: Not Applicable e. Manitoba Hydro: 1304 m^3 (50 GJ) f. SaskEnergy: No applicable programs g. Gaz Metro: No applicable programs 7. Impact Evaluation: None completed to date. 8. Codes or Standards: There is no applicable code or standard that requires participants to upgrade to the efficient technology
Measure Lifetime (years)	5 years
Measure Lifetime Determination Methodology	1. Data Sources: a. Food Service Technology Center b. Ontario Energy Board approved DSM assumptions c. City of Vancouver study. 2. Range Considered: a. The relatively close alignment of measure lives among all sources precluded the consideration of different measure lifetimes. 3. Assumptions: a. A 5 year measure life reasonably represents the useful life of a pre rinse spray valve. 4. Measure lifetimes used by other utilities: a. BC Hydro: 5 yrs b. FortisBC Electric: Not Available c. Enbridge: 5 yrs d. Union Gas: No applicable programs e. Manitoba Hydro: 10 yrs f. SaskEnergy: No applicable programs g. Gaz Metro: No applicable programs
Incremental Cost ($)	$130
Incremental Cost Determination Methodology	1. Data Sources: a. Actual cost of spray valve and labour costs from previous versions of the spray valve program. 2. Range Considered: None considered. a. Incremental cost based on previous program history. 2. Assumptions: The valves may be installed for approximately $65 per valve. 3. Incremental Cost used by other utilities: a. BC Hydro: $125 b. FortisBC Electric: Not Available c. Enbridge: $60 / valve

	d. Union Gas: Not Applicable e. Manitoba Hydro: $106.71 f. SaskEnergy: Not Applicable g. Gaz Metro: Not Applicable

3. Industrial Programs:

FEU's initial Energy Efficiency and Conservation (EEC) Programs application indicated that an industrial Demand Side Management Program (DSM) would need to recognize the uniqueness of individual sites. The industrial Conservation Potential Review (CPR) confirmed this analysis. As such, FEU's Industrial Programs involve a high degree of customization.

Many industrial processes require "heat" to process materials into their final form. Examples include the conversion of wood into pulp and paper, and gas, oil and coal into plastics and pharmaceuticals. In each of these processes, different forms of heat and different temperatures may be required, such as high-temperature combustion gases, high- and low-pressure steam, and hot or warm water. Data for these unique processes is often not readily available in the format and detail requested by the Commission.

Table 3: Industrial Program Information

Industrial Program (3.1)	**Heat Exchanger Program (Pilot)**
Energy Savings per Installation (GJ)	70,000 GJ/yr.
Energy Savings Determination Methodology	1. Measure Description: Replacement of three large shell and tube design waste water heat exchangers used to extract heat from a waste water stream to heat incoming fresh water for a pulp process. a. Baseline Technology: Existing heat exchangers – 1981 and 1990 model. Efficiency data unavailable. b. Efficient Technology: Alfa Laval heat exchangers – The efficiency upgrade will be dependent on the temperature of the fluid that is circulated through the new condensing heat exchanger. 2. Engineering analysis: Please see attached engineering analysis. Savings: Deemed 70,000 GJ/yr the estimated value from the most

	recent mill wide pinch study (2009) 3.Data Sources: See attachments and reports provided by Pragmatic Inc. and Fransen Eng. a. "Effluent Energy Recovery and Dryers Gas Saving Project, review of the Mill's Project Concept of May 20, 2010" simulation study prepared by Pragmatic Inc. b. Spreadsheet prepared by Fransen Eng. 4. Range of savings: unavailable. 5. Assumptions: a. Two fluid streams from the process may be captured and the associated heat fully utilized. b. The temperature of the discharge waste water leaving the heat exchangers can be improved by about 15°C. c. Efficiency is dependent on the temperature rise of the discharge waste water. 6. Energy Savings – other utilities: unavailable 7. Impact Evaluations: None completed to date 8. Code and Standards: not applicable
Measure Lifetime (years)	10 years
Measure Lifetime Determination Methodology	1. Data sources: a. Manufacturer: Model 1H – L – 2T has 20 to 30 years measure life. b. E-source: The typical lifespan of industrial heat exchangers is 15 years. 2. Range of measure life: a. The customer data: 25 to 30 years. b. As this is a pilot program FEU went with the conservative measure life range and used 10 years. 3. Impact Evaluation: Not applicable – program too new/ in pilot stage 4. Code and Standard: Not applicable - no energy efficiency standard for this equipment
Incremental Cost ($)	$2,000,000 CDN (+, - 20%), according to the study done by Pragmatic Inc. on behalf of West Fraser.
Incremental Cost Determination Methodology	1. Data sources: a. The incremental cost for the project was provided as part of the program application process which consisted on the proposed price of the purchase, installation and commissioning of the system. "Effluent Energy Recovery and Dryers Gas Saving Project review of the Mill's Project Concept of May 20, 2010" simulation study prepared by

	Pragmathic Inc. b. Based on the final estimate spreadsheet that was created by Fransen Engineering on behalf of West Fraser. 2. Range of incremental cost: a. From $1,600,000 to $2,400,000 CDN. (The data and the sources of data reviewed to determine the incremental cost is attached to this sheet). 3. Assumptions: see 1 a. and b. 4. Other utilities: Not applicable – customized program

Industrial Program 3.2	**Burner Management Control**
Energy Savings per Installation (GJ)	1,296 GJ/yr.
Energy Savings Determination Methodology	1. Measure Description: The Micro Modulation system provides an easily programmable and flexible means of optimizing combustion quality throughout the load requirement range of the boiler/burner. The MM system displays the positioning data for up to six individually controlled channels. a. The program offers incentives to replace the existing burner management system with a new Auto Flame Mini Mk7 Micro Modulation Control Unit. b. Baseline technology: Mechanical systems that have involved linkages to characterize the fuel**:** air ratio. The existing burner control system is managed by a steam pressure controller which controls a motor to drive the gas valve and the air damper by mechanical linkages. Efficiency 81.5% c. Efficient technology: The mechanical set of control will be replaced by an automatic burner control system called "Mini Mk7 Micro Modulation Control Unit". Efficiency 84.5%. 2 and 3. Data sources/Engineering Analyses: Please see attached combustion emissions report and follow the link below http://www.autoflame.com/item.asp?pge=inter-continental 4. Savings: Deemed 1296 GJ/yr 5. Assumptions: 3% increase in efficiency. 6. Other utilities: Not applicable – customized program 7. Impact Evaluations: None completed to date. 8. Code and Standard: not applicable

Measure Lifetime (years)	10 years
Measure Lifetime Determination Methodology	1. Data source: a. Manufacturer: Typical lifespan for this equipment is solely dependent on the customers care and maintenance of the unit. The data provided by the customer and the manufacturer the life span for the new burner management system is not less than 10 years. b. E-source: 10 years is a reasonable measure life for this type control. 2. Range of measure life: not applicable. 3. Impact Evaluation: Not applicable – program too new. 4. Code and Standard: Not applicable - There is no applicable code or standard that requires participant to upgrade to the efficient technology
Incremental Cost ($)	$14,000 CDN (+, - 15%)
Incremental Cost Determination Methodology	1. Data source: Consultation with customer and the manufacturer. 2. Range of incremental cost: $13,000 – $16,000 3. Assumption: Not applicable – based on vendor quote 4. Other utilities: Not applicable – customized program

4. Affordable Housing Program:

The Energy Saving Kit (ESK) program is a unique relative to most other DSM program areas in that the ESK's are available to low income participants free of cost. And although many utilities in North America have an ESK program, FEU's program is unique in that no other utility in Canada (or perhaps even North America) has collaborated with another utility on the ESK. Almost everywhere the program is offered, it is a stand-alone kit that the utility offers to only their gas OR electric customers. For this reason, it is not easy or appropriate to compare ESK energy savings to other utility offerings. However, some research is available on the individual measures within the ESK much of that information is presented below.

Table 4: Affordable Housing Program Information

Affordable Housing (4.1):	**Energy Saving Kit**
Energy Savings per Installation (GJ)	0.9 GJ
Energy Savings Determination	1. Measure Description:

Methodology	a. Baseline technology: For many of the measures in the ESK, such as pipe insulation, plug gaskets, and window film, the underlying assumption is that there is no baseline technology present in the average participant's home. For other measures such as low flow shower heads and faucet aerators, we relied on third party study's estimates of energy savings over attempting to quantify baseline technologies for each of the measures. b. The ESK consists of a package of self-installed, gas and electric, energy savings measures. These gas measures include the faucet aerators, low flow shower head, water heater pipe wrap, window caulking, foam tape draft-proofing for doors, outlet gaskets and window film. c. Standard unit: see a. above. d. Efficiency unit: see Q4. 2 and 3. Data Sources/Engineering Analysis: a. DSM Input Assumptions from Enbridge & Union November (2008). b. Navigant Consulting Report for Ontario Energy Board February (2009) c. DSM Input Assumptions from Questar Gas Company December (2006). d. "Estimating the Energy Savings Potential Available from California's Low Income Population" Gaffney, K. and Coito, F. (2007 Energy Program Evaluation) e. "Impact of Flipping the Switch: Evaluating the Effectiveness of Low-Income Residential Energy Education Programs", Drakos, J., Khawaja, S., West, A. (2007) f. BC Hydro savings estimates for electric customers. 4.Range of savings: a. Faucet Aerators: 0.46 GJ (Questar Gas) to 1.44GJ (Navigant) b. Low Flow Showerhead: 0.9 GJ (Enbridge & Union) to 6 GJ (Questar) c. Water Heater Pipe Wrap: 0.96GJ (Navigant) to 1.47GJ (Questar) d. Window Caulking: 0.2GJ (Gaffney & Coito) e. Foam Tape: 0.2 GJ (Gaffney & Coito) f. Outlet Gaskets: .01 GJ (Drakos, Khawaja, and West) g. Window Film: 0.2GJ (very little third party research available) 5. Assumptions:

	The program total savings was estimated by adding the savings of each individual gas measure and discounting those savings by the estimated installation rates. The installation rates and free rider rates reported in the 2010 EEC report were based on BC Hydro's evaluation (participant survey) of their Energy Savings Kits. The installation rates for each measure varied between 36% and 65%. In the upcoming 2011 EEC Report, savings claims will be revised based on 2011 comprehensive Conservation Potential Review which provided a solid foundation for providing revised estimates. 6. Energy Savings - other utilities: BC Hydro's reported savings per ESK is 229 kWh in electricity savings. Note that the ESK contains some items that save electricity only (e.g. compact fluorescent lightbulbs) so the savings that BC Hydro reports is not comparable to the gas savings FEU associates with the ESK program. 7. Impact Evaluations: This program was designed as a broad reaching program that achieves small savings amongst a large number of participants. As such, the energy savings associated with this program are estimated to be too low to yield reliable results in a billing analysis. FEU will continue to rely on engineering estimates, third party studies and participant surveys to evaluate this program. 8. Code and Standards: Codes and standards do not apply to most of the measures in the ESK.
Measure Lifetime (years)	8 years
Measure Lifetime Determination Methodology	1. Data Sources: a. FEU consulted third party studies as listed below. Since BC Hydro estimates of lifetime were aligned to other studies, for consistency FEU used the same measure lifetimes that BC Hydro uses. 2. Range of measure life: a. Faucet Aerators: 10yrs (Questar Gas, Navigant, Enbridge & Union) b. Low Flow Showerhead: 10yrs (Questar Gas, Navigant, Enbridge & Union) c. Water Heater Pipe Wrap: 10yrs (Navigant, Questar) d. Window Caulking: 6yrs (BC Hydro) e. Foam Tape: 6yrs (BC Hydro) f. Outlet Gaskets: 15yrs (BC Hydro) g. Window Film: 1yr (BC Hydro)

	3. Assumptions: The measure lifetime of the ESK was determined by considering the measure lifetime of each of the gas measures in the ESK and taking an average. 4. Measure life - other utilities: see above.
Incremental Cost ($)	The ESK is provided to successful low-income applicants free of cost to the participant. Therefore, incremental costs were not considered because the incentive cost is the entire cost of the ESK. Due to the fact that the ESK program was already in market as a BC Hydro program prior to our Joint ESK collaboration, the costs of the ESK measures were all known costs. As at December 31, 2010, the incentive FEU contributed to each ESK was $9.35. This amount is a proportional cost of the gas measures (including the box and all its contents) that is equal to the proportion of participants in the joint service territory of FEU and BC Hydro that state that they use gas for heating space or water.
Incremental Cost Determination Methodology	Not applicable for reasons stated above under "Incremental Cost".

5. Innovative Technologies:

The FEU gathers assumptions throughout the program planning stage. Program planning includes gathering data through informal discussions with consultants and/or other industry experts, reviewing and/or commencing studies, investigating other programs offered by utilities and jurisdictions and the performing the Companies own analysis. As Innovative Technologies are best described as market ready technologies that have little or no market penetration in BC, there is a lack of measure specific regional industry and performance data as well as a lack of existing utility programs to review. In light of this, FEU plans to undertake pilots, conduct studies and speak with industry experts with the purpose of gathering those required inputs and update our assumptions when new information becomes available.

Table 5: Innovative Technology Program Information

Innovative Technology (5.1)	**PSECA Solar Air Program**
Energy Savings per Installation (GJ)	Varies based on each project
Energy Savings Determination Methodology	1. Measure Descriptions: a. Baseline: Solar Air is a technology uses solar energy to preheat outdoor air use for ventilation. Commercial

	customers install solar air in conjunction with their existing HVAC system to preheat air to save energy usage. Energy savings vary from project to project as does the building size/type. b. The efficiency level of the solar air: unknown. 2 and 3. Data Sources/Engineering Analysis: a. RETSCREEN (http://www.retscreen.net/ang/home.php) results conducted by a qualified professional or energy consultant reviewed and approved by NRCAN b. http://www.env.gov.bc.ca/cas/mitigation/pseca_app.html 4. Range of savings: a. 120 – 269 GJs saved per year between the 6 approved Solar Air projects 5. Assumptions: see #2 and 3 6. Energy Savings - other utilities: Not applicable 7. Impact Evaluation: Post consumption analysis, customer acceptance and installation costing will be available once all the systems have been installed. FEU is expecting impact results in late 2013 as referred to in response BCUC IR2.114.2 8. Code and Standard: not applicable
Measure Lifetime (years)	25 years
Measure Lifetime Determination Methodology	1. Data Sources: RETSCREEN Inputs developed by Natural Resources Canada 2. Range of measure life: 25 – 30 years 3. Assumptions: As this technology is relatively new and the measure life hasn't been quantified, FEU went with the conservative measure life range. 4. Other utilities: not applicable
Incremental Cost ($)	Varies based on each project
Incremental Cost Determination Methodology	1.Data Sources: a. The incremental costs for each project were provided as part of the program application process. The incremental cost includes the price of the purchase, installation and commissioning of the system. 2. Range of incremental cost: From $40,000 to $120,000 for the 6 projects. The variance is due to the uniqueness of each project being a different building size/type/application. 3. Assumptions: not applicable.

	4. Other utilities: not applicable

Innovative Technology (5.2):	**SolarBC Schools Incentive program**
Energy Savings Determination Methodology	1.Measure Descriptions: a. Baseline Technology: Baseline technology is existing boiler which is not being replaced. b. Solar Thermal Hot water is an incremental installation in conjunction with the existing boiler system to preheat water using solar energy. c. The efficiency level of the solar thermal hot water: the energy savings vary from project to project as does the building size/type. 2 and 3. Data Sources: a. RETSCREEN(http://www.retscreen.net/ang/home.php) results via a qualified professional or energy consultant reviewed and approved by NRCAN b. http://www.env.gov.bc.ca/cas/mitigation/pseca_app.html 4. Range of savings: 13 – 74 GJs saved per year between the 8 approved Solar Thermal Hot Water projects 5. Assumptions: not applicable 6. Other utilities: not applicable 7. Impact Evaluation: Post consumption analysis, customer acceptance and installation costing will be available once all the systems have been installed. FEU is expecting impact results in late 2013 as referred to in response BCUC IR 2.114.2 8. Code and Standard: not applicable.
Measure Lifetime (years)	25 years
Measure Lifetime Determination Methodology	1.Data Sources: a. Retscreen has a default measure life listed for Solar thermal http://www.retscreen.net/ang/case_studies_heating_solar_water_heater_house_canada.php 2. Range of Measure life: 20-40 years a. US Department of energy assumes a 30 year period b. Florida Solar energy center assumes a 30 year period b. Ontario Energy Board assumes a 18 year period c. Solar BC states that "domestic solar hot water systems are designed to last 20 to 40 years" (http://www.solarbc.ca/learn)

	3. Assumptions: As this technology has a low adoption curve in BC and is lacking the in depth level of monitoring required to quantify a measure life, FEU reviewed industry sources and other programs to assume a 25 year life. 4. Other utilities: not applicable.
Incremental Cost ($)	Varies based on each project
Incremental Cost Determination Methodology	1. Data Sources: The incremental costs for each project were provided as part of the program application process. It includes the price of the measure, installation and commissioning of the system. 2. Range of incremental cost: From $14,000 to $39,000 for the 8 projects. The variance is due to the uniqueness of each project being a different building size/type/application. 3. Assumptions: unavailable 4. Other utilities: Not applicable

Innovative Technology (5.3)	**Solar Residential Hot Water Pilot**
Energy Savings per Installation (GJ)	14 GJ
Energy Savings Determination Methodology	1.Measure Description: a. Baseline Technology: Baseline technology is existing hot water tank which is not being replaced. b. Solar Thermal Hot water is installed incrementally in conjunction with the existing residential hot water heater system to preheat water using solar energy. 2 and 3. Data Sources: not applicable As Solar Thermal Hot water is a technology that has minimal adoption in BC, there is a lack of quantified industry data associated with energy savings. The savings was estimated by consulting with internal expertise and industry experts such as SolarBC and installers. 4.Range of savings: 8 – 14GJ 5. Assumptions: 14GJ as the estimated energy savings for simulation purposes. 6. Other utilities: not applicable 7. Impact evaluation: FEU is planning to install submetering on 8 systems to monitor and evaluate the actual energy savings claims. . FEU is

	expecting impact results in late 2012 as referred to in response BCUC IR2.114.2 8. Code and Standard: Not applicable
Measure Lifetime (years)	25 years
Measure Lifetime Determination Methodology	1. Data Sources: Retscreen has a default measure life for Solar thermal within British Columbia as 25 years which is listed http://www.retscreen.net/ang/case_studies_heating_solar_water_heater_house_canada.php 2. Range of Measure Life: 20-40 years a. Solar BC: 20 to 40 years b. US Department of energy: 30 years b. Florida Solar energy center: 30 years c. Ontario Energy Board: 18 years 3. Assumptions: As this technology has a low adoption curve in BC and is lacking the in depth level of monitoring required to quantify a measure life, FEU reviewed industry sources and other programs to assume a 25 year life. 4. Other Utilities: not applicable.
Incremental Cost ($)	$8,500
Incremental Cost Determination Methodology	1.Data Sources: a. The equipment and installation cost was collected from SolarBC's estimation based on a typical home installs 2 collectors and 1 storage tank. 2. Range of Incremental Cost: $6,000 - $10,000. 3. Assumptions: use a medium cost in the range which is $8500 4. Other Utilities: not applicable.

Innovative Technologies for Transportation Emission Reduction (NGV):

FEU provides the following details on its proposed NGV technologies for information only, as these are programs being proposed for the 2012 – 2013 RRA. Although the Commission has determined that NGV related programs are not currently considered appropriate for FEU's EEC portfolio, we believe this information might be of interest to the Commission and Stakeholders.

Innovative Technology (5.4)	NGV Demonstration Program – Waste Management #2
Energy Savings per Installation (GJ)	-1,057 GJ

Energy Savings Determination Methodology	1. Measure Description: a. Baseline technology: b. The Waste Management (WM) seeks to purchase 20 front load, commercial collection vehicles installed with Cummins-Westport ISL-G Compressed Natural Gas (CNG) engines. The engine meets 2010 US EPA emission standards for oxides of nitrogen (NOx) and particulate matter (PM). The project will help to reduce high fuel cost and high exhaust emissions by existing diesel vehicle fleet. c. The vehicles are McNeilus bodies with autocar chassis that would utilize approximately 21,000 GJ of total CNG per year. d. The combustion efficiency of a diesel hauler: no available e. The combustion efficiency of a CNG hauler: not available f. FEI does not presently have the combustion efficiency for the above engines; however an efficiency loss (penalty) of 17% has been applied to CNG haulers compared to diesel. 2 and 3. Data sources/Engineering Analysis: a. Waste Management historic fuel consumption from its diesel vehicles b. Energy content of diesel was derived from the NRCan's GHGenius model (www.ghgenius.com). c. Engineering estimates of fuel consumption from natural gas vehicles 4. Range of savings: not applicable 5. Assumptions: It is assumed that WM is going to purchase the same number of CNG vehicles in 2011 as that of phase 1 in 2010 and saved the same amount of energy as that of 2010. The diesel fuel consumption estimate provided by the customer was 23,400 litres per unit. FEI divided this by a factor of 25.87 (energy content value for diesel is 38.653 MJ/L) to attain an energy value in GJ. An efficiency loss multiple of 17% was also applied, which results in a total of approximately 1,057 GJ per unit. FEI notes this fuel consumption estimate was made for WM's 2010 Phase 1 vehicle additions and fuel consumption may increase in its 2011 Phase 2 vehicle additions. 6. Other utilities: not applicable 7. Impact evaluations: An impact study evaluation is scheduled to be conducted in 2011 on energy savings claim. 8. Code or Standard: not applicable

Measure Lifetime (years)	10 years
Measure Lifetime Determination Methodology	1. Data Sources: Waste Management Inc. 2. Range of measures: not applicable 3. Assumption: not applicable 4. Other utilities: not applicable
Incremental Cost ($)	$40,178 per vehicle
Incremental Cost Determination Methodology	1. Date Sources: a. Commercial truck manufacturer Autocar (based on the specifications for WM's 2010 fleet vehicles). Cost is current as of December 2010. b. Full cost of a diesel hauler: $148,000 c. Full cost of a natural gas hauler: $188,000 2. Range of incremental cost: a. Between $55,000 (mid-2010) to $40,000 (2011) due to changes in the manufacturing cost of NGVs. 3. Assumptions: Cost includes shipping differential (between NG and diesel) 4. Other utilities: not applicable

Innovative Technology (5.5)	**NGV Demonstration Program – City of Vancouver (COV)**
Energy Savings per Installation (GJ)	-1,524 GJ
Energy Savings Determination Methodology	1. Measure Description: a. Baseline technology: b. To address the problem of high prices and high exhaust emissions from existing diesel tractors, the City of Vancouver (COV) seeks to purchase 9 Class 8 tractors installed with Liquefied Natural Gas (LNG). The new operation will utilize approx. 14,000 GJ of LNG. c. The LNG tractors is powered by Westport GX natural gas engine which meets 2010 US EPA emission standards for oxides of nitrogen (NOx) and particulate matter (PM). d. The combustion efficiency of a LNG tractor: not available e. The combustion efficiency of a diesel tractor: not available Based on information from Westport Innovations, no efficiency loss exists between LNG and diesel engines.

	2 and 3. Data Sources/Engineering Analysis: a. Historical diesel fuel consumption data from COV in mid-2010 b. Energy content of diesel was derived from the NRCan's GHGenius model (www.ghgenius.com). 4. Range of savings: none 5. Assumptions: none The diesel fuel consumption estimate provided by the customer was 39,425 litres. FEI divided this by a factor of 25.87 (energy content value for diesel is 38.653 MJ/L) to attain an energy value of 1,524 GJ per unit. 6. Other utilities: not applicable 7. Impact Evaluations: a. An impact study evaluation is scheduled to be conducted in 2011 on energy savings claim. 8. Code or Standard: not applicable.
Measure Lifetime (years)	8 years
Measure Lifetime Determination Methodology	1.Data Sources: City of Vancouver EEC funding application submitted to FEI in mid-2010 2. Range of measure life: not applicable 3. Assumptions: not applicable 4. Other utilities: not applicable
Incremental Cost ($)	$78,000 per vehicle
Incremental Cost Determination Methodology	1. Data Sources: a. EEC Funding Application submitted to FEI in mid-2010. b. Full cost of a diesel tractor: $145,000 c. Full cost of a natural gas tractor: $223,000 2. Range of incremental cost: not applicable 3. Assumptions: Cost includes shipping differential (between LNG and diesel). 4. Other utilities: Not applicable.

Innovative Technology (5.6)	**NGV Demonstration Program – Wastech Services Ltd. (Abbotsford)**
Energy Savings per Installation (GJ)	-7,731 GJ

Energy Savings Determination Methodology	1. Measure Description: a. Baseline Technology: b. Wastech Services Ltd ("Wastech") seeks to purchase 25 Westport GX natural gas engine installed on a KenworthT800 Series Conventional LNG tandem (and/or tri-drive) tractor. The engine meets 2010 US EPA emission standards for oxides of nitrogen (NOx) and particulate matter (PM). c. The combustion efficiency of a LNG tractor: not available d. The combustion efficiency of a diesel tractor: not available Based on information from Westport Innovations, no efficiency loss exists between LNG and diesel engines. 2 and 3 Data Sources/Engineering Analysis: a. Wastech Services Ltd historic fuel consumption from its equivalent diesel vehicles. b. Energy content of diesel was derived from the NRCan's GHGenius model (www.ghgenius.com). 4. Range of savings: none 5. Assumptions: none The diesel fuel consumption estimate provided by the customer was 200,000 litres. FEI divided this by a factor of 25.87 (energy content value for diesel is 38.653 MJ/L) to attain an energy value of 7,731 GJ per unit. FEI notes this fuel consumption estimate was submitted by Wastech to FEI in mid-2010 in their initial EEC Funding Application. 6. Other utilities: not applicable. 7. Impact evaluation: is scheduled to be conducted in 2011 on energy savings claim. 8. Code or Standard: not applicable
Measure Lifetime (years)	8 years
Measure Lifetime Determination Methodology	1.Data sources: a. Wastech Services Ltd 2. Range of measure life: not applicable 3. Assumptions: not applicable 4. Measure lifetime - other utilities: not applicable.
Incremental Cost ($)	$91,000 per vehicle
Incremental Cost Determination Methodology	1. Data Sources: a. EEC Funding Application submitted to FEI in mid-2010. b. Full cost of a diesel tractor: $122,000 c. Full cost of a natural gas tractor: $213,000

	2. Range of incremental cost: none 3. Assumptions: Cost includes shipping differential (between LNG and diesel). 4. Other utilities: Not applicable.

97.2 For the purposes of discounting, does FEU use WACC pre or post tax? Please explain why this is appropriate and if the outcomes change as a result of recent updates to interest forecasts.

Response:

The FEU uses pre-tax WACC adjusted for inflation (i.e. real) for TRC discounting purposes. This is because the FEU treats the program input costs and benefits for estimating benefit cost ratios on a pre-tax basis, hence it is appropriate to use a pre-tax WACC. This is also consistent with BC Hydro's practice of discounting on a pre-tax basis and California Public Utilities Commission's interim decision[23] (Section 3.5.2) on the use of pre tax rate equal to Utilities cost of capital.

The recent evidentiary updates to interest forecast will have an impact on WACC for 2012 and 2013 planned programs only if approved by BCUC. The TRC discount rates will be 6.93% for 2012 and 6.92% for 2013, on a pre-tax basis and adjusted for inflation.

[23] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/101543-02.htm#P234_59317

98.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.1

TRC Inputs

98.1 It appears that in its cost effectiveness screening of demand side measures that FEU includes program administration and net to gross ratios at the measure level. Is it not best practice to screen demand side measures at the measure level first and then screen at a program level where program administration costs are included and a net to gross factor is applied?

Response:

Yes and no. Most of the FEU's programs only contain one measure, so it makes no difference whether screening is done at the measure level or at the program level. As a general rule, in those programs that contain multiple measures, net-to-gross ratios will vary from measure to measure. The FEU's programs that contain multiple measures are contributions to LiveSmartBC, and ECAP (planned program for 2011). The benefit cost approach that has been taken to these 2 programs can be found in the confidential attachments to BCUC IR 1.189.1, and in the attachments provided in response to BCUC IR 2.94.4. LiveSmartBC information can be found in the "28 series" of attachments to BCUC IR 1.189.1, while ECAP information can be found in the "29 and 30 series" of attachments. It can be seen in these attachments that for LiveSmartBC, absent any other information, a net-to-gross ratio of 12% has been applied to all measures, and administration costs have been included on the "Windows and Doors" individual measure tab and so in practice have been applied at the program level. An evaluation of this program is underway by BC Hydro's evaluation group and should it provide different information about net-to-gross ratios for different measures, these will be adjusted accordingly. In the case of ECAP, administration costs have been applied at the program level, and different net-to-gross ratios (cell C11 of the individual plan tabs) applied to different measures.

99.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.1

TRC Inputs

99.1 It appears that in its cost effectiveness screening of demand side measures FEU includes program administration and net to gross ratios at the measure level. Is it not best practice to include program administration and net to gross ratios when screening demand side measures at the measure level and program administration costs are included and a net to gross factor is applied only when screening programs under the TRC methodology at the program and portfolio level?

<u>Response:</u>

Please see the response to BCUC IR 2.98.1.

100.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.1.1

TRC Inputs

"In 2010 and 2011, a distribution adder of $0.16 per GJ was also included in the total avoided costs. The assumed avoided cost for electricity is a levelized $0.12 per kWh and $170 per avoided kW."

Table 3 - 2011 Assumed Retail Rates and Discount Rates

FEI Residential Retail Rate ($/MJ)	$0.0099
FEVI Residential Rate ($/MJ)	$0.0143
FEI Commercial Retail Rate ($/MJ)	$0.0094
FEVI Commercial Rate ($/MJ)	$0.0169
Residential Electric Rate ($/kWh)	$0.0827
Commercial Electric Rate ($/kWh)	$0.0769
Electric Capacity Charge ($/kW)	$52.00
FortisBC Rate of Inflation	1.9%
BC Hydro Rate of Inflation	2.00%
FEI Discount Rate	7.15%
FEVI Discount Rate	6.89%
BC Hydro Discount Rate	6%
Participant Discount Rate	6%

100.1 Please explain how the distribution adder was set at $0.16. Does the distribution adder include distribution and transportation costs, capacity costs, tolls, and system improvement charges? If so, why does the distribution adder stay constant at $0.16 and not inflate over time?

Response:

The distribution adder was set at $ 0.16/GJ for FEI territory based on Commission Order No. G-152-07 regarding the TGI/TGVI system extension and customer connection policy (page 30).

The distribution adder represents the system improvement charges only. These charges represent the per GJ allowance for distribution system upgrades as a result of adding new customers. FEI currently holds the system improvement charge as a constant value as this was approved by the Commission as a set value in Order No. G-152-07. This is also consistent with FEI's current practice of holding that value constant for system extension and customer connections. Additionally, since system improvement charges are only a component of the overall total avoided commodity costs, holding these charges constant is appropriate in its current benefit-cost practice.

100.2 How did FEU determine the levelized avoided cost for electricity and the residential and commercial electric rates? If the residential electric rate is based on BC Hydro's Tier 2 rate for the Residential Inclining Block Rate please justify why Tier 2 rates were used rather than a blended Tier 1/Tier 2 rate.

Response:

The Residential and commercial retail rates are derived from BC Hydro's tariff documents.[24] Although the Tier 2 rate is now 9.62 cents/kWh, FEU is still using the initial rate of 8.27 cents /kWh[25] for modelling purposes and will update this figure accordingly in future models. Electricity retail rates impact only the participant cost test and using a lower value of 8.27 cents in our model currently understates the participant benefit for those programs where there is a reduction in both gas & electricity usage.

An average SFD home with no electric space heating consumes about 10,502[26] kWh/year of electricity. This equates to about 875 kWh on a monthly basis - higher than the allowed 675[27] kWh as the threshold for Tier 1. Therefore the Companies' view is that it is reasonable to assume that most of the participants who take advantage of the EEC programs that involve gas and electricity savings would fall within Tier 2 for electricity savings and hence it is appropriate for screening DSM cost effectiveness measures.

The levelized avoided cost of electricity has been rounded off to 12 cents/kWh and is based on BC Hydro's result of 0.124/kWh[28] from the recent Clean Power Call RFP process report (page 12). It represents BC Hydro's latest marginal cost for electricity. Prior to the Clean Power Call being finalized there were a number of references in BC Hydro's 2008 LTAP regulatory proceeding to the expectation that the results were expected to be in the range of $120/MWh

24 https://www.bchydro.com/youraccount/content/residential_rates.jsp
25 BCH F2011 RRA, Appendix A1, Page 2, Table 2.
26 BC Hydro Residential Electricity Intensity Trends, March 2011
27 1350/2= 775 Kwh on a monthly basis. https://www.bchydro.com/youraccount/content/residential_rates.jsp
28 http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/acquiring_power/2010q3/cpc_rfp_process_report.Par.0001.File.CPC_RFP_Process_Report_August_3_2010.pdf

($0.12/kWh). The levelized cost of electricity only impacts TRC for those programs where this is an impact on gas & electricity usage.

100.2.1 Please explain why FEU does not inflate the levelized avoided cost of electricity in future years in its cost effectiveness screening.

Response:

The FEU are being consistent in their cost effectiveness screening by keeping the levelized avoided cost of electricity as a constant value for all years in the absence of any specific information on potential future “real” increases in the avoided cost from BC Hydro (i.e. those that are in excess of inflation). This practice is also consistent with other inputs costs such as FortisBC Inc. and BC Hydro electric retail rates that are currently held constant for all the years.

101.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.189.2, 1.201.1

New Initiatives Programs – Screening and Incentive Level

101.1 In the cost-effectiveness workbooks the EEC incentive level for the New Initiatives programs is unclear. Did FEU screen these measures using the full incremental cost of installation? If so, does FEU plan to pay for the full incremental cost of installation for Thermal Energy for Schools projects and Solar Thermal projects from EEC funds? If not, what is the planned incentive level for these two programs?

Response:

The cost-effectiveness workbooks referenced in responses to BCUC IRs 1.189.2 and BCUC IR 1.201.1 do not include the level of incentives as they do not affect the results from the TRC and SCT. The amounts listed in the workbooks are estimated incremental costs for the equipment and installation. As quoted from the California Standards Practice Manual, pg. 18 "The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test."

The FEU are planning to further develop program design for New Initiative programs and establish the appropriate level of incentives geared to drive adoption once a decision on funding approval is made. The determination of incentive levels is required prior to simulating the RIM, UC and Participant calculations. Those incentive levels will be presented to the EEC Stakeholder group for their comment and input. The FEU will also include the RIM, UC and Participant test calculations for the New Initiative Program areas in addition to the total Portfolio level reporting in the annual report.

101.1.1 Does FEU plan to pay the full incremental cost per installation of $7,500 for solar direct water heating systems, $39,400 for Solar Air, and $55,000 for Solar Commercial?

Response:

Please see the response to BCUC IR 2.101.1.

101.2 Do the school customers or Solar Thermal customers pay any of the installation or project costs?

Response:

Contribution levels by program participants to energy efficiency project costs, which include installation, will be developed during detailed program design, which the FEU have not commenced for New Initiative programs at this time. Program design will be developed once a funding decision has been made for New Initiative Programs.

101.3 What guidelines will FEU use to determine the amount of customer incentive or reimbursement for installation of Thermal Energy for Schools measures and Solar Thermal projects.

Response:

Incentive levels or reimbursements will be developed during detailed program design which the FEU have not commenced for New Initiative Programs at this time. Program design will be developed once a funding decision has been made for New Initiative Programs. Generally speaking though, the FEU have set incentive levels based on what degree of incentive, whether paid to the customer or to other actors in the DSM marketplace such as installers or suppliers, will be required to encourage the implementation of a DSM measure. Incentive levels are determined through research with customers and actors in the DSM marketplace to determine possible technical and market barriers, researching the technology and/or measure for the required inputs to simulate the appropriate incentive and by looking at other utilities' programs, their incentive levels and corresponding degrees of customer participation. Those incentive levels will be presented to the EEC Stakeholder group for their comment and input.

102.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.198.1, 203.2.2

New Initiatives - Solar Thermal

For 2010:

Program	Program Description	Incentive Expenditures ($000s)
Solar Water Heating PSECA Program	Rebate program to encourage the adoption of solar water heating systems in provincial sector buildings to reduce natural gas consumptions.	$372

And planned for 2011;

Program	Program Description	Incentive Expenditures & Non-Incentive Expenditures ($000s)
Solar Air Heating PSECA Program	Rebate program supporitng the BC Government to encourage the adoption of solar water heating systems in provincial sector buildings to reduce natural gas consumption.	$73
SolarBC Schools Incentive Program	Rebate program supporting the BC Government to encourage the adoption of solar water heating systems in schools to reduce natural gas consumption and increase awareness.	$27
Solar Residential Hot Water - Pilot	Rebate pilot to asses the performance and energy savings for solar thermal hot water systems within the City of Vancouver for residential applications	$76

102.1 Other than the billing analysis planned for 2012, what other impact evaluation data or other evidence does FEU have from its Solar Water Heating PSECA Program, its Solar Air Heating PSECA Program and its SolarBC Schools Incentive Program? Please provide the details of any EM&V that has taken place on these programs, the firm completing the studies, and the results of the studies.

Response:

Other than the billing analysis for the Solar Water Heating PSECA Program, Solar Air Heating PSECA Program and SolarBC Schools Incentive Program, the FEU plan to identify relative program costs and benefits. As the FEU were not involved in developing the design and the launch of those provincial programs, the FEU plan to work with both the PSECA and SolarBC program delivery agents to assess their program delivery, from design to implementation for those programs. This will include identifying bottlenecks, efficiencies, what worked, what did not work, constraints, and potential improvements. The FEU plan to gather full evaluation data late

2012 for the Solar Water Heating PSECA program and late 2013 for both the Solar Air Heating PSECA Program and the SolarBC Schools Incentive program. This time lapse is required in order to gather the adequate evaluation data once all systems have been commissioned and operational for at least one full calendar year. Once the Companies have reviewed the data, should the results of those programs prove to be acceptable, program design and development would begin. Further details on the evaluation timing can be found in response BCUC IR 2.114.2.

103.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.198.3, 203.1

New Initiatives - Solar Thermal

"The FEU anticipate launching 2 pilots within Innovative Technologies in 2011, one being the Solar Residential Hot Water pilot that was launched in Q1 of 2011 and the second being the City of Vancouver Multi-Unit Residential Building (MURB) pilot which is expected to launch the end of Q3 of 2011."

103.1 Please explain why FEU is requesting $2 million in annual budget for each of 2012 and 2013 for its Solar Thermal Hot Water – Residential program when it is launching its Solar Residential Hot Water pilot in Q1 of 2011?

Response:

To clarify, the Solar Residential Hot Water pilot is being run by the City of Vancouver. The FEU's participation in this pilot is based on a $50,000 commitment to reduce the high incremental cost for 30 participants to increase the adoption of solar hot water in Vancouver households until the end of December 31, 2011. Please refer to the 2010 EEC Annual Report, attached as Appendix K-4 to Exhibit B-1, under Section 10.1.5.3.4 Solar Residential Hot Water - PILOT PROGRAM for further details concerning this pilot.

The funding requested for Solar Thermal activity within New Initiatives is a separate funding envelope. Should a program around Solar Thermal prove to be viable following completion of the pilot, funding would then be there for a full program for Solar Thermal. The pilot has not yet been completed and we expect results to be available in 2012. Further details on the evaluation timing can be found in response BCUC IR 2.114.2. Once the Companies have reviewed data from the pilot, and should results prove to be acceptable, program design and development would begin. Should this not prove to be the case, a full program would not be implemented, and the funding envelope would not be spent. Further details on the evaluation framework can be found in response BCUC IR 1.212.2.1. Pilot results, and any subsequent program will be presented to the EEC Stakeholder group for their comment and input, as is done for all EEC programs.

The approach of having the Commission approve Program Areas of activity, and giving the Companies the responsibility of managing individual programs within the cost-effectiveness guidelines and using the accountability mechanisms of the EEC Stakeholder Group and EEC Annual Report was established in the Commission's Decision in the 2008/2009 EEC Application on pages 41-42.

103.2 Does FEU believe it is best practice to evaluate results of a pilot on a certain technology or measure before starting a program on that technology or measure?

Response:

The FEU believe that this varies from measure to measure and program to program. There are some measures and programs where it is not necessary to run a pilot first, because that measure or a similar program may have been undertaken in other jurisdictions and data or best practices from those other jurisdictions can be used as the basis for activity by FEU. Where there is a lack of industry data for measures and programs, the Companies will take a more cautious approach and run a small limited pilot prior to launching a full program. Please see also the response to BCUC IR 2.103.1.

104.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.189.2, 1.202.3

New Initiatives – Furnace Scrap-it

104.1 Please provide the data FEU used to project 8,500 installations per year. Please justify the projected installations at this level.

Response:

The Furnace Scrap-it Program estimated target of 8,500 units for 2012 and 2013 budgeting purposes was based on the following data. In the 2008-2009 ENERGY STAR® Heating System Upgrade program the FEU provided 8,429 rebates for furnaces purchased between September 2008 and December 31, 2009, and an additional 9,137 rebates in partnership with LiveSmart BC. Discussions with industry partners at the 2010 CPR Achievable Potential work shop suggested 2012 estimates of 6,028 units as the lower limit and 16,423 units as the upper limit. In the 2008 REUS study, almost 25% of the FEU's customers suggested that their furnaces were more than 20 years old, while the 8,500 unit target represents only 1% of the FEU's residential households. Based on these findings and informal discussions with industry partners, it is reasonable to assume that 8,500 units can be achieved. Program design has not yet been completed and further consultation with relevant stakeholders will provide better insights into the actual program uptake and program design considerations.

The FEU believe that these targets will be achieved through effective marketing and collaborative partnerships. Since EEC program funding in 2009, the FEU's residential program offering as a whole has more visibility in the market, making new program introductions more likely to get greater traction at the outset. The establishment of the FEU contractor program and a proposed contractor incentive will provide greater buy-in from trade allies to help promote the program to customers. The FEU will collaborate with heating system manufacturers to find ways to integrate the offer into their marketing strategies through co-operative advertising opportunities. Partnerships with LiveSmart BC and the electric utilities will further drive program participation.

In summary, based on past program participation levels, effective marketing, and partnerships with trade allies, LiveSmartBC and other electric utilities the FEU believe that the proposed Furnace Scrap-It program target of 8,500 participants annually is achievable.

105.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.189.2

New Initiatives – Thermal Energy for Schools and Solar Thermal

105.1 Is it likely that this backup supply will only be required for a few days per year and it is likely that these days will coincide with FEU's peak days?

Response:

When an alternative energy source is being utilized for a customer's base load thermal energy requirements there is a decreased overall peak load contribution for gas within the system than would otherwise be present if the customer was using gas for the most or all of its thermal load requirements. So while the backup gas supply for an alternative energy project may only be required on a limited basis in the winter months, and likely will be needed on peak days, the contribution to the overall peak energy requirements from gas is diminished relative to a system that runs purely on natural gas. The impact of alternative energy sources on the natural gas system as a whole will happen over time, regardless of whether FEI offers this program or not, as energy consumers in BC look to meet their energy needs in a more environmentally friendly way.

105.2 Has FEU considered a rate schedule for natural gas supply for these New Initiative customers that factors in the cost and load factor of peak natural gas supply? If not, why not?

Response:

The Companies wish to clarify that the "New Initiatives" are a proposed area of activity for EEC funding, in which eligible customers will be able to participate, rather than a customer class that would have its own rate schedule.

The FEU are in the process of determining what natural gas rate schedule offerings are required to support thermal energy customers and anticipate filing rate schedules as part of the Rate Design Phase 'B' Application in 2012.

106.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.207.1

Societal Cost Test – Social Discount Rate

106.1 Do the other jurisdictions that use a social discount rate treat their DSM costs as capital and amortize them over a fixed time period? Please list the jurisdictions that use a social discount rate and indicate whether or not they "rate-base" their DSM expenditures.

Response:

Eight states require a societal discount rate in cost-effectiveness calculations. They are:

- Iowa
- Maine
- Massachusetts
- Minnesota
- Montana
- Oregon
- Vermont
- Wisconsin

Of these, Minnesota, Montana, and Wisconsin allow for the capitalization and amortization of DSM program costs. In Minnesota, a carrying charge based on the utility weighted average cost of capital is applied to DSM expenditures. In Wisconsin, utilities may use the same rate of return for DSM expenditures as for capital improvements. In Montana, utilities may apply a 2% adder to the rate of return on equity for conservation investments.

Of five states that utilize a societal discount rate but do not allow for amortization in DSM cost recovery, three —Maine, Oregon, and Vermont— have designated third-party organizations that operate all energy-efficiency programs on behalf of utilities. A fourth (Massachusetts) does not allow capitalization but does provide performance incentives to utilities that achieve a certain portion of their projected savings. Vermont and Minnesota offer similar incentives and

Wisconsin has also offered similar incentives in the past. Iowa neither allows capitalization of DSM expenditures nor has an incentive structure in place for achieved savings.

106.2 Of those jurisdictions that use the Societal Cost Test, what is the mechanism for the cost recovery of the DSM spend in each jurisdiction? Please elaborate.

Response:

Table 1 below illustrates the regulatory structure of DSM cost recovery in each of the eight states listed in BCUC IR 2.106.2. Specific funding mechanisms and performance incentives are provided for each state.

Table 1: Program Operation and Recovery, Funding and Incentive Procedures by State

State	Program Operator[29]	Cost Recovery	Funding Mechanism	Other Performance Incentives	Fuel
Iowa	Individual Utility	Expensed	Utilities recover annual expenses of DSM programs through an adder on customer bills. An energy charge collects planned DSM expenses and is annually reconciled through an automatic adjustment.	None	Gas and Electric
Maine	State-Designated Entity	Expensed	A flat fee per kWh is included in retail rates. This revenue is placed in a statewide conservation program fund and is used as the annual operating budget for Efficiency Maine.	None	Electric

[29] Several states have created organizations for the specific purpose of administering energy efficiency programs. These organizations are Efficiency Maine, the Energy Trust of Oregon, and Efficiency Vermont. In Wisconsin, utilities participate collectively in the Focus on Energy program, as required by the public utilities commission.

State	Program Operator[29]	Cost Recovery	Funding Mechanism	Other Performance Incentives	Fuel
Massachusetts	Individual Utility	Expensed	A flat fee per kWh/therm is included in retail rates and is used to fund energy efficiency and conservation activities.	Programs that meet planning goals may earn an incentive equal to the product of the average yield of the three-month US Treasury Bill and direct program costs, amounting to roughly 5% of program costs. For reference, the Modified TRC test discount rate used in Massachusetts is based on a ten-year average Treasury Bill rate.	Gas and Electric
Minnesota	Individual Utility	Rate-based	Utilities must dedicate 1.5% of gross operating revenues to conservation improvement programs. These costs, as well as a carrying charge applied on the balance, are recoverable through rate increases. The carrying charge is based on the utility weighted average cost of capital.	Utilities are awarded a portion of net benefits based on the percentage of targeted savings achieved. Utilities achieving 91% of the savings goal are eligible for this incentive.	Gas and Electric

State	Program Operator[29]	Cost Recovery	Funding Mechanism	Other Performance Incentives	Fuel
Montana	Individual Utility	Rate-based	An amount equal to 2.4% of each utility's 1995 retail sales revenue are collected through rate payments on an annual basis as a universal system benefits charge and used to fund energy efficiency and conservation activities. Amortization periods are to be prescribed by the commission.	In legislation not yet applied to specific utilities, the commission is authorized to allow a 2% adder to the rate of return on equity for conservation investments.	Gas and Electric
Oregon	State-Designated Entity	Expensed	A public purpose charge equal to a specific percent of total utility revenues is used to create a public purpose fund, administered by an independent organization. The percent varies by utility and fuel type.	None.	Gas and Electric
Vermont	State-Designated Entity	Expensed	Utility-specific adders to retail rates are used to fund a third-party energy efficiency utility, which administers DSM programs.	The independent energy efficiency program operator is eligible for performance incentives of up to 3.5% related to progress against program goals.	Electric

State	Program Operator[29]	Cost Recovery	Funding Mechanism	Other Performance Incentives	Fuel
Wisconsin	State-Wide Common Effort	Rate-based	Utilities are required to spend 1.2% of their annual operating revenues on energy efficiency and renewable resource programs. Utilities are entitled to earn the same rate of return on energy-efficiency investments as with capital improvements.	None. Wisconsin had performance incentive in the 1990s, but it is no longer active.	Gas and Electric

106.3 If a 3% social discount rate were approved, how would FEU reconcile the fact that FEU's true cost of the EEC funds would be at the Companies' WACC while the evaluation of the use of the funds (the cost effectiveness screening) would be at 3%? In other words, please reconcile and explain the disconnect that occurs as the real costs incurred would equal the WACC but planning level considerations would occur using social discount rate.

Response:

This Information Request combines two disparate elements: economic analysis of DSM initiatives and the financial treatment of DSM costs. The economic analysis of DSM initiatives, i.e., cost-effectiveness analysis, is used to determine which DSM initiatives are worthy of investment. Once programs and initiatives are determined to be worthy of investment, and are selected for implementation, these investments are subjected to financial treatment and recovery of associated costs from customers. While economic analysis measures the impact of a project on the society as a whole, the financial treatment of the same project reflects the accounting practices and perspective of the utility and regulators, and conceptually, how the utility finances any approved investment.

For DSM programs the economic analysis assesses the overall impact of the project on the society as a whole. In this case it is the change in the total cost of the resource (including externalities such as reduced GHG emissions) to society from the perspective of current and future generations – hence the social discount rate of 3%. This analysis is used to determine in which measures the utility, and by proxy, society, should be implemented and delivered to the customers of that utility.

The financial treatment of the investment by the utility reflects how to pay for the programs. For example, the costs of the DSM initiatives can be deferred and amortized over a ten-year period, with a carrying cost based on the utility's weighted average cost of capital (WACC).

A simple analogy is the decision to rent a home versus purchasing a home. An analysis of the benefits of purchasing a home includes the avoidance of rental payments, not only for the purchaser but possibly also for their children, or even grandchildren. This is the economic analysis that is used to make the decision to purchase or not. Calculation of the mortgage with its associated term and interest cost is the financial treatment aspect of the process. While both analyses concern the same project and are conducted in monetary terms, the objectives are quite different. The economic analysis is related to the long term decision to invest in a house (or in a DSM program), while the financial treatment deals with how to pay for it.

Similar decisions are made all the time in the utility industry. For example, electric utilities have been mandated to provide electric service to every community regardless of cost, and recover those investments with a carrying cost based on the WACC. Yet the original economic decision to electrify at least implicitly assumes the benefits to each community will eventually outweigh the costs, which is akin to a zero societal discount rate.

107.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.201.1.1

Societal Cost Test

107.1 Please add the following three scenario analyses to the table provided in FEU Response to BCUC IR 1.201.1.1 showing the cost effectiveness test results for the New Initiative Programs:

Response:

Please see the response to B CUC IR 2.107.2.

107.2 Please add the following three scenario analyses to the table provided in FEU Response to BCUC IR 1.201.1.1 showing the cost effectiveness test results for the New Initiative Programs:

Scenario 13. 3% Discount Rate, 10% Adder, Traditional Avoided Cost of Gas
Scenario 14. 3% Discount Rate, 20% Adder, Traditional Avoided Cost of Gas
Scenario 15. 3% Discount Rate, 10% Adder, Biomethane Avoided Cost of Gas
Scenario 16. 3% Discount Rate, 20% Adder, Biomethane Avoided Cost of Gas
Scenario 17. 4% Discount Rate, 10% Adder, Traditional Avoided Cost of Gas
Scenario 18. 4% Discount Rate, 20% Adder, Traditional Avoided Cost of Gas
Scenario 19. 4% Discount Rate, 10% Adder, Biomethane Avoided Cost of Gas
Scenario 20. 4% Discount Rate, 20% Adder, Biomethane Avoided Cost of Gas
Scenario 21. 5% Discount Rate, 10% Adder, Traditional Avoided Cost of Gas
Scenario 22. 5% Discount Rate, 20% Adder, Traditional Avoided Cost of Gas
Scenario 23. 5% Discount Rate, 10% Adder, Biomethane Avoided Cost of Gas
Scenario 24. 5% Discount Rate, 20% Adder, Biomethane Avoided Cost of Gas

Response:

Results of the scenarios from BCUC IR 1.201.1.1 and the scenarios outlined above are presented in Table 1 below. For ease of reference, the results from Scenarios 1 – 12 have been included, and the base case of a 30% adder, biomethane avoided cost of gas, and 3% discount rate are highlighted in row 4 of the table. The response to the question posed resulted in an additional 84 societal test analyses.

Table 1: Benefit-cost ratios for Societal test scenarios

Scenarios (#)		TES for Schools Elementary	TES for Schools Secondary	TES for Schools Average	Solar Thermal - Residential	Solar Thermal - Commercial	Solar Thermal - Air	Furnace Scrap-it Program
1	• 7.15% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.26	1.18	0.86	0.35	0.31	0.25	0.85
2	• 3% Discount Rate • 30% Adder • Traditional Avoided Cost of Gas	(0.26)	0.68	0.35	0.39	0.34	0.28	0.98
3	• 3% Discount Rate • No Adder • Biomethane Cost of Gas	0.30	1.32	0.97	0.41	0.36	0.30	0.91
4	• 3% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.40	1.72	1.26	0.53	0.47	0.38	1.18
5	• 4% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.35	1.56	1.14	0.47	0.42	0.34	1.09
6	• 5% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.32	1.42	1.04	0.43	0.38	0.31	1.00
7	• 6% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.29	1.30	0.95	0.39	0.34	0.28	0.97
8	• 7.15% Discount Rate • No Adder • Traditional Avoided Cost of Gas	(0.18)	0.31	0.14	0.19	0.16	0.13	0.56
9	• 6% Discount Rate • No Adder • Biomethane Cost of Gas	0.22	1.00	0.73	0.30	0.26	0.21	0.71
10	• 7.15% Discount Rate • 30% Adder • Traditional Avoided Cost of Gas	(0.24)	0.40	0.18	0.24	0.21	0.17	0.70
11	• 7.15% Discount Rate • No Adder • Biomethane Cost of Gas	0.20	0.91	0.66	0.27	0.24	0.19	0.68
12	• 3% Discount Rate • No Adder • Traditional Avoided Cost of Gas	(0.20)	0.52	0.27	0.30	0.26	0.22	0.76
13	• 3% Discount Rate • 10% Adder • Traditional Avoided Cost of Gas	(0.22)	0.58	0.30	0.33	0.29	0.24	0.83
14	• 3% Discount Rate • 20% Adder • Traditional Avoided Cost of Gas	(0.24)	0.63	0.33	0.36	0.32	0.26	0.91
15	• 3% Discount Rate • 10% Adder • Biomethane Cost of Gas	0.34	1.45	1.07	0.45	0.40	0.32	1.00
16	• 3% Discount Rate • 20% Adder • Biomethane Cost of Gas	0.37	1.59	1.16	0.49	0.43	0.35	1.09
17	• 4% Discount Rate • 10% Adder • Traditional Avoided Cost of Gas	(0.22)	0.50	0.25	0.29	0.26	0.21	0.76
18	• 4% Discount Rate • 20% Adder • Traditional Avoided Cost of Gas	(0.24)	0.55	0.28	0.32	0.28	0.23	0.83
19	• 4% Discount Rate • 10% Adder • Biomethane Cost of Gas	0.30	1.32	0.96	0.40	0.35	0.29	0.92
20	• 4% Discount Rate • 20% Adder • Biomethane Cost of Gas	0.33	1.44	1.05	0.44	0.39	0.32	1.00
21	• 5% Discount Rate • 10% Adder • Traditional Avoided Cost of Gas	(0.21)	0.44	0.21	0.26	0.23	0.19	0.70
22	• 5% Discount Rate • 20% Adder • Traditional Avoided Cost of Gas	(0.23)	0.48	0.23	0.28	0.25	0.20	0.76
23	• 5% Discount Rate • 10% Adder • Biomethane Cost of Gas	0.27	1.20	0.88	0.36	0.32	0.26	0.85
24	• 5% Discount Rate • 20% Adder • Biomethane Cost of Gas	0.29	1.31	0.96	0.39	0.35	0.28	0.92

107.3 Which proposed condition of the SCT, the social discount rate at 3%, the 30% deemed adder or the biomethane avoided cost of gas, has the greatest effect on whether the New Initiative programs pass the SCT? In other words, under which condition does the most number of programs pass the SCT?

Response:

The scenarios outlined above and those included in the response to BCUC IR 1.201.1.1 show that more New Initiatives pass cost-effectiveness screening when using a 3% discount rate, 30% adder, and biomethane avoided gas costs (scenario 4 in the previous table). Cost-effectiveness of these initiatives, however, is most sensitive to avoided gas costs. To illustrate sensitivity, FEU analyzed each initiative starting from a base case of using the 3% discount rate, 30% adder, and biomethane avoided costs (Scenario 4 in the table above). Cost-effectiveness was calculated as each variable was separately adjusted in 10% increments. The graphs below illustrate the sensitivity to each variable. The greater the change in cost-effectiveness due to an adjustment to the variable, the greater the slope associated with that variable in the graphs. While discount rates and varying adders clearly have an impact on whether a New Initiative is cost-effective or not, the avoided cost of gas has the highest impact of the three variables on the results. This underlines the impact of variable gas prices on DSM initiatives. Comparisons within and between initiatives show that avoided costs have the greatest sensitivity. The scale of the graphs, which vary according to the Societal test results for each initiative, must be considered in any comparison of slopes between initiatives.

Figure 1: Cost-effectiveness sensitivity – Furnace Scrap It Program

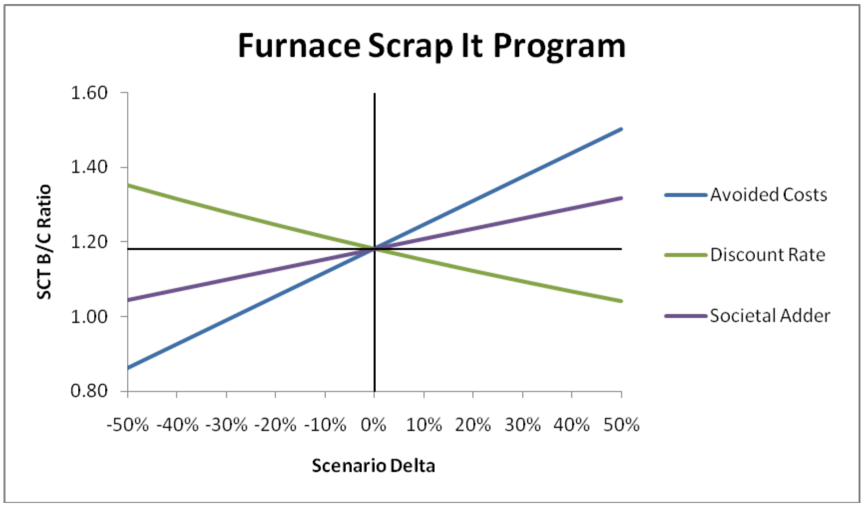


Figure 2: Cost-effectiveness sensitivity – Solar Thermal Air

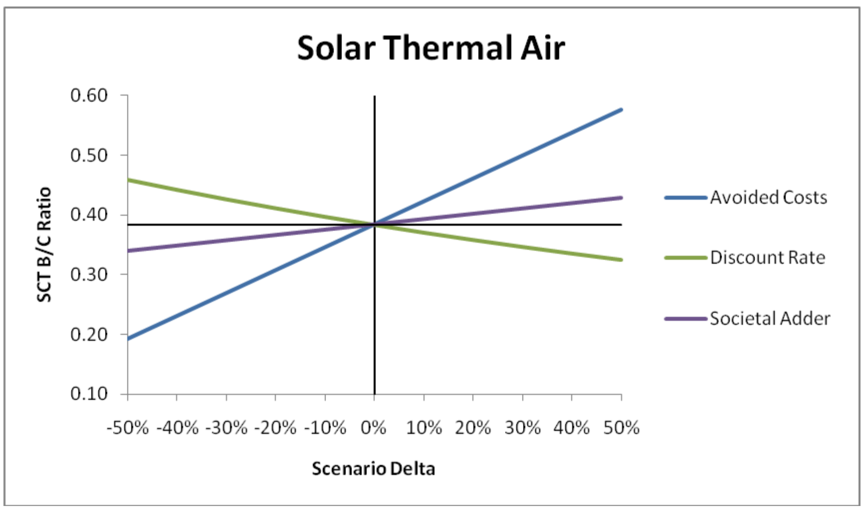


Figure 3: Cost-effectiveness sensitivity – Solar Thermal (commercial)

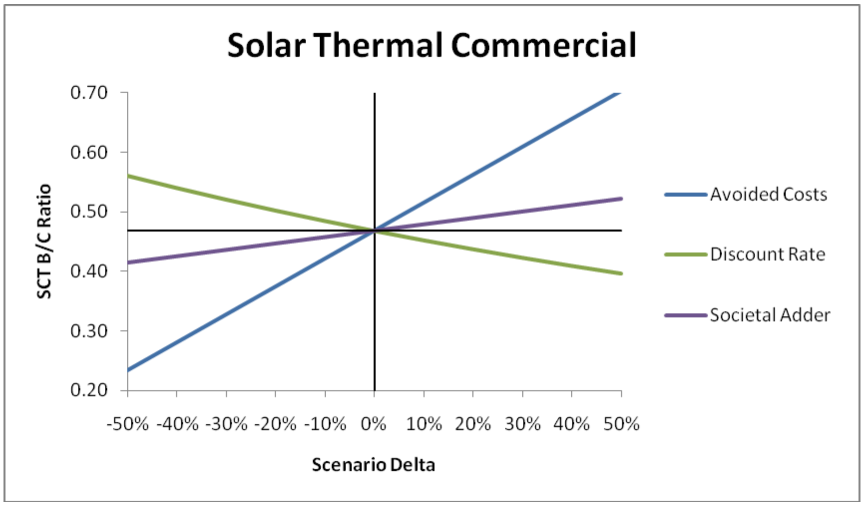


Figure 4: Cost-effectiveness sensitivity – Solar Thermal (residential)

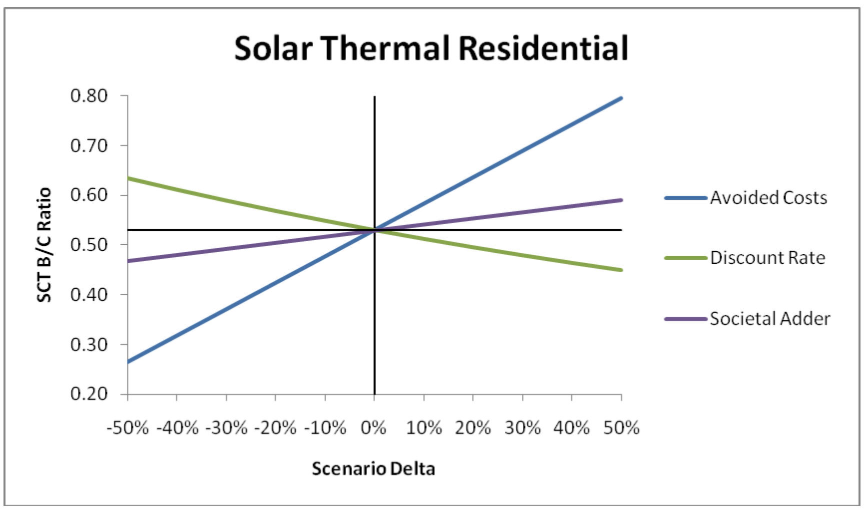


Figure 5: Cost-effectiveness sensitivity – Thermal Energy for Schools (average)

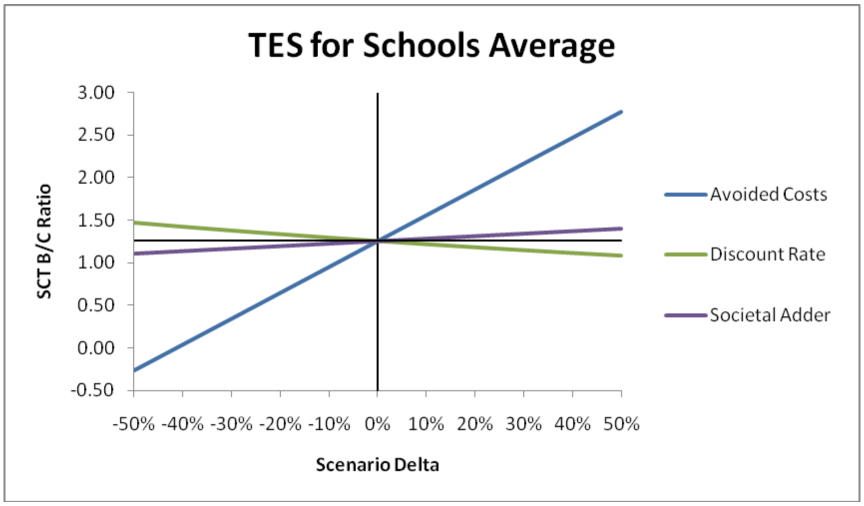


Figure 6: Cost-effectiveness sensitivity – Thermal Energy for Schools (elementary)

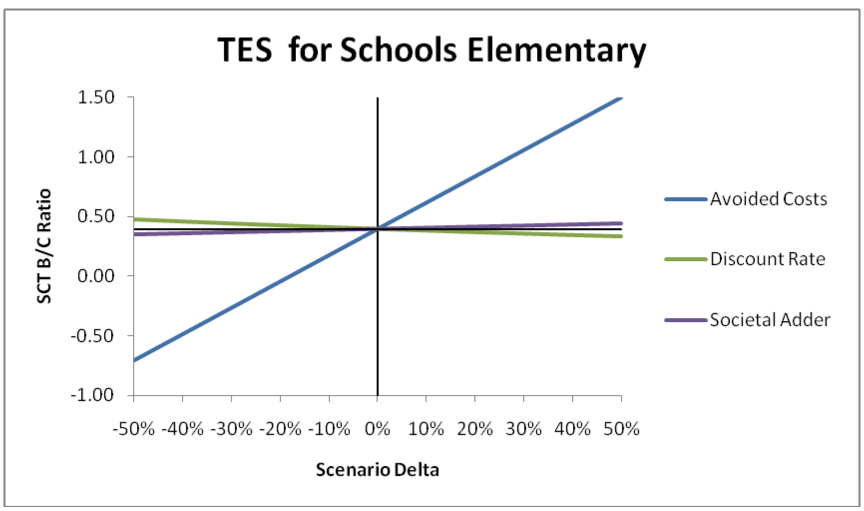
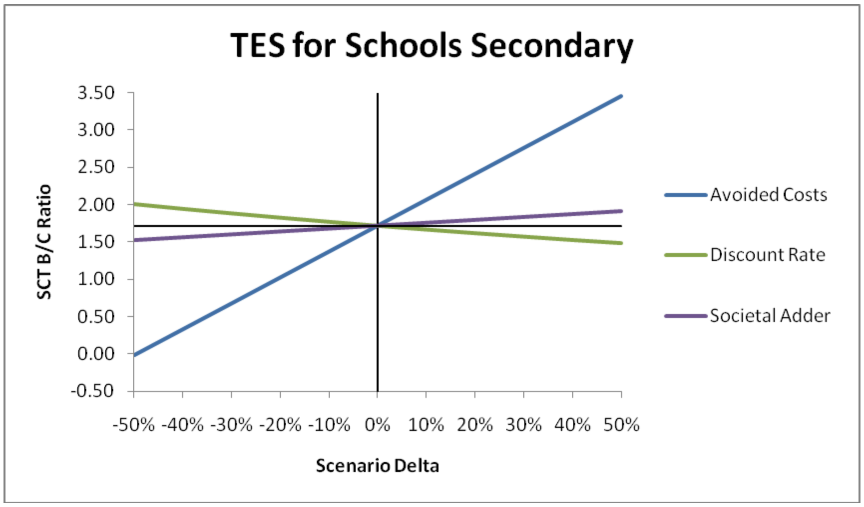


Figure 7: Cost-effectiveness sensitivity – Thermal Energy for Schools (secondary)



108.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.200.2, 1.200.3

Societal Cost Test – Greenhouse Gas Emissions

"Once that quantity has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO2 value in cost-benefit calculations, and some do not. California includes a forecast of GHG values in the avoided costs used to perform the cost-effectiveness tests..."

"Thus some jurisdictions include a value for GHG emissions in cost-effectiveness tests, and some do not."

108.1 Please list all the jurisdictions that include a value for GHG emissions in cost-effectiveness tests.

Response:

A broad search of the market within the time permitted found two examples of a value being applied to environmental factors in cost-effectiveness tests. This search was not comprehensive and as a result there may be other jurisdictions that include a value for GHG emissions in their cost-effectiveness tests. A complete comprehensive search would require hiring of a research vendor and would likely take several weeks or months to finalize.

The two examples found were in California and Minnesota and are described below.

California includes a forecast of GHG values in the avoided costs used to perform their cost-effectiveness tests. This was determined from the report, "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers"[30]. However, it is not clear how exactly GHG emissions are monetized. The white paper, "Integrated Demand - Side Management (IDSM) Cost - Effectiveness Framework White Paper"[31], states on page 50:

> *The inclusion of greenhouse gas benefits is already part of the SPM (California Standard Practice Manual) approach and is used for all IDSM resources that use the avoided - cost calculator. The greenhouse gas benefits for IDSM resources will, thus, be integrated in a routine way. Substantial controversy has surrounded the proxy values in use for greenhouse gas benefits adopted by the CPUC. It was expected that if California adopts a market - based cap - and - trade approach to value greenhouse gas emissions then proxy estimates are not (to) be needed.*

Xcel Energy in Minnesota includes what they refer to as an "environmental externality" in their Societal Cost Test. Page 650 of the report, "Xcel Energy 2010/2011/2012 Triennial Plan: Minnesota Electric and Natural Gas Conservation Improvement Program,"[32] describes the environmental externality input as "Environmental Factors (Emissions) Avoided". On this same page the report states that:

> *"Environmental Externality = $2.80/MWh in 2010, $2.82/MWh in 2011, averages $0.30/MWh each year for 2012+. Drop due to an assumed CO2 Cap-n-Trade mechanism in place beginning 2012."*

30 http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

31 https://www.pge.com/regulation/EnergyEfficiency2009-2011-Portfolio/Other-Docs/SDGE/2011/EnergyEfficiency2009-2011-Portfolio_Other-Doc_SDGE_20110315Atch01_207817.pdf

32 http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/2010-11-12Triennial_FINAL_FILED.pdf

108.1.1 For each jurisdiction please describe how exactly GHG emissions are monetized and included in cost-effectiveness tests.

Response:

Please see the response to BCUC IR 2.108.1.

108.2 Please propose all possible variations of the Societal Cost Test that are feasible for FEU, other than using the ceiling price of biomethane, that include a monetization of green house gas emissions, assuming the carbon tax remains an input into the test. Please comment which variation is preferred and why.

Response:

Recognizing that merely adding the carbon tax to avoided costs may understate the overall value of greenhouse gas emission reductions, any of the inputs outlined below could also be used.

- Use the amount in BC Hydro's latest Call for Clean Power as the basis for avoided cost of gas
- Deemed adders to the avoided cost of gas in the form of a dollar or percentage
- Including greenhouse gas reduction benefits in the overall non-energy benefit (NEB) adders, or
- Further reductions in the societal discount rate.

One or more of these input changes would be appropriate. The first approach recognizes the price that the utility marketplace (BC Hydro) is willing to pay for GHG-free energy supply, and recognizes that the result of natural gas DSM is generally equivalent to GHG-free energy supply. The price for green power is $124.2/MWh, which would result in an avoided cost of gas of $34.47/GJ. The second approach would involve an adder to the avoided cost of gas. The third approach would be similar, but the adder would be grouped with other NEBs. Turning to the last option, some economists argue that the societal discount rate should be lowered to zero or even be negative to account for intergenerational equity issues arising from climate change.

Although FEU's preference is to use the ceiling price of biomethane as the alternative resource that best reflects a "green" gaseous fuel in British Columbia, the Companies' next best preference would be to use the amount of BC Hydro's Call for Clean Power, adjusted for the lower efficiency of natural gas space and water heating equipment, because as noted above, that value most closely approximates the value that a utility has placed on green energy supply. Deemed adders to the avoided cost of market gas or lower discount rates will not address the issues of gas price volatility and its effect on changing natural gas DSM cost-effectiveness.

109.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.200.2

Total Resource Cost Test – Greenhouse Gas Emissions

"The Companies do factor GHG emission reductions into its cost-effectiveness test in that the carbon tax is factored into the avoided cost benefit in their cost-effectiveness screening for NGVs, as with all EEC initiatives other than B.C.'s carbon tax, there is no formalized price for carbon, which makes factoring GHG emission reductions into cost-benefit analysis a challenge."

109.1 Please confirm that FEU factors the carbon tax into the incremental cost of gas (real) that is then factored into the avoided cost benefit for every one of its EEC programs.

<u>Response:</u>

The FEU confirm that for all its EEC programs where a cost-effectiveness test is performed, the FEU factor the carbon tax into the avoided cost of gas.

110.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.208.4

Societal Cost Test – Use of the Ceiling Price of Biomethane as the Avoided Cost of Gas

110.1 FEU states it is using the maximum unit price of $15.280 per GJ of pipeline-quality biomethane as a proxy cost for the purposes of determining the cost effectiveness of its programs. Please provide the annual amount of pipeline-quality biomethane injected into FEU's pipeline network as a percent of total GJ throughput.

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

In the Application in Table 4.2-1 the Companies states forecasted annual throughput of 203,914,000 GJs in 2012 and 204,214,000 GJs in 2013, while in Table J-4 the Companies forecast biomethane injection of 184,750 GJs in 2012 and 284,500 GJs in 2013. This results in a forecast of biomethane representing 0.09% of total throughput in 2012, growing by 53.8% to 0.14% of throughput in 2013.

When compared to the amount of energy savings resulting from EEC activities, however, the biomethane forecast of 284,500 GJs in 2013 is 171.4% of the 166,000 GJs of annual savings made possible by EEC activities in 2010. This is a better point of reference, particularly given the fact that the price for the energy cost avoided by EEC activities is almost certain to be different , and higher, than the average cost of energy overall, as many of the FEU's EEC programs are aimed at space heating and thus reduce peak loads.

111.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.208.6

Societal Cost Test – Use of the Ceiling Price of Biomethane as the Avoided Cost of Gas

111.1 FEU states that jurisdictions such as Ontario, the EU, China, Iran, Israel and South Africa have added higher feed-in tariffs for alternative energy such as photovoltaic and wind power. Is FEU asserting that these same jurisdictions are using photovoltaic and wind power feed-in tariffs as the proxy price for calculating avoided energy costs under the TRC methodology? Are these higher energy sources used for costs effectiveness screening?

Response:

The FEU are not asserting that the jurisdictions noted above that provide higher feed-in rates for alternative energy are also using these rates as a proxy price for calculating avoided energy costs or being used for cost effectiveness screening.

As noted in the response to BCUC IR 1.208.6, these examples were cited to support the principle that utilities both within Canada and internationally are willing to pay more for "green" sources of energy. The FEU's proposal to use the ceiling price of biomethane which is calculated off the Tier 2 electricity rate for BC Hydro as the avoided cost of gas for cost-effectiveness screening recognizes that as DSM is also a green energy source, society should be willing to pay as much for DSM as for other green energy, rather than cap the investment in DSM at the level society is willing to pay for conventional energy.

111.2 FEU cites the California definition of the Societal Cost test contained in the California Standard Practice Manual (July 2002). Specifically, FEU states that under California practices, the SCT allows for the use of higher marginal prices of avoided costs if its costs are lower than other utilities in the state or than out-of-state suppliers. Please comment on whether the avoided gas costs of regional suppliers considerably higher than the avoided gas costs incurred by FEU.

Response:

Table 1 below illustrates that the avoided natural gas costs currently being used by FEU are similar to other utilities in the region. Natural gas avoided costs for the Pacific Northwest from the Northwest Power and Conservation Council (NWPCC) Sixth Northwest Power Plan are shown in the table below, along with other avoided natural gas costs for Washington, Idaho, and Oregon from regional national utilities. Values are presented in dollars per therm.

While FEU's avoided natural gas costs are in the range of other utilities in the region, FEU's use of alternate fuels as allowed by the California Standard Practice manual is not limited to the marginal cost faced by the utility or even neighboring utilities. Rather, the Societal Cost test description states "Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources" (California Standard Practice Manual, July 2002, p19). As noted in the response to BCUC IR 2.111.1, FEU believes that the ceiling price of biomethane, which is an efficiency adjusted value calculated from BC Hydro's Tier 2 RIB rate, is the alternative resource that best reflects a "green" gaseous fuel in British Columbia.

Year	NWPCC[33]	Avista Utilities – Washington and Idaho[34]	Avista Utilities – Oregon[2]	NW Natural– Oregon[35]	FEU
2011	$0.52	$0.535	$0.548	$0.588	$0.617
2012	$0.55	$0.546	$0.559	$0.677	$0.681
2013	$0.58	$0.578	$0.590	$0.744	$0.735
2014	$0.62	$0.518	$0.531	$0.820	$0.787
2015	$0.65	$0.726	$0.740	$0.899	$0.826
2016	$0.66	$0.833	$0.848	$0.915	$0.856
2017	$0.67	$0.897	$0.915	$0.925	$0.878
2018	$0.68	$1.004	$1.022	$0.937	$0.899

33 Avoided costs for NWPCC are in 2006 dollars.

34 Avista Utilities avoided costs are in 2009 dollars. Avista Utilities report costs as 2009-2010, 2010-2011, etc. For this table, 2009-2010 is reported as 2010, 2010-2011 is reported as 2011, and so on. These are the expected annual scenario avoided costs from Avista Utilities' 2009 Natural Gas Integrated Resource Plan.

35 NW Natural also reports costs as 2009-2010, 2010-2011, etc. For this table, 2009-2010 is reported as 2010, 2010-2011 is reported as 2011, and so on. These are the base case scenario avoided costs from NW Natural's 2011 Integrated Resource Plan.

Year	NWPCC[33]	Avista Utilities – Washington and Idaho[34]	Avista Utilities – Oregon[2]	NW Natural– Oregon[35]	FEU
2019	$0.69	$1.066	$1.085	$0.921	$0.919
2020	$0.70	$1.088	$1.110	$0.907	$0.940
2021	$0.72	$1.090	$1.112	$0.914	$0.960
2022	$0.73	$1.095	$1.119	$0.940	$0.981
2023	$0.75	$1.117	$1.143	$0.947	$1.003
2024	$0.76	$1.106	$1.134	$0.954	$1.025

112.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.191.1 and 191.2

Program Details

112.1 Please compile the data in Attachments 191.1 (Program Details), 191.2a and 191.2b and complete the following table for each program.

Program Area																		
Program	Expenditures (Incentive + Non-Incentive) ($000s)			NPV Energy Savings (GJ)			Participants			Expenditures/ NPV Energy Savings ($/GJ)			Expenditures/ Participant ($/Participant)			NPV Energy Savings/Participant (GJ/Participant)		
	2009	2010	2011	2009	2010	2011	2009	2010	2011	2009	2010	2011	2009	2010	2011	2010	2010	2011

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

All of the data requested is included in the working spreadsheet provided in Attachment 112.1. For ease of formatting and because of the changing nature of the EEC portfolio, the data is shown in a slightly different format than in the example provided. The year-by-year comparisons are, however, easily conducted. Please review the 2009 and 2010 EEC Annual Reports (included as Appendices K-2 and K-3) as well as Appendix K-1, all within Exhibit B-1, for an explanation of the year over year changes to the program and portfolio information.

113.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IRs 1.192.4 and 192.4.4

Comparison to Other Utilities

113.1 Please complete the table filed in response to BCUC IR 192.4 with the 2012 DSM plans or requests for FEU, GazMetro, Manitoba Hydro and any other utilities for whom 2012 projected DSM budgets are known. Please include both proposed plans such as that of FEU, and utility DSM plans that have been approved.

Response:

Please see the table below. Note the following when reviewing this table:

- FortisBC Energy Utilities' 2010 DSM expenditure does not include high-carbon fuel switching expenditures
- The 2010 information in this table is based on public information from various sources. 2012 DSM Budget numbers were procured from one-on-one interviews with the respective utilities listed.
- All 2012 DSM Budget figures are considered to be proposed. None had been officially approved at the time these utilities were contacted.
- 2012 DSM Budget figures have been rounded to one decimal place (nearest $100,000).
- See the footnotes referenced in the 2012 DSM Budget column for more information on the explanation and sources for these budget figures.
- "n/a" = not available
- Note that a decimal error was made in the previously submitted version of this table. PSE's asset base was actually $8.81 billion in 2010 not $8.81 million.

Company Name	Utility Type	2010 EEC Costs ($ millions)	Year Started EEC	EEC Funding Treatment	Company Earns on EEC	Customer Base	EEC FTE	Total Employees	2010 Asset Base ($millions)	2010 Revenues ($millions)	% spend on EEC of Revenue	EEC Spend per Customer ($)	Annual Energy Savings (PJs)	$/ Energy Saved (GJ)	2010 Sales Volumes (PJs)	2012 Projected DSM Budget ($ millions)
FortisBC Energy Utilities	Natural gas	11.8	1991	DSM costs are treated as capital and amortized over fixed time period	Yes	948,970	15	1,443	3,124	1,516	0.78%	12.43	0.174	67.82	233.5	74.5 [1]
FortisBC Electric	Electric	3.95	1989	DSM costs are treated as capital and amortized over fixed time period.	Yes	161,019	9.4	549	975	257	1.54%	24.53	0.10	40.64	10.96	7.7 [2]
BC Hydro	Electric	134.792	late-1980s	DSM costs are treated as capital and amortized over fixed time period	Yes	1,830,985	131	5,842	18,093	3,822	3.53%	73.62	2.77	48.69	180.84	205.7 [3]
ATCO Gas	Natural Gas	1.7	2001	As O&M	No	1,057,369	18	2,185	1,421	747	0.23%	1.61	0.09	18.89	237	5.5 [4]
Union Gas	Natural gas	22.627	1997	DSM costs are recovered through a rate base	Yes	1,344,000	48.7	2,200	5,600	1,830	1.24%	16.84	3.62	6.25	1513.27	27.4 [5]
Enbridge Gas Distribution	Natural gas	25.47	1995	DSM costs are recovered through a rate base	Yes	1,900,000	26.5	1,961	3,837	2,475	1.03%	13.41	3.00	8.48	425.7	28.1 [6]
Gaz Metro	Natural gas	12.219	1999	As O&M	Yes	179,370	9	1,320	3,600	2,250	0.54%	68.12	1.22	10.04	209.26	12.3 [7]
Manitoba Hydro	Combined	20.77	1989	DSM costs are amortized over fixed time period	No	264,000	50	6,000	581	454	4.57%	78.67	1.77	11.71	151.74	13.1 [8]
SaskEnergy	Natural gas	1.07	2001	As O&M	No	352,000	9	1,100	1,600	952	0.11%	3.04	0.21	5.14	146	1.8 [9]
Pacific Gas and Electric	Combined	627.4	Mid-1970s	Public Purpose Fund	Yes	9,400,000	350	20,000	45,679	13,840	4.53%	66.74	5.12	122.65	423	483.6 [10]
Southern California Gas	Natural gas	172.4	Mid-1980s	Public Purpose Fund	Yes	20,700,000	30	7,067	7,986	3,822	4.51%	8.33	2.95	58.37	999.6	120.2 [11]
Puget Sound Energy	Combined	19.9	early 1980s	DSM costs are recovered via a rider on customer bill	Yes	1,750,000	120	2,900	8,810	3,320	0.60%	11.37	0.12	170.48	214.4	n/a [12]
Northwest Natural Gas	Natural gas	22.5	1980	DSM costs are treated as capital and amortized over fixed time period	Yes	673,997	2	1,028	2,617	791	2.84%	33.38	0.44	50.72	112	24.5 [13]

Table Footnotes:

1. Note: This number includes planned expenditures on high-carbon fuel switching programs.
2. Source: FortisBC Inc. 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan Application ~ Project No. 3698620.
3. Note: This is for BC Hydro fiscal year 2012. Source: 2008 LTAP.

4. Note: This number includes a one-time $600K research study and $1 million pilot study expenditure. Not included in this number is a $3 million capital expenditure for alternative energy projects and a $1 million capital expenditure for Atco Gas' Energy Education Mobile. Source: ATCO Gas General Rate Application - Filing 2011-2012 (December 2010).
5. Note: In addition to this funding, Union Gas is allowed to apply for an incremental 10% ($2.74 million) for low income programs and is allowed to overspend by 15% ($4.11 million) on program costs overall if they achieve 100% of their pre-authorized results. Source: Keith Boulton, Director, Energy Conservation & Residential Marketing, Union Gas Ltd.
6. Note: Same as with Union Gas, in addition to this funding, Enbridge is allowed to apply for an incremental 10% for low income programs and is allowed to overspend by 15% on program costs overall if they achieve 100% of their pre-authorized results. Source: Bill Chitata, Program Manager - Business Market Developments, Enbridge Gas Distribution Inc.
7. Source: Gaz Metro, Cause Tarifaire 2012, R-3752-2011.
8. Note: This is the DSM budget for the natural gas side only (the electricity DSM budget is $39.9 million). Also, note that Manitoba Hydro's fiscal year is April 1 to March 31. This budget applies to the 2012/13 fiscal year and is reported in 2010 dollars. Source: Cheryl Pilek, Power Smart Planning, Evaluation & Research, Manitoba Hydro.
9. Note: Includes all regular DSM program costs including marketing and advertising but does not include employee wages. Source: James Gates, Senior Engineer, Customer Technology, SaskEnergy.
10. Note: The California utilities' budgets are issued based on 3 year program cycles. Currently, they are operating in the 2010-2012 cycle (budget = $1.338 billion). The figure listed here was reached by taking the remaining budget for 2011-2012 and dividing it by 2. Also note that this figure includes EM&V but does not include low income programs. Low income programs are approved under a separate program cycle. Source: PG&E 2010 EE Annual Report.
11. Note: The California utilities' budgets are issued based on 3 year program cycles. Currently, they are operating in the 2010-2012 cycle (budget = $291.4 million). The figure listed here was reached by taking the remaining budget for 2011-2012 and dividing it by 2. Also note that this figure includes EM&V but does not include low income programs. Low income programs are approved under a separate program cycle. Source: SCG 2010 EE Annual Report.
12. Puget Sound Energy was not able to share their proposed 2012 DSM budget yet as it is still awaiting preliminary approval from their Board of Directors and stakeholder advisory group. Their 2012 DSM plan is set to be finalized by November 2011. Source: Liz Norton, Manager, Natural Gas Development and Marketing Puget Sound Energy, Puget Sound Energy.
13. Source: Holly J. Meyer, Environmental Programs Manager, Northwest Natural.

114.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.197.3

EEC Funding for Innovative Technologies

"FEU believes that the funding envelope for Innovative Technologies…should be $1.5 million for 2012 and $1.5 million for 2013 which funding will be used to undertake pilots, demonstration projects, facilitate studies, reports and EM&V. Of the $1.5 million each year, $1 million will be allocated to undertake pilots and demonstration projects and to support market-ready technology programs, $300,000 will be allocated for EM&V to confirm savings claims and guide the development of future programs that will be offered within the residential, commercial, and industrial sector, and the remaining $200,000 will be focused on reports and studies."

114.1 Please list other sources of data FEU could use for EM&V to confirm savings claims and for reports and studies to estimate energy savings and market availability.

Response:

Through a combination of informal discussions with consultants and/or other industry experts, reviewing credible studies and the Utilities' own analysis, the energy savings are estimated during program planning stages. The FEU may also consider adopting the estimated savings from other similar programs offered through different utilities and jurisdictions. Going forward, as additional data becomes available through ongoing measurement and verification processes, the FEU will refine the assumptions and update the savings in future annual reports. Please also see the response to BCUC IR 1.212 series for additional information.

114.2 Of the studies and pilots listed in the table in BCUC IR Response 198.0, which initiatives have been determined to be feasible and would be pursued as Innovative Technology programs?

Response:

The FEU would like to clarify that once the pilot and/or demonstration project has been proven to be a feasible initiative, it may fall under the Innovative Technology area, or under the Residential, Commercial or Industrial program area as appropriate.

The studies and pilots listed in the table in response to BCUC IR 1.198.0 are in different stages of the program lifecycle. The stages are categorized as program planning, program design, program launch, program evaluation and program reporting. Program planning includes gathering data through informal discussions with consultants and/or other industry experts, reviewing and/or commencing studies, investigating other programs offered by utilities and jurisdictions and the performing the Companies own analysis. Program design includes developing a program framework, controls, legal considerations, partnerships and program processes. Program launch includes developing any marketing collateral, outreach, site selection, administration associated with processing applications and day to day operations. The timing for site selection may vary from program to program depending on the required uptake numbers and participation rates. Program evaluation includes confirming the proof of system commissioning and facilitating the EM&V plan to validate energy savings claims and systems performance through either impact evaluations and/or real-time monitoring equipment. System commissioning provides the FEU with the proof that the technology has been installed and is operational. The timing on the commissioning of the system depends on the type of technology installed, permits required, and equipment availability. In the case where the FEU have partnered with an existing program that was launched through either the local, provincial or federal government, program evaluation may be limited to impact evaluations and customer satisfaction surveys. Further details on the evaluation framework can be found in response BCUC IR 1.212.2.1. Program reporting is the stage where FEU evaluates the overall results of the program to determine its feasibility. This includes having a better understanding of the potential market barriers, the level of customer awareness and acceptance, the appropriate level of incentives geared to drive adoption, the level of quality and installation and the actual energy savings associated to the measure.

Below is a list showing the different program stages and timing for each of the 2010 and 2011 Innovative Technology activities outlined in the response to BCUC IR 1.198.0.

2010 Programs	**Program Stage**	
Solar Water Heating PSECA Program	Program Evaluation - Awaiting proof of system commissioning	Expect results from impact evaluations late 2012
2011 Programs	**Program Stage**	
Solar Air Heating PSECA Program	Program Evaluation - Awaiting proof of system commissioning	Expect results from impact evaluations late 2013
SolarBC Schools Incentive Program	Program Evaluation - Awaiting proof of system commissioning	Expect results from impact evaluations late 2013
Solar Residential Hot Water - Pilot	Program Launch - Site Selection	Expect results from EM&V late 2012
City of Vancouver MURB - Pilot	Program Planning	Not Determined
City of Courtenay Solar Pool Demonstration Project	Program Evaluation - Establishing EM&V plan	Not Determined
Lumber Kiln Energy Management Controls Study	Program Evaluation - Awaiting proof of system commissioning	Expect results from the study early 2012
Occupancy Sensor Study	Program planning	Expect results from the study early 2012
Thermal Curtain Study	Program planning	Expect results from the study early 2012
Geoexchange Energy Performance Study	Program planning	Expect results from the study early 2012
Westhouse Demonstration Project	Program Evaluation - Awaiting proof of system commissioning	2013
CESIG Gas Utilization Working Group Membership	Program planning	N/A

115.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.198.5.1

EEC Funding for Innovative Technologies

"Both FortisBC Inc. (electric) and BC Hydro confirm that they are evaluating market-ready technologies and conducting pilot studies and/or demonstration projects to validate manufacturer's claims about equipment and system performance, and energy efficiency."

115.1 Please explain how FEU is collaborating with BC Hydro and FortisBC Inc to evaluate market-ready technologies, conduct pilot and demonstration studies and validate manufacturers' claims.

Response:

Evaluating market-ready technologies, conducting pilot and demonstration studies and validating manufacturers' claims is a common practice within electric utilities such as FortisBC Inc. (electric) and BC Hydro as referenced in BCUC IR 1.198.5.1. Traditionally most of the pilots and demonstration projects initiated by BC's electric utilities are focused on measures that conserve electricity. The FEU's collaboration with the electric utilities to evaluate market ready technologies, conduct pilot and demonstration studies and validate manufacturers' claims would depend on the technology in question's applicability towards the gas utility and its customers.

One example of such collaboration would be the "Advanced Control of Lumber Drying Using an Energy Management System" demonstration project initiated by BC Hydro, which is an initiative that proposes to explore both electricity and natural gas savings from this technology. The FEU have committed funds towards a study of this technology which will be used to validate both electric and gas savings. Preliminary results from the study should be completed in late 2011 or early 2012. Further details on that study can be found in response to BCUC IR 1.197.3.

116.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 201.3

EEC Accountability Mechanisms - Stakeholder Group

116.1 Please list the specific instances when the rate impact of EEC program spending and EEC funding transfers was discussed at the EEC Stakeholder group.

Response:

The rate impact of EEC program spending has not been discussed at the EEC Stakeholder group meetings to date as the meetings have largely focused on receiving input on EEC activities and programs currently in market and in development. Discussion on rate impacts, however, did come up during the FEI 2010-2011 RRA, FEVI 2010-2011 Revenue Requirements and Rate Design Application, and the FEU 2010 Long Term Resource Plan ("LTRP") Application proceedings. In the FEI 2010-2011 RRA, the response to a similar question was provided to BCUC IR 1.153.1, which discussed the probable impact on future rates on the EEC deferral account, an excerpt of which follows:

EEC Deferral Account Continuity

	2008	2009	2010	2011	2012
Opening Balance	-	510	5,420	23,222	42,466
Gross Additions	744	7,258	25,845	29,619	-
Less Taxes	(234)	(2,177)	(7,366)	(7,849)	-
Net Additions	510	5,081	18,479	21,770	-
Amortization Expense	-	(170)	(678)	(2,526)	(4,533)
Closing Balance	510	5,420	23,222	42,466	37,933
Mid Year Average	255	2,965	14,321	32,844	40,199

Incremental Cost of Service & Rate Impact of EEC Deferral Account

	2010	2011	2012
Tax Rates	28.50%	26.50%	25.00%
Equity Earned Return	2.97%	2.97%	2.97%
Return on Rate Base	7.31%	7.37%	7.37%
Income Tax Expense Calculation			
Equity Earned Return	425	974	1,192
Add: Amortization Expense	678	2,526	4,533
Taxable Income After Tax	1,103	3,500	5,725
Before Tax Income	1,542	4,762	7,633
Tax Expense	440	1,262	1,908
Cost of Service			
Amortization Expense	678	2,526	4,533
Tax Expense	440	1,262	1,908
Earned Return	1,046	2,421	2,963
Total Cost of Service Impact	2,164	6,208	9,404
Margin @ Existing Rates	528,677	531,158	531,158
Cost of Service Impact as a % of Gross Margin	0.41%	1.17%	1.77%

The approximate impact on delivery rates of the deferral of the 2008-2011 costs in Table C-3-2 is an increase of 0.41% in 2010, an increase of 1.17% in 2011 and an increase of 1.77% in 2012.

The FEVI 2010-2011 Revenue Requirements and Rate Design Application, also discussed the probable impact on future rates on the EEC deferral account which was addressed in BCUC IR 1.68.1 from that proceeding, an excerpt of which follows:

Terasen Gas Inc. ("TGVI" or the "Company") 2010-2011 Revenue Requirements and Rate Design Application	Submission Date: August 28, 2009
Response to British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1	Page 162

(000's of $)

EEC Deferral Account Continuity

	2008	2009	2010	2011	2012
Opening Balance	195	-	965	4,590	8,298
Gross Additions	-	1,379	5,204	5,683	5,683
Less Taxes	-	(414)	(1,483)	(1,506)	(1,421)
Net Additions	-	965	3,721	4,177	4,262
Amortization Expense	(195)	-	(97)	(469)	(886)
Closing Balance	-	965	4,590	8,298	11,674
Mid Year Average	98	483	2,778	6,444	9,986

Incremental Cost of Service & Rate Impact of EEC Deferral Account

	2010	2011	2012
Tax Rates	28.50%	26.50%	25.00%
Equity Earned Return	3.21%	3.21%	3.21%
Return on Rate Base	7.02%	7.25%	7.25%
Income Tax Expense Calculation			
Equity Earned Return	89	207	321
Add: Amortization Expense	97	469	886
Taxable Income After Tax	186	675	1,207
Before Tax Income	260	919	1,609
Tax Expense	74	244	402
Cost of Service			
Amortization Expense	97	469	886
Tax Expense	74	244	402
Earned Return	195	467	724
Total Cost of Service Impact	365	1,179	2,013
Margin @ Existing Rates	143,104	137,400	137,400
Cost of Service Impact as a % of Gross Margin	0.26%	0.86%	1.46%

In the LTRP, the responses to BCUC IR 1.33.1 and BCUC IR 1.51.5 with Attachment 51.5 details the rate base, customer rates, and impact of cost of service for each of the three EEC funding scenarios A, B, and C. The funding ceiling request in this current RRA is closest to Scenario C.

Attachment 116.1 contains an excerpt of the 2010 LTRP responses to BCUC IRs 1.33.1 and 1.51.5 which also contains the list of assumptions used in Attachment 51.5 of that same IR response.

The future rate impacts of the EEC funding proposed for 2012 and 2013 are being reviewed in this Revenue Requirements proceeding. Three of the registered intervenors in this Revenue Requirements proceeding - Commercial Energy Consumers, British Columbia Public Interest Advocacy Centre, and BC Sustainable Energy Association - are also part of the EEC Stakeholder group.

In addition, funding transfers occurring in 2010 were specifically discussed at the EEC Stakeholder group meetings. On November 24, 2010 and March 15, 2011, FEU did discuss the ability to transfer EEC monies between different program areas going forward. These instances can be found in the both the November 2010 presentation titled "EEC – Looking Ahead" (slide "Funding approval request – 2012 and beyond") and March 2011 presentation titled "2010 EEC Portfolio Highlights" (slide "Program Area Funding Transfer") and the November 2010 meeting minutes in Appendix H of the 2010 EEC Annual Report, filed as Appendix K-3 to Exhibit B-1. This funding transfer did not have rate impacts as overall EEC spending for 2010 was below the approved ceiling amount.

117.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.201.1

Innovative Technologies – NGV Program

117.1 In Information Response 1.201.1, FEU states that the Company is proposing to use the SCT for the purposes of screening the cost effectiveness of the NGV program with a modification to allow for the change in the benchmark ceiling price <u>from Biomethane to the marginal price of natural gas</u>. Please comment on the following:

a. Is the company aware of any other utilities that use different avoided gas costs when screening the cost effectiveness of its DSM programs? Or do other utilities only use one avoided gas cost stream for screening each and every DSM program?

<u>Response:</u>

The use of the same or different avoided costs varies by jurisdiction, utility, and program. For example, both electric and gas utilities have used avoided costs that do not vary by revenue class or end use, while other utilities have avoided costs that differ across these variables.

In the Pacific Northwest, PacifiCorp routinely uses avoided costs for cost-effectiveness calculations that differ by sector and end use, reflecting the impact of costing periods and resources associated with each. In Pennsylvania, electric distribution companies (EDCs) are required to calculate avoided costs using NYMEX prices for years 6-10. Those prices are adjusted to account for on-peak and off-peak variations and further adjusted by sector to reflect transmission rates, distribution rates, and ancillary service rates. EDCs are also permitted to use end-use profiles to properly calculate the weighted annual average avoided cost for each measure or program.

In New York, the Public Service Commission published price forecasts that apply to all utilities in the state for cost-effectiveness calculations under the Energy Efficiency Portfolio Standard (EEPS) proceedings. Avoided costs for gas utilities are distinguished by region: upstate New York and downstate New York. Similarly, electric avoided costs are distinguished by New York Independent System Operator zones and avoided capacity and distribution costs are provided for the downstate and upstate New York regions. Within specific areas of Consolidated Edison of New York's service territory, capacity constraints are a critical issue. For that reason, Con Edison's Targeted DSM program has traditionally used higher avoided capacity costs than those used for standard DSM programs in calculating cost-effectiveness.

Another common adjustment is the inclusion or exclusion of avoided distribution costs in benefits calculations. While avoided distribution costs are commonly used for residential program benefits, they are carefully considered for large commercial and industrial customers for whom these avoided costs may not exist.

b. Is the company aware of any other utilities that use a higher avoided gas costs for the purposes of screening conventional energy efficiency programs compared to the avoided gas costs used for screening fuel-switching or load-building programs

Response:

As described in the response to BCUC IR 1.17.1.a, there are instances where different avoided costs are used for screening different programs.

Research conducted by the Cadmus Group Inc. (a consultant retained by the Companies) indicates that the only type of NGV fuel switching programs are national, provincial, and local alternate-vehicle policies and programs in North America where the economics appear to be based on a variant of the participant test that includes, at least implicitly, greenhouse gas reduction benefits. The following studies provide useful analysis and information in this regard:

- Will Natural Gas Vehicles Be In Our Future?, Alan J. Krupnick, Resources for the Future ("RFF"). 2011.
- Technology Improvement Pathways to Cost-Effective Vehicle Electrification, Aaron Brooker et al., National Renewable Energy Laboratory ("NREL"). 2010.
- Seeing past the hype: why Natural Gas Vehicles (NGVs) may be more cost effective than Electric Vehicles (EVs) for fighting climate change, A.J. Goulding et al., London Economics ("LE"). 2011.

In the RFF report, the author examines the payback period of NGVs under a broad set of scenarios. The cost-effectiveness of these vehicles, the paper contends, vary based on a set of inputs that includes the retail price difference of natural gas and diesel, the fuel economy of NGVs, vehicle miles traveled, and the price differential of the vehicle itself. To summarize, the fuel costs in this study are based on retail fuel prices.

NREL's report offers an outlook of EV cost-effectiveness, comparing the full cost of electric and hybrid vehicles under several scenarios of technological progress. The analysis looks at lifetime costs of standard, hybrid, and electric vehicles over 15 years, and apportions costs into vehicle costs (excluding battery), battery costs, and fuel (both gasoline and electricity) costs. For fuel costs, the authors apply costs of $0.10/kWh and $3.21/gallon of gasoline. These costs are sourced from International Energy Agency statistics and represent average customer retail prices of electricity and gasoline, respectively.

The LE report provides the comparative cost achieving GHG reduction goals though NGV and EV programs. In the analysis, LE uses average retail fuel costs available from the Energy Information Administration. LE finds the high initial cost of EVs to be a major liability, and reports that, although they still rely on fossil fuels, NGVs are the more cost-effective emissions reduction mechanism. Over the ownership period (5 years) of the vehicle, both NGVs and EVs have a higher annual cost than conventional vehicles, with the EV incremental cost being significantly higher than NGV incremental cost. This substantial difference leads the authors to conclude that NGVs are the more cost-effective method of achieving GHG savings, despite EVs' lower emissions.

All three studies attempt to measure the cost-effectiveness of alternate-fuel vehicles in the context of a cost comparison with conventional vehicles that uses retail fuel prices. Furthermore, national and regional policy makers are relying on studies such as these in developing new transportation policies and subsidies. Consistency with those policies is best served by an apples-to-apples comparison of diesel fuel and natural gas within the Societal test but with a substitution of natural gas costs for biomethane costs.

In the U.S., the American Recovery and Reinvestment Act of 2009 (ARRA) and the Department of Energy (DOE) have funded NGV stations and vehicles in 21 states. The entities receiving the funding for NGV do not appear to have demonstrated the cost-effectiveness of these programs prior to implementation. It is also important to note that the DOE and ARRA funding often require receiving matching funds from state and local government. These programs are typically geared toward energy independence, economic development, and greenhouse gas emissions reflecting national and regional public policy.

c. Is the company aware of any utilities that require natural gas customers to pay for programs that benefit diesel/oil companies?

Response:

There is a faulty premise in the question that the FEU's NGV initiatives might somehow benefit diesel/oil companies. The FEU's NGV initiatives do not benefit diesel/oil companies but rather have the potential to provide significant benefits to natural gas ratepayers as the NGV programs grow. The FEU are not aware of any utilities that require natural gas customers to pay for programs that benefit diesel/oil companies. The purpose of the FEU NGV program is to encourage customers to switch <u>away</u> from higher-carbon diesel fuel <u>to</u> lower-carbon natural gas fuel. It is the view of the Companies that this high-carbon fuel switching activity would, if anything, disadvantage diesel/oil companies rather than benefitting them.

Substantial benefits from the NGV program accrue over time to all customers in the form of reduced delivery rates (all else equal) due to an increase in system throughput. As natural gas throughput falls due to customers increasingly moving to lower carbon and lower GHG emitting energy sources and the impacts of EEC programs which seek to reduce energy demand, the NGV program increases it, counteracting the overall impact of declining throughput on ratepayers.

d. Please explain the policy rationale for natural gas customers to subsidize diesel/oil consumption companies.

Response:

The FEU note that the wording in BCUC IR 2.117.1c refers to diesel/oil companies while the wording in the current IR, BCUC IR 2.117.1d, refers to diesel/oil consumption companies. If the current IR is intended to pertain to the same types of companies as BCUC IR 2.117.1c then natural gas customers are not and will not be subsidizing diesel/oil companies under any of the proposals of the FEU. Please see also the response to BCUC IR 2.117.1c.

If the reference in the question is to companies that consume oil and diesel fuel in carrying out their business (i.e. fleet vehicle operators in the case of NGV), the FEU's EEC programs do not discriminate between customers that meet the program eligibility criteria. EEC programs are open to any qualifying customers regardless of the customer's previous energy source, and all EEC expenditures are recovered from all customers, thus non-participating customers in the Companies' EEC programs, in effect, subsidize (i.e. provide funding for) participating customers. Similar subsidies from non-participants to participants already exist for the FEU's previously approved fuel switching EEC programs, such as the programs to switch homes or businesses from heating oil or propane to higher efficiency natural gas equipment.

The FEU are presently analyzing the effects of the Commission's recent decision on the use of EEC Funding for NGV Incentives (BCUC Order No. G-145-11 dated August 15, 2011). The Decision states that the Companies did not have approval to use EEC funds to provide incentives for NGVs. The Decision also notes that additional submissions and regulatory process are necessary to deal with the prudence of EEC incentives that have already been granted for NGV. The FEU's rationale for providing incentives to NGV were discussed in detail in the FEU's Application for CNG and LNG Service and covered again in summary in Section 1.2.3.2 of this Application (Exhibit B-1, pages 13-14).

e. If the Company's NGV program is approved, does FEU expect the benefits of the NGV financial incentives to flow through to end users/customers of the transportation companies receiving the financial incentives? If so, how will FEU ensure such customer benefits?

Response:

As the transportation industry is highly competitive, the FEU expect the benefits of NGV financial incentives made to the owners of vehicle fleets to flow through to the end use customers that make use of the services that NGV fleet owners provide. For example, if a NGV fleet of garbage trucks is providing service to a customer, the FEU would expect the costs of the service paid by the customer to come down over time since the NGV fleet owner faces competition from other service providers and is therefore likely to use its reduced operating costs to retain its customer and get new business.

The specific circumstances associated with each incentive award will vary, therefore it would be impractical for the FEU to attempt to monitor or validate the degree to which this occurs in all scenarios. Operating cost and margin information is privately held by each individual fleet company but transportation businesses in general are well known to be very competitive with little potential for excess profits.

118.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 212.2.1

Program Evaluation

118.1 Please confirm that FEU has no EEC evaluation schedule including process and impact evaluations for its programs. If this is not true, please provide the schedule.

Response:

The FEU do have an evaluation schedule including process and impact evaluations for its current and planned programs. Attachment 118.1 includes an example of a completed study and evaluation of energy savings from the Efficient Boiler Program.

The table below provides a list of programs currently planned for evaluation for the end of 2011 and 2012. This evaluation schedule represents a snapshot of current evaluation plans for established programs that the FEU believe will reach a certain level of maturity by end of 2012 in order to obtain meaningful results. As the FEU deliver more programs into the market place and as additional data becomes available for existing programs, the FEU will refine this schedule. Additionally the Companies in their 2011 staffing plans have identified the need for a Program Manager responsible for evaluation, measurement and verification (EM&V) of programs to put a formal structure, evaluation framework and update process in place to support EEC programming.

The schedule does not include pilot programs or demonstration projects at this time as related EM&V activities for such programs remain under development and will continue to evolve under the direction of yet to be hired EM&V Manager. For such types of programs the FEU rely on real-time monitoring equipment such as sensors and data loggers to better evaluate real-time data of equipment performance and energy savings. These latter EM&V approaches require a greater allocation of the overall budget towards evaluation since these systems require additional resources and costs in installing the monitoring equipment, gathering the data, analyzing the data and reporting on that data. As EM&V program manager begins to gather more market intelligence on best practices for monitoring & evaluating innovative technologies, FEU would analyze and incorporate the findings into its evaluation plan and report during scheduled EEC stakeholder meetings or the forthcoming Annual Report.

Please also refer to the response to BCUC IR 1.212.2.1 for additional information on the evaluation framework.

FEU Evaluation schedule for 2011 and 2012.

Progam Area	Territory	Type of evaluation	Evaluation Name	Years the program has been running	Evaluation lead	Evaluation partnership	proposed budget	Proposed timelines
Residential	FEI & FEVI	Process	Ener Choice fireplace program awareness and dealer feedback	3	FEU	none	$25,000	Complete - waiting for the final research paper to be produced.
Residential	FEI & FEVI	impact & process	Ener Choice fireplace program consumption analysis	3	FEU	none	$50,000	February 2012 - start
Residential	FEI & FEVI	Process	0.62EF Water Heater Program	1	FEU	none	$12,000	August 2011 start
Residential	FEI & FEVI	impact & process	TLC participant feedback and Determination of Energy Savings	2	FEU	none	$25,000	January 2012 - start
Residential	FEI & FEVI	Process	EG80 New Construction Program - builder feedback	0	FEU	BCHydro	$10,000	August 2011 start
Residential	FEI & FEVI	Process	New Construction Program - Non- Energy Benefit Analysis	0	FEU	BCHydro	$25,000	August 2011 start
Joint Iniatiatives	FEI & FEVI	impact & process	LiveSmart BC program evaluation	3.5	BCHydro	BCHydro, FEU, FBC and MEM	$50,000	August 2011 start
Joint Iniatiatives	FEI & FEVI	impact & process	Hot 2000 - Field Verification and Consumption Analysis	3.5	BCHydro	BCHydro, FEU, FBC, NRCan and MEM	$40,000	April 2011 start
Enabling	FEI & FEVI	Process	Energy Specialist Pilot Program Evaluation Brief	1	FEU	none	none	August 2011 start
Commercial	FEI	Impact & process	Energy Assesment Program	10	FEU	none	$18,000	5/25/2010- completion
Commercial	FEI & FEVI	Impact & process	Efficient Boiler program feedback & Anaylsis	6	FEU	none	$50,000	Complete - waiting for the final research paper to be produced.
Commercial	FEI & FEVI	Impact	Efficient Commercial Water Heater Program - Metering project	1	FEU	none	$50,000	Dec-2012- completion
Commercial	FEI & FEVI	Impact	Fireplace Timers Pilot Program	2	FEU	none	$40,000	Aug 2012- completion
Conservation for Affordable Housing	FEI & FEVI	Process	Energy Savings Kits	1	BC Hydro	BC Hydro	$20,000	Dec 2012- completion
Conservation Education and Outreach	FEI & FEVI	Process	Bill Insert and Bill Messaging	ongoing	FEU	none	$45,000	Feb 2011- completion
Conservation Education and Outreach	FEI & FEVI	Process	Event Tracking	5	FEU	none	$15,000	Dec 2012- completion
Conservation Education and Outreach	FEI & FEVI	Process	Long Term Tracking	ongoing	FEU	none	$45,000	Dec 2011- completion
Conservation Education and Outreach	FEI	Process	Destination Conservaton for Public Buildings Pilot	1	FEU	FortisBC Inc.	$5,000	March 2012 completion

119.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 215.4.1 and 2008 EEC Proceeding Exhibit B-5, Response to

BC Hydro IR 11.3

Attribution of Savings

"11.3 In the scenario depicted in 11.2 [in which the co-funding from each of two partners is critical to the municipal program], would it be reasonable to attribute 100 per cent of the program savings to each partner?

Response:

It is possible that it would be reasonable to attribute 100 per cent of the program savings to each partner, however, in the absence of a more concrete scenario, the Companies would prefer not to comment definitively on the reasonable attribution of savings."

119.1 Does FEU follow this attribution rule for all EEC programs (in co-funded programs 100% of the electricity savings are attributed to the electric utility and 100% of the gas savings are attributed to the gas utility; and where the co-funding is deemed critical to the program, each funding partner claims 100% of the savings)?

Response:

The FEU do not follow any defined attribution rule. Since the 2008 EEC Proceeding, the Companies' approach to attribution is on a case-by-case basis. The Companies have not encountered any scenarios where funding partners have all claimed 100% of the savings. In joint programs with government and with electric utilities, the FEU claim the natural gas savings and the electric utility claims the electric savings. For example in the energy savings kit and spray valve program, the FEU's claim the gas savings while BC Hydro claims the electricity savings.

119.1.1 If so, does this rule not allow for double counting of savings?

Response:

Please see the response to BCUC IR 2.119.1.

119.1.1.1 Are there programs that are currently running where this attribution rule is applied?

Response:

Please see the response to BCUC IR 2.119.1.

120.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 1.211.1

Conservation Potential Review Summary Report

120.1 Please show the benefit to cost ratios of the measures screened for the conservation potential study that did not pass the TRC under the following scenarios:

a. 3% discount rate, No Adder, Traditional Cost of Gas
b. 3% discount rate, 10% Adder, Traditional Cost of Gas
c. 3% discount rate, 20% Adder, Traditional Cost of Gas
d. 3% discount rate, 30% Adder , Traditional Cost of Gas
e. 4% discount rate, No Adder, Traditional Cost of Gas
f. 4% discount rate, 10% Adder, Traditional Cost of Gas
g. 4% discount rate, 20% Adder, Traditional Cost of Gas
h. 4% discount rate, 30% Adder , Traditional Cost of Gas
i. 5% discount rate, No Adder, Traditional Cost of Gas
j. 5% discount rate, 10% Adder, Traditional Cost of Gas
k. 5% discount rate, 20% Adder, Traditional Cost of Gas
l. 5% discount rate, 30% Adder , Traditional Cost of Gas
m. 7.15% discount rate, No Adder, Traditional Cost of Gas
n. 7.15% discount rate, 10% Adder, Traditional Cost of Gas
o. 7.15% discount rate, 20% Adder, Traditional Cost of Gas
p. 7.15% discount rate, 30% Adder , Traditional Cost of Gas

Response:

In the original IR set issued by the Commission, questions 120.1(i) to (l) were numbered in duplicate, therefore, the Companies have renumbered those sequentially as 120.1(m) to (p). Please see the response to BCUC IR 2.120.2.

120.2 Please show the benefit to cost ratios of the measures screened for the conservation potential study that did not pass the TRC under scenarios a. to l. above but using the Biomethane Cost of Gas.

Response:

A response to the questions as posed in BCUC IR 2.120.1 and 2.120.2 would result in thousands of output numbers, would cost tens of thousands of dollars and would take at least two months. It would require re-running the Conservation Potential Review, a study that took 9 months (September 2010 to June 2011) to complete at a cost of $520,000 plus HST.

In an attempt to respond to the question, the consultants that undertook the Conservation Potential Review, Marbek Resource Consultants, recommended instead a streamlined approach, with a view to identifying the impact trends that would result from the revised economic screening criteria set out in the Information Requests 2.120.1 and 2.120.2. This approach is discussed below.

Selected residential sector measures were used as an example. A 7.38% discount rate was added to the analysis as this was the rate used in the Conservation Potential Review, and allows the factors provided in this response to be applied to the benefit/cost ratios provided in that document. The impact trends provided below apply to all sectors.

It should be noted that the impact of these variables on the benefit/cost ratios is affected by measure life. Measures with a range of useful lives were selected to show these impacts.

The results are shown in Figures 1, 2 and 3. Highlights are noted below.

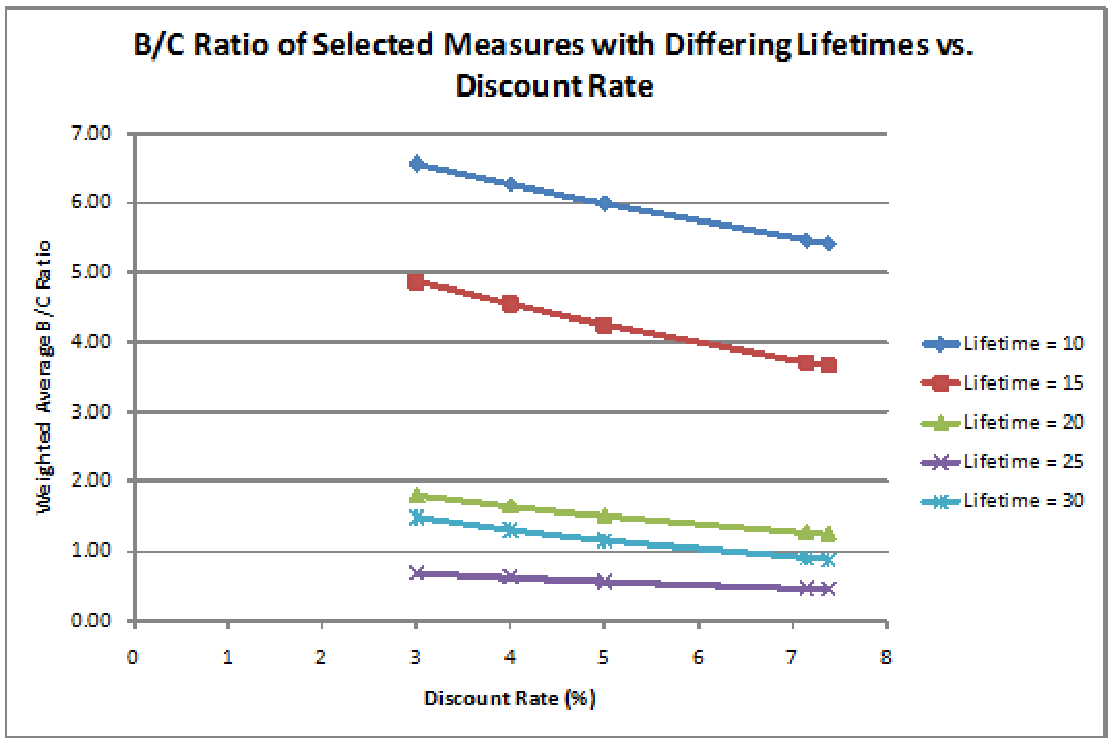
Impact of Changes to Discount Rate (Figure 1):

The impact of lower discount rates increases with longer measure life. The longer the measure life, the greater the positive impact of lower discount rates.

As illustrated in Figure 1, changing the discount rate from 7.38% to 3% improves the measure benefit/cost ratio by 69% for a measure with a 30 year lifetime and by 21% for a measure with a 10 year lifetime. For the same measures, the benefit/cost ratio improves by 48% and 15.6%, respectively, when a 4% discount rate is used instead of the 7.38%.

Figure 1: Impact of Discount Rates on B/C Ratio for Measures with Differing Lifetimes

Measure Name	Discount rate (%)	Weighted Average B/C Ratio versus Discount Rate					Percent Change vs Base Case				
		7.38	7.15	5	4	3	7.38	7.15	5	4	3
et Aerators	Lifetime = 10	5.42	5.47	5.99	6.26	6.56	0.0%	1.0%	10.6%	15.6%	2
Efficiency Gas Fireplaces	Lifetime = 15	3.67	3.72	4.26	4.55	4.87	0.0%	1.4%	16.1%	24.1%	3
Pool Heaters	Lifetime = 20	1.25	1.27	1.51	1.65	1.81	0.0%	1.8%	21.3%	32.4%	4
ssional Air Sealing/Weather Stripping/Caulking	Lifetime = 25	0.46	0.47	0.57	0.62	0.68	0.0%	1.9%	22.6%	34.3%	4
Insulation	Lifetime = 30	0.88	0.90	1.15	1.30	1.49	0.0%	2.4%	30.7%	48.0%	6



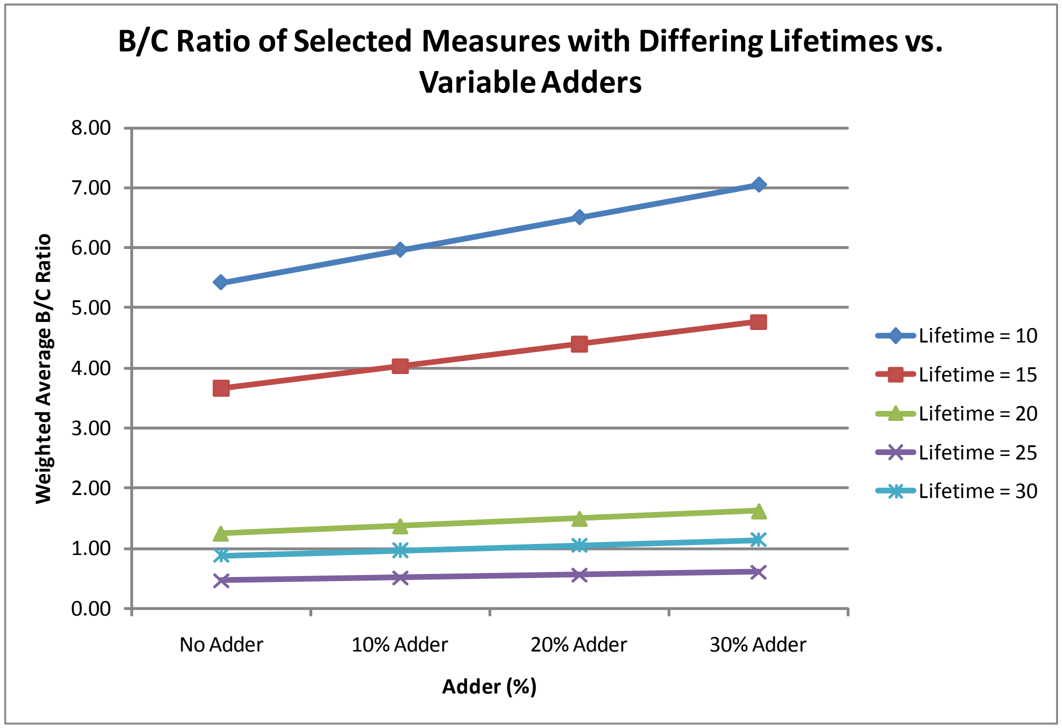
Impact of Changes to Adder (Figure 2):

The addition of a deemed adder to the avoided supply cost improves the benefit/cost ratio in direct proportion to the percentage size of the adder.

As illustrated in Figure 2, the addition of a 30% deemed adder improves the measure benefit/cost ratio by 30% for all measures, regardless of measure life.

Figure 2: Impact of Variable Adders (%) on B/C Ratio for Measures with Differing Lifetimes

Measure Name	Adder	No Adder	10% Adder	20% Adder	30% Adder	Percent Change vs Base Case: No Adder	10% Adder	20% Adder	30% Adder
		Weighted Average B/C Ratio versus Variable Adders							
Faucet Aerators	Lifetime = 10	5.42	5.96	6.50	7.04	0.0%	10.0%	20.0%	30.0%
High-Efficiency Gas Fireplaces	Lifetime = 15	3.67	4.03	4.40	4.76	0.0%	10.0%	20.0%	30.0%
Solar Pool Heaters	Lifetime = 20	1.25	1.37	1.50	1.62	0.0%	10.0%	20.0%	30.0%
Professional Air Sealing/Weather Stripping/Caulking	Lifetime = 25	0.46	0.51	0.56	0.60	0.0%	10.0%	20.0%	30.0%
Attic Insulation	Lifetime = 30	0.88	0.97	1.06	1.14	0.0%	10.0%	20.0%	30.0%



Impact of Use of Biomethane Cost of Gas (Figure 3):

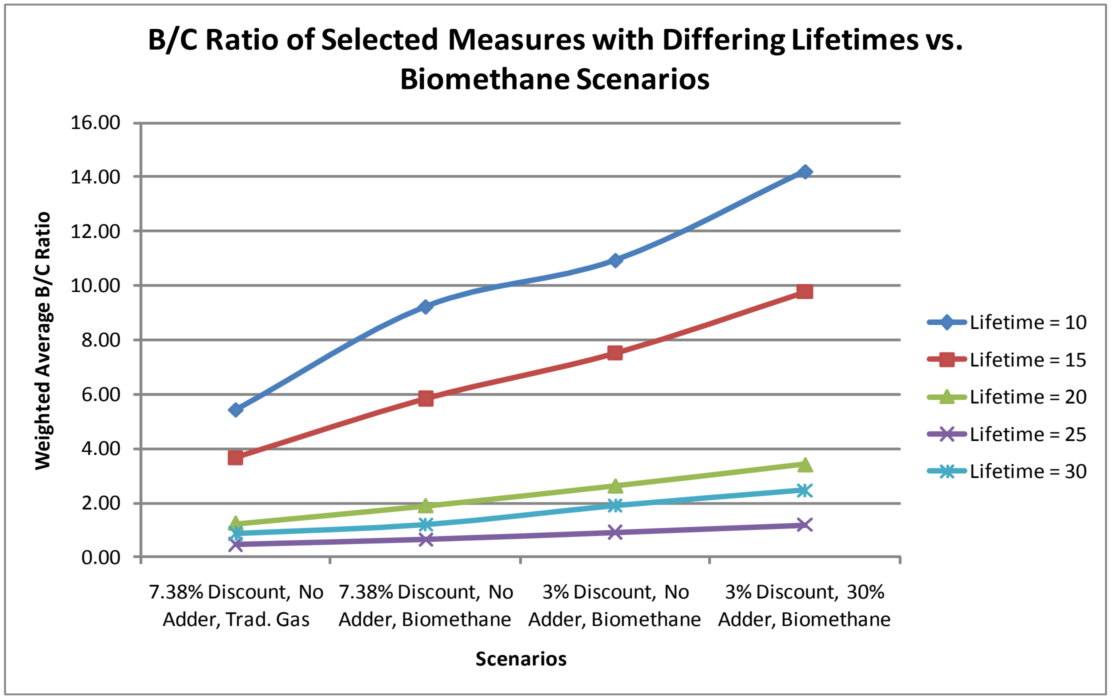
Use of the biomethane cost of gas improves the benefit/cost ratio for all measures in all scenarios. The positive impact is greater for longer life measures and when using the lower discount rate. This is because the benefits accrue for a longer period and the value of the future savings is discounted to a lesser extent when using the lower discount rate.

As illustrated in Figure 3, when a discount rate of 3% is applied together with a 30% adder, use of the biomethane cost of gas improves the measure B/C ratio by 180% for a measure with a 25 year lifetime and by 162% for a measure with a 10 year lifetime.

Figure 3: Impact of Biomethane Cost of Gas on B/C Ratio for Measures with Differing Lifetimes & Discount Rates

Measure Name	Discount Rate	Weighted Average B/C Ratio versus Biomethane: 7.38% Discount, No Adder, Trad. Gas	7.38% Discount, No Adder, Biomethane	3% Discount, No Adder, Biomethane	3% Discount, 30% Adder, Biomethane
Faucet Aerators	Lifetime = 10	5.42	9.22	10.93	14.21
High-Efficiency Gas Fireplaces	Lifetime = 15	3.67	5.83	7.51	9.77
Solar Pool Heaters	Lifetime = 20	1.25	1.90	2.63	3.42
Professional Air Sealing/Weather Stripping/Caulking	Lifetime = 25	0.46	0.66	0.92	1.20
Attic Insulation	Lifetime = 30	0.88	1.20	1.90	2.46

Percent Change vs Base Case: 7.38% Discount, No Adder, Trad. Gas	7.38% Discount, No Adder, Biomethane	3% Discount, No Adder, Biomethane	3% Discount, 30% Adder, Biomethane
0.0%	70.2%	101.8%	162.3%
0.0%	59.2%	105.0%	166.4%
0.0%	52.1%	110.9%	174.2%
0.0%	41.9%	98.3%	157.8%
0.0%	36.9%	115.5%	180.1%



Combined impact of varying parameters:
The following table summarizes the impact on a TRC from varying the parameters relative to the base analysis in the CPR using a 7.38% discount rate. These factors can be applied to the benefit/cost ratios from the Conservation Potential Review to determine which failed measures would likely pass the TRC / SCT if the FEU's proposed changes were accepted in whole or in part. The results of the economic screening can be found in Exhibit 21 on page 35 of the Residential CPR, in Exhibit 23 on page 41 of the Commercial CPR, and in Exhibit 26 on page 33 of the Industrial CPR; the CPR was filed as Attachment 196.1 to the FEU's Response to BCUC IR 196.1.

B/C Ratio Impact Relative to CPR Base Case

Measure Life	3% Discount Rate	30% Adder & 7.38% Discount	Biomethane & 7.38% Discount	Biomethane & 3% Discount	Biomethane 30% Adder 3% Discount
10 years	+ 21%	+ 30%	+ 70%	+102%	+ 162%
15 years	+ 33%	+ 30%	+ 59%	+ 103%	+ 166%
20 years	+ 45%	+ 30%	+ 52%	+ 118%	+ 174%
25 years	+ 48%	+ 30%	+ 42%	+ 80%	+ 158%
30 years	+ 69%	+ 30%	+ 37%	+ 111%	+ 180%

120.3 Please estimate the total EEC spend that would be cost effective (include all programs from the Conservation Potential Review that achieve a benefit to cost ratio of 1 or greater under the specified conditions) with the following conditions:

a. 3% discount rate, 30% Adder, Biomethane Cost of Gas
b. 3% discount rate, No Adder, Biomethane Cost of Gas
c. 3% discount rate, 30% Adder, Traditional Cost of Gas
d. 7.15% discount rate, No Adder, Traditional Cost of Gas

Response:

This information is not available as the analysis has not been developed. It is important to note that a Conservation Potential Review is different from an EEC plan with associated expenditures. Estimates of EEC spends are built from the "bottom up" and are based on summing program expenditures for all programs considered to be viable over the time frame for the EEC spend. The economic analysis done for a Conservation Potential Review is just the starting point for identifying measures that have promise as the basis for EEC programs; an EEC program contains not only incentive amounts but also non-incentive expenditures such as communication costs, program administration costs and evaluation costs, amongst others. EEC programs are then combined to create an EEC Plan with an associated EEC budget or "spend". A full response to this Information Request would require re-running a significant portion of the Conservation Potential Review in order to determine which measures that previously failed the economic test now pass the test using the parameters outlined in the Information Request. Once this work is completed, then it is necessary to develop "prototype" programs to assess key "spend" parameters such as program uptake rates, incentive levels, administration and program management and evaluation costs. This would then feed up into an EEC plan, with an associated spend. The Companies estimate that this work, and the work required to respond to BCUC IR 2.120.3(b) and BCUC IR 2.120.3(c) would take about six months, and would require significant resources.

That said, the existing core programs that the FEU are currently running under the TRC are cost-effective when considered from the perspective of the overall portfolio. The FEU have proposed the changes outlined in BCUC IR 2.120.3(a) in order to more closely align the treatment of the benefits of natural gas DSM with the intergenerational, non-energy benefits and environmental attributes of natural gas DSM. Adopting the changes that FEU have proposed would have the effect of making some of the measures that fail the economic screen used in the CPR, which was the TRC, cost-effective as they would pass the cost-effectiveness screen using the inputs in the Information Request above. This in turn would mean that more measures would be included in more programs and would provide more energy savings and be accessed by more customers, with a concurrent requirement for a higher EEC spend than would exist using the TRC as the cost-effectiveness screen.

121.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 216.3

CEO Programs

"To date, the Companies have executed few print and online advertising campaigns, including bill insert communications, and have expanded outreach and engagement activities; however, the FEU are still not able to reach all the customers the same way a mass media campaign would."

121.1 In June 2011 Mediaplanet published an Independent Section to the Vancouver Sun newspaper titled Clean Energy: Powering Your Future. Please confirm whether FEU contributed any EEC or other funds to this Independent Section for any purpose. If so, how much did FEU contribute?

Response:

Yes, the FEU did contribute funds to the Independent Section to the Vancouver Sun newspaper. The total cost of a half page colour advertisement was $15,640, with EEC contributing to one third of the cost ($5,213.30), with other FEU departments contributing to the other two thirds. The size of the advertisement was upgraded to a full page at no additional cost to the FEU, because the publication was delayed by one week. Please see also the response to BCUC IR 2.121.2, which details the Companies' EEC-related non-program media activity.

121.2 Please list the specific print and online advertising campaigns FEU has executed in 2010 and 2011. Please include the subject matter, dates and location published, and the cost.

Response:

In order to properly address the question, the Companies would like to clarify that the FEU have executed few print and online advertising campaigns, including bill insert communications, regarding EEC messages, with cost contributions specifically from the CEO program area. CEO messages pertain to general energy conservation information. The tables following list the specific print and online advertising campaigns and one-off advertisements to which CEO has contributed funds in 2010, and from January 2011 to June 2011. At this time, the CEO program area has not committed to any mass print and advertising campaigns for the remainder of 2011. The tables do not list the print and online advertising campaigns paid wholly by other EEC program areas (e.g. Residential) because that amount is captured under the specific program costs, or paid by other departments within the FEU (e.g. Community Relations, Safety, etc.). Print and online advertisements that are included as part of a larger partnership agreement and package under the CEO program area are also not included.

For some campaigns and advertisements, where appropriate and dependent on the message, the costs may be split between CEO funds and other EEC programs areas, other departments within FEU, or with external partners. The tables detail CEO's cost contributions along with other contributing partners. The rationale behind the cost splits is to ensure cost efficiencies with CEO funds, and maximize message delivery channels for EEC related communication, for instance, combining information on conservation behaviour change and a rebate on high efficient equipment. The 2010 total of CEO costs for print and online advertising is approximately 12 percent of the total 2010 CEO expenditures, demonstrating that the CEO program area to date has relied minimally on print and online advertising to educate customers.

In summary, CEO funded advertisements to educate residential customers on energy conservation during the heating season (when natural gas bills are their highest), supported the regional Canadian Home Builders' Associations by advertising in their publications and membership directories, advertised in special "green" publications, targeted Commercial customer publications, and customer bill inserts.

2010 CEO Cost Contributions - Print and Online Advertising

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Vancouver Sun - Heating Season print and online campaign						
Vancouver Sun	Draftproofing and furnace maintenance	October 15	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Programmable thermostats and rebate programs	October 22	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Energy Star furnaces	October 29	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Home energy assessments	November 5	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Weatherstripping and insulation	November 12	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Enerchoice rating and fireplaces	November 19	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Choosing a heating contractor	November 26	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Energy Efficient hot water heaters	December 3	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Energy Star and Energuide ratings	December 10	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Vancouver Sun	High efficient furnaces and hot water heaters	December 17	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Energy saving tips	December 31	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Blackpress Community Newspapers - Heating Season print and online campaign						
Blackpress - various community newspapers	Space and hot water energy usage and rebate programs	October 10 - 17	FEI - Okanagan	$8,222	EEC - Residential	$10,500
Blackpress - various community newspapers	Energy conservation tips	October 25 - 31	FEU - Lower Mainland, Northern, Interior, and Vancouver Island	$15,278	None	$15,278
Blackpress - various community newspapers	Conservation tips and high efficiency hot water heater program	November 3 - 14	FEU - Lower Mainland, Northern, Interior, and Vancouver Island	$12,543	EEC - Residential	$25,087
Blackpress - various community newspapers	Conservation tips and EnerChoice fireplace program	November 10 - 14	FEU - Lower Mainland, Northern, Interior, and Vancouver Island	$8,427	EEC - Residential	$16,856
Blackpress - various community newspapers	Space and water heating energy usage and Switch 'n' Shrink program	November 10 - 12	FEVI	$1,866	EEC - Residential	$3,732

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Blackpress - various community newspapers	Conservation tips	November 22 - 28	FEU - Lower Mainland, Northern, Interior, and Vancouver Island	$10,695	EEC - Residential	$15,212
Blackpress - various community websites	General energy conservation	November to December	FEU - Lower Mainland, Northern, Interior, and Vancouver Island	$2,600	none	$2,600
Nanaimo Bulletin – newspaper	Support home show	September	FEVI - Nanaimo	$600	None	$600
Kamloops This Week	Visit us at the Kamloops home show for energy conservation tips	March 24	FEI - Okanagan	$995	None	$995
Blackpress Kamloops This Week- online	CHBA CI Home Show	March	FEI - Interior	$99	None	$99
Canadian Home Builders' Association's (CHBA) - print						
CHBA BC - BC Homes magazine	Saving energy and environmental benefits	February and March	FEU	$1,965	None	$1,965
CHBA BC - BC Homes magazine	Congratulations of 2009 Georgies Award winners	April and May	FEU	$1,965	None	$1,965

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
CHBA BC - BC Homes magazine	Energy efficient natural gas appliances in residential construction	June and July	FEU	$1,966	None	$1,965
CHBA BC - BC Homes magazine	Energy efficient natural gas appliances in residential construction	August and September	FEU	$1,965	None	$1,965
CHBA BC - BC Homes magazine	Congratulations of Built Green Awards winners	October and November	FEU	$1,965	None	$1,965
CHBA South Okanagan - Directory	Energy efficient natural gas appliances in residential construction	April	FEI - South Okanagan	$500	None	$500
CHBA Northern BC - Directory	Energy efficient natural gas appliances in residential construction	November	FEI - Northern BC	$900	None	$900
CHBA Central Vancouver Island – Directory	Energy efficient natural gas appliances in residential construction	January	FEVI - Central Vancouver Island	$550	None	$550
CHBA Victoria – Directory	energy efficient natural gas appliances in residential construction	February	FEVI - Victoria	$1,275	None	$1,275
Residential Audience One-off						
Okanagan Home magazine	Energy efficieny in residential construction	February and March	FEI - Okanagan	$1,300	None	$1,300

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
BC Home (Canada Wide)	EnerChoice gas fireplaces	February	FEU	$3,150	None	$3,150
Pulse Group - Castanet newspapers	Energy conservation tips for homes	August and September	FEI - Kelowna	$2,457	City of Kelowna co-op	$2,457
Pulse Group- Bus Advertisement	energy conservation programs - general	October	FEI - Kelowna	$1,543	City of Kelowna co-op	$1,543
Western Living	support CHBA Victoria CARE Award winners	December	FEVI	$1,455	None	$1,455
Prosper Media - Niche Magazine	Energy efficiency in residential construction	September- to November	FEI - Okanagan	$1,438	FortisBC Inc.	$2,875
Commercial Audience One-off						
Rental Owners and Managers Society of BC – directory	Support outreach and multi-family energy conservation	October	FEU	$295	None	$295
Green Space	Energy efficiency and corporate sustainability initiatives	May	FEU	$2,785	Other FEU departments	$5,570
Office Space	Supporting Commercial conservation rebates	2010	FEU	$2,500	None	$2,500
Bill Inserts						
Residential bill insert	Conservation tips, space and hot water energy usage, outreach event	August	FEU	$16,695	None	$16,695

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Residential bill insert	Winter conservation tips, school presentations, and outreach events	December	FEU	$23,122	None	$23,122
			TOTAL	**$175,116**		**$252,971**
			TOTAL 2010 CEO PROGRAM AREA EXPENDITURES	**$1,616,000**		

2011 (January-June) CEO Cost Contributions - Print and Online Advertising

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Vancouver Sun - Heating Season print and online campaign						
Vancouver Sun	Energy Star heating systems	January 7	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Maintenance and efficiency of HVAC systems	January 14	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Home efficiency measures	January 21	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Vancouver Sun	Energy star heating systems and heating calculations	January 28	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Right sized home heating systems	February 4	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Space heating and programmable thermostats	February 11	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	R2000 insulation and proper insulation	February 18	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	Solar thermal residential applications	February 25	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Vancouver Sun	BC Spring and Garden Home Show and rebate programs	March 4	FEI - Lower Mainland	$4,000	National Energy Equipment	$8,000
Media Planet - Sustainability Report	Energy conservation as part of corporate sustainability initiatives	March	FEI - Lower Mainland	$6,963	Other FEU department	$21,760
Media Planet - Energy Report	Energy conservation as part of corporate sustainability initiatives	June	FEI - Lower Mainland	$5,213	Other FEU department	$15,640

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Blackpress Community Newspapers - Heating Season print and online campaign						
Blackpress - various community newspapers	Conservation education and Energy Saving Kit	January 11 - 21	FEI	$5,363	EEC - Conservation for Affordable Housing	$10,726
Blackpress - various community newspapers	Conservation education and Energy Saving Kit	January 26 - 28	FEVI	$1,642	EEC - Conservation for Affordable Housing	$3,731
Blackpress - RenoNation special print insert						
RenoNation - various community newspapers	High efficient appliances and space and hot water energy usage	April	FEI - Lower Mainland	$4,500	Other FEU department	$9,000
RenoNation - various community newspapers	Promoting the benfits of high efficiency natural gas appliances - focusing on Quadra Homes Development	May	FEI - Lower Mainland	$2,511	EEC - Residential and Other FEU department	$8,370
CHBA						
CHBA BC - BC Homes magazine	Energy Efficiency in residential construction.	Dec 2010 - Jan 2011	FEU	$1,965	None	$1,965

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
CHBA BC - BC Homes magazine	Congratluations to the Georgie Award winners and promote EEC in residential construction.	April - May	FEU	$1,965	None	$1,965
CHBA BC - BC Homes magazine	Energy efficienct equipment in residential construction.	June - July	FEU	$1,965	None	$1,965
CHBA Victoria – Directory	Energy efficiency in residential construction	February	FEVI	$1,275	None	$1,275
Residential Audience - One-off						
Thrifty Foods magazine	Support awareness of incentives available to customers, and ways to save energy at home	June - August	FEVI	$2,425	EEC Residential	$4,850
Dahong Philipino Publishing	Support outreach event and promote energy conservation	June	FEU	$650	None	$650
Times Colonist	Promotion of our attendance at the CHBA Victoria Home Show	February 17	FEVI	$750	None	$750

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Living Greener City of Kelowna calendar	General promotion of EEC initiatives	2010	FEI - Kelowna	$1,400	None	$1,400
Prosper Media Group - Niche Magazine	Energy efficient appliances in residential construction			$1,437	Other FEU department	$2,873
Trader Corporation - Greater Vancouver Home Builders' Association - Directory	Energy efficiency in residential construction	Feburary	FEI - Lower Mainland	$650	None	$650
Niche magazine	Congratulate Tommie award winners (home building awards) and promote the benefits of EEC for residential construction	February	FEI - Okanagan	$2,875	n/a	$2,875
Commercial Audience - One-off						
Office Space magazine	Commercial conservation and programs	April	FEU	$396	EEC - Commercial	$3,300

Publication	Subject Matter	Dates	Location	FEU Cost Contribution Under CEO Portfolio	Partner	Total Cost of Ad
Bill Inserts						
Residential bill insert	BC Spring and Garden Home Show booth and admission discount offer	February	FEI - Lower Mainland	$6,872	None	$6,872
Residential bill insert	CHBA Victoria Home Show booth and customer admission discount offer	February	FEVI - Greater Victoria	$2,516	None	$2,516
Residential bill insert	EEC programs and outreach events	June	FEU	$11,169	None	$11,169
			TOTAL	**$100,502**		**$186,302**

122.0 Reference: Energy Efficiency and Conservation

Exhibit B-9, BCUC IR 217.1

Energy Solutions Managers and Specialists

"In BC, BC Hydro, for example, has their Key Account Managers, one of whose key roles is garnering commercial, industrial and institutional customer participation in BC Hydro's PowerSmart initiatives. In Ontario, Enbridge Gas Distribution has Energy Solutions Consultants who work with commercial, industrial and institutional customers to increase participation in Enbridge's DSM initiatives."

122.1 Please confirm that FEU funded or hired for its Energy Solutions Manager and Energy Specialist positions in late 2010 or 2011.

Response:

Please note that, unlike the Energy Solutions Manager position, the Energy Specialist position is hired directly by the participating organizations in the Energy Specialist Program. The Energy Specialist position is not considered to be a position employed by the FEU. The FEU provide a set amount of funding to participating organizations to assist with covering the salary paid for this position. The Energy Specialist is then accountable for this funding by providing a report every three months which details how they have met the goals and objectives of the position. The FEU screen potential candidates for Energy Specialist positions based on the program's educational requirements but does not participate directly in the hiring process.

Participating organizations in the Energy Specialist Program were given approval in May 2010 by the FEU to seek candidates for their respective Energy Specialist positions. The first Energy Specialist was hired in May 2010 with the other positions being filled through the middle and later part of 2010 and into early 2011. As there has been some turnover in the role, some participating organizations currently have vacant Energy Specialist positions that they are seeking to hire for.

The Energy Solutions Manager positions are employed directly by FEU. The timeline for the hiring of these positions was stated on pages 237 and 238 of the 2010 EEC Annual Report:

"In spring 2010, the Companies recognized the need to proactively pursue energy efficiency and conservation opportunities directly with existing and potential commercial and institutional customers. In response to this need, the Companies took the initiative to develop three new roles within the sales department in May 2010 to focus specifically on energy efficiency and conservation. Recruitment began in June and all three positions were filled by December 2010. The three positions were stationed in the Lower

Mainland, the Interior and on Vancouver Island. The position on Vancouver Island was the last one filled and, therefore, no expenditures appear in 2010 for FEVI. Approximately $200,000 was spent to fund these positions in 2010."

122.2 Please confirm that FEU has not evaluated the energy savings impact of the Energy Solutions Manager and Energy Specialist positions to date.

Response:

The primary goal of the Energy Solutions Manager position is to increase participation in FEU Energy Efficiency and Conservation (EEC) programs. The Energy Solutions Manager position is considered to be an enabling activity and therefore supports the FEU's EEC program development and delivery but does not have energy savings directly associated with it. The Energy Solutions Managers track their success based on the number and total incentive value of the EEC program applications that they source or assist with – energy savings are associated with the EEC programs and increased participants therein rather than with the Energy Solutions Manager roles. The FEU have not formally evaluated the increased EEC program participation associated with the Energy Solutions Manager position at this time.

The Energy Specialist position is also considered to be an enabling activity and therefore supports FEU's EEC program development and delivery but does not currently have energy savings directly associated with it. The Energy Specialist position has three main objectives. In order of importance they are:

1. Increase participation in FortisBC's DSM programs
2. Develop and execute other projects that result in natural gas savings
3. Work with the (BC Hydro funded) Energy Manager on projects that result in holistic energy savings

Energy Specialists provide a report every three months to the FEU outlining the projects they have completed or are working on that meet objectives #1 and #2 above. This includes an estimate on the number of gigajoules projected to be saved for each project. However, as part of the pilot program evaluation, the FEU are still investigating ways to credit Energy Specialists directly for their contribution to attaining energy savings and verify these energy savings so that they can be officially reported on.

122.3 Have either BC Hydro or Enbridge evaluated the impact of their Key Account Managers or Energy Solutions Consultants? If so, what were the findings?

Response:

No formal evaluation study has been conducted to date by BC Hydro or Enbridge to evaluate the impact of their Key Account Managers or Energy Solutions Consultants.

BC Hydro does not evaluate individual elements or components of a DSM program. However, surveys have shown that customers rate Key Account Managers as an important element of BC Hydro's DSM programs.

Enbridge's Energy Solutions Consultants help deliver Enbridge's DSM programs and assist customers with custom programs. No evaluation study has been conducted regarding their impact.

123.0 Reference: Organizational Performance - Balanced Scorecard

Exhibit B-6, BCOAPO IR 1.7.1

123.1 How far in advance does FEU set Balanced Scorecard targets? Have the targets been set for 2012/2013?

Response:

The FEU's scorecard targets are set annually reflective of the key objectives and success measures that the Companies expect to achieve in the upcoming year.

At this time, targets have not been set for the upcoming 2012-2013 years.

123.2 Who determines which targets are appropriate for the Group's scorecard?

Response:

The FEU's scorecard targets are reviewed and revised annually by the Executive Leadership Team and approved by the Board of Directors.

123.3 How does the Executive Leadership team's bonuses relate to the results vs. targets included on the balanced scorecard. Include % allocations where they exist.

Response:

The Executive Leadership team participates in an annual incentive plan which provides for annual cash bonuses that are determined by the way of an annual assessment of corporate and individual performance in relation to targets approved by the Board of Directors. Corporate performance is determined as measured on the Scorecard. Individual performance is determined with reference to individual contribution to corporate objectives.

For the President and Chief Executive Officer, 70% of the annual cash bonus is based on corporate targets and 30% is based upon personal targets. For each of the other executives, 50% of the annual cash bonus is based upon corporate targets and 50% is based upon personal targets.

By placing a significant portion of compensation at risk, the annual incentive plan rewards achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Companies.

123.4 How are targets included in the scorecard determined? For example, how was net earnings, base capital and O&M per customer determined?

Response:

Targets for the scorecard measures are set annually taking into consideration factors such as Commission approved spending and return and also historic performance.

For the net earnings, base capital and O&M per customer measures, the targets are based on the costs and revenues used in the rates approved by the Commission.

For non-financial measures such as Recordable Vehicle Accidents, Recordable Injuries and Wellness, the annual targets are determined based on historic performance, using a rolling three year average and industry comparisons.

123.5 How are the targets rated? For example, is it better or worse to have results that are higher than net earnings targets, O&M per customer targets or base capital targets?

Response:

The balanced scorecard contains performance measures that are designed to align the interests of the shareholder, customers and employees.

Measures such as Customer Satisfaction and Service Quality Indicators ensure that providing a safe reliable service is not compromised in the pursuit of lower costs and higher earnings. The Customer scorecard measures, O&M per Customer and Base Capital are primarily for the benefit of the customer as the measures are indicators of the Companies' success in managing and containing costs, while still providing a safe and reliable service to customers. Over the long term, success in these two measures serves to minimize rate increases for customers.

Accordingly, results that exceed certain targets are good, e.g. earnings and customer satisfaction, etc. while those that are at or below target are desirable for others, e.g. O&M per customer, capital spending, accident and injury rates, etc.

123.6 By setting targets for net earnings, and O&M per customer, doesn't the target included in the balanced scorecard incent management to pursue growth in O&M budgets, defer O&M Costs and indirectly grow rate base to increase net earnings of the regulated utility in order to meet performance targets, even if such activity is not necessary in the best interests of ratepayers?

Response:

No. As indicated on page 33 of the Application, the targets for net earnings and O&M per customer are based on the costs and revenues used in the rates approved by the Commission. The Companies are therefore targeting the Commission-approved net earnings and O&M for the utilities, which is appropriate.

The scorecard is designed to be balanced in nature, including measures that align the interests of the shareholder, customers and employees. The financial target is concerned with the shareholder's opportunity to a fair return as approved by the Commission. The financial target is balanced by the other targets on the scorecard which serve to incent spending at appropriate levels for the benefit of customers and employee safety. The O&M per customer target incents management to be disciplined in spending and meet or come under the O&M forecasts used in the Commission-approved rates, as well as cost-effectively add new customers. Similarly, the capital spending measure provides incentive to be disciplined in the deployment of capital and actually suppresses rate base growth. The customer satisfaction and safety metrics provide incentives to ensure the appropriate levels of capital and O&M spending are incurred to deliver an appropriate and safe level of service. The scorecard has bands above and below the targets to ensure incentives are provided to direct behaviour to ensure targets are met.

123.7 Is setting a target of net income and O&M per customer contrary to the regulatory compact for a regulated utility?

Response:

No. The FEU's objective is to achieve the allowed earnings and this is accomplished by delivering service to customers at or below the approved cost of service, which includes O&M spending among other things.

Please also refer to the response to BCUC 2.123.5.

123.8 If FEU was not regulated, would the balance scorecard include rising O&M per customer targets year after year?

Response:

The FEU are regulated utilities under the UCA and have obligations to serve customers and are subject to safety and compliance requirements that typically do not exist for non-regulated business. Non-regulated businesses are more free to set prices and determine the service level they will provide without oversight or input from third parties. As such, and depending on the business models and strategy pursued, O&M per customer levels might rise or fall.

The O&M per customer target is based on the O&M approved in the cost of service used to set rates and the forecast of customers each year. If the FEU were not regulated, there would not be an approved cost of service so it is not possible to answer the question as posed.

For clarity, FEU provides the O&M per customer scorecard targets per year from 2006 to 2011.

2010 and 2011 O&M per customer targets are higher than 2009 and prior years, reflective of the cost pressures that FEU face and for which funding was approved by the Commission. However, for years 2009 and prior, the O&M per customer targets essentially fall within a narrow range and are not rising "year after year".

Year	O&M per Customer Target
2006	$ 234.00
2007	$ 231.00
2008	$ 231.31
2009	$ 238.09
2010	$ 255.64
2011	$ 259.72

Like any other company, the FEU's intention is to operate as efficiently as possible while delivering service customers expect.

123.9 For 2010- 2007, What is the group's net earnings as a percentage of i) customers served and ii) GJ delivered to customers?

Response:

The FEU interprets the above question as asking the FEU gas net earnings expressed over the number of customers served and the number of gigajoules delivered for the respective years.

The FEU provides a summary below of the actual net earnings per customer served and per GJ delivered for 2007-2010.

		2010	2009	2008	2007
FEU Group Earnings - per Scorecard	($MM)	127.3	112.4	111.7	108.2
Customers Served - per Appendix B-3					
FEI		843,846	836,918	831,845	822,598
FEVI		100,140	97,708	94,773	91,245
FEW		2,592	2,580	2,457	2,411
FNG		2,388	2,367	2,369	2,368
FEU		948,966	939,573	931,444	918,622
GJ Delivered - per Appendix B-3	(000)	201,111	200,822	210,091	214,819
FEU Earnings per Customer		**134.15**	**119.63**	**119.92**	**117.79**
FEU Earnings per GJ Delivered		**0.63**	**0.56**	**0.53**	**0.50**

The higher earnings per customer and GJs delivered in 2009 and 2010 were primarily due to the higher allowed return on equity and equity thickness approved by the Commission.

123.10 Please explain why vehicle accidents have sharply increased in 2008-2009?

Response:

A change in the industry definition of the measure explains the increase in the number of vehicle accidents reported in 2009 (38 accidents) compared to prior years of 2008 (13), 2007 (10) and 2006 (21).

Starting in 2009, the corporate definition of the Recordable Vehicle Accident measure was changed in order to align with the Canadian Gas Association reporting which included all avoidable and non-avoidable accidents, irrespective of the damage amounts.

Please also refer to the response to BCOAPO IR 1.7.2.

124.0 Reference: Energy Efficiency and Conservation

Exhibit B-7, BCSEA IR 1.7.1 and the Utilities Commission Act, s. 44.2 Approvals

*"**44.2** (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:*

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;…

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate." (UCA)

"A prior public interest approval of an expenditure schedule is evidence in a rate-setting proceeding that it was prudent for the utility to engage in the type of past activities contemplated in an accepted schedule (and thus assists the utility in being able to recover in rates the forecast amortized cost of those activities occurring during the test period as prudent forecast costs of service)." (BCSEA 1.7.1)

124.1 Please comment on the position FEU confirmed in its response to BCSEA IR 1.7.1 in relation to section 44.2 of the Utilities Commission Act. Does FEU not need a prior section 44.2 approval for a DSM expenditure schedule to recover the DSM expenditures in rates?

Response:

As noted in the question and in Commission Order G-145-11, section 44.2(2) of the *Utilities Commission Act* requires the acceptance of a DSM expenditure schedule before such DSM expenditure can be recovered in rates. This is an exception to the general rule that expenditure schedules are optional and should have been noted in our response to BCSEA IR 1.7.1 and in our submissions in the NGV Incentive Review Proceeding. The implication of this provision is that a utility requires acceptance under section 44.2 for DSM expenditures it has made or anticipates making in order to have rates amended to recover such costs.

125.0 Reference: EEC Amortization Expense

Exhibit B-7, BCSEA IR 1.13.1

125.1 Assuming that FEU were to spend $70M per year for each, starting in 2012, of the next 10 years, what would be the amortization expense in year 10 and how does that compare to year 1 in 2012.

Response:

Please refer to tables below and the associated notes with each table. Under the scenario as described in the question the amortization expense in year 10 for the FEU is forecast at $48.1 million as compared to amortization expense of $2.8 million in 2012.

Please refer to the response to BCUC IR 2.93.2 and BCUC IR 2.93.3.1. As discussed in those responses, the FEU have not proposed that a funding envelope of $74.5 million per year pertaining to the EEC program continues in perpetuity. The EEC program is reviewed on a regular basis and FEU may seek changes to the level of the EEC funding envelope in future revenue requirement or long term resource plan applications, in accordance with the success of the program and the achievement of energy efficiency and conservation targets.

EEC Rate Base Deferral Amortization Expense ($000s) [1]	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Mainland	$ 2,561	$ 3,950	$ 5,287	$ 6,622	$ 7,957	$ 9,292	$ 10,627	$ 11,853	$ 13,973	$ 12,178
Vancouver Island	$ 281	$ 431	$ 581	$ 731	$ 881	$ 1,031	$ 1,181	$ 1,331	$ 1,472	$ 1,367
Whistler	$ -	$ 15	$ 30	$ 45	$ 60	$ 75	$ 90	$ 105	$ 120	$ 135
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FortisBC Energy Utilities	$ 2,842	$ 4,396	$ 5,898	$ 7,398	$ 8,898	$ 10,398	$ 11,898	$ 13,289	$ 15,565	$ 13,680

[1] Includes $20 million of additions each year allocated 89%/10%/1% to FEI, FEVI and FEW respectively

EEC Non-Rate Base Deferral Amortization Expense ($000s) [2, 3]	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Mainland	$ -	$ -	$ 7,287	$ 10,625	$ 13,962	$ 17,300	$ 20,637	$ 23,975	$ 27,312	$ 30,650
Vancouver Island	$ -	$ -	$ 816	$ 1,191	$ 1,566	$ 1,941	$ 2,316	$ 2,691	$ 3,066	$ 3,441
Whistler	$ -	$ -	$ 81	$ 119	$ 156	$ 194	$ 231	$ 269	$ 306	$ 344
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FortisBC Energy Utilities	$ -	$ -	$ 8,185	$ 11,935	$ 15,685	$ 19,435	$ 23,185	$ 26,935	$ 30,685	$ 34,435

[2] For simplicity, AFUDC was only calculated on 2012 and 2013 additions for the amortization amounts included in this table

[3] Includes $50 million of additions each year allocated 89%/10%/1% to FEI, FEVI and FEW respectively

EEC Total Deferral Amortization Expense ($000s)	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Mainland	$ 2,561	$ 3,950	$ 12,574	$ 17,247	$ 21,919	$ 26,592	$ 31,264	$ 35,828	$ 41,285	$ 42,828
Vancouver Island	$ 281	$ 431	$ 1,397	$ 1,922	$ 2,447	$ 2,972	$ 3,497	$ 4,022	$ 4,538	$ 4,808
Whistler	$ -	$ 15	$ 111	$ 164	$ 216	$ 269	$ 321	$ 374	$ 426	$ 479
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FortisBC Energy Utilities	$ 2,842	$ 4,396	$ 14,083	$ 19,333	$ 24,583	$ 29,833	$ 35,083	$ 40,224	$ 46,250	$ 48,115

125.2 What would be the impact increase as a percentage on average customer bills, in 2012, if the amortization expense in 2012 was that of year 10 vs. year 1. Amounts can be discounted using inflation rate, however carrying costs for deferral accounts such as ROE or interest should also be factored into this calculation.

Response:

The following tables show the derivation of the approximate high-level annual bill impact for the FEU if the forecast 2021 EEC amortization expense (as derived in the response to BCUC IR 2.125.1) and mid-year balance of the deferral accounts was embedded in the 2012 revenue requirements. Please note that this is a high level analysis that does not take into consideration reductions in volume and commodity costs that customers would experience when EEC incentives of this level are achieved.

Under this scenario, the following annual bill impacts are estimated as follows:

- FEI customers would see an approximate annual bill increase of 2.6%.

- FEVI customers would not see a rate increase as the impact would be managed through the use of the RSDA; however, the increase to the revenue requirement is approximately 2.2%.
- FEW customers would see an annual bill increase of approximately 3.5%.
- For simplicity of the long term analysis provided in the response to BCUC IR 2.125.1, the allocation of the additions in the EEC non-rate base deferral account was on an average customer basis. This allocation basis results in zero additions to the Fort Nelson EEC account; therefore, under this scenario, Fort Nelson customers would not see an impact as EEC costs have not been allocated.

FEU Overall Impact on Rates for 2012

	Amortization Expense	Tax Expense	Earned Return	Total Cost of Service	2012 Non-Bypass Revenue [1]	% Impact on Rates [2]
FEI	$ 19,617	7,885	4,039	31,541	1,204,417	2.62%
FEVI	2,304	935	501	3,741	174,353	2.15%
FEW	264	98	30	391	11,209	3.49%
Fort Nelson	-	-	-	-	4,774	0.00%
Total	$ 22,185	$ 8,918	$ 4,570	$ 35,673	$ 1,394,753	

1 Evidentiary Update Filed July 19, 2011, Tabs 7.1, 7.2, 7.3 & 7.4, Schedule 14, Total Non-Bypass Sales & T-Service Revenues at Existing Rates.

2 For FEVI there would be no impact on customer rates as the change in cost of service would be met through the RSDA.

The following tables provide the derivation of the changes in amortization expense and rate base (earned return). The income tax expense is derived from the changes in the amortization expense and earned return.

FEU Present Value of Amortization Expense from Year 10 Impact on Rates for 2012.

	2021 Forecast Amortization Expense	WACC After Tax	Present Value	2012 Amortization Exense [2]	Change	2012 Non-Bypass Revenue [1]	% Impact on Rates [3]
FEI	$ 42,828	6.80%	22,178	2,561	19,617	1,204,417	1.63%
FEVI	4,808	6.40%	2,585	281	2,304	174,353	1.32%
FEW	479	6.15%	264	-	264	11,209	2.35%
Fort Nelson	-	6.79%	-	-	-	4,774	0.00%
Total	$ 48,115		$ 25,027	$ 2,842	$ 22,185	$ 1,394,753	

1 Evidentiary Update Filed July 19, 2011, Tabs 7.1, 7.2, 7.3 & 7.4, Schedule 14, Total Non-Bypass Sales & T-Service Revenues at Existing Rates.

2 BCUC IR 2.125.1, 2012 Forecast

3 For FEVI there would be no impact on customer rates as the change in cost of service would be met through the RSDA.

FEU Present Value of Rate Base from Year 10 Impact on Rates for 2012

	2021 Forecast Mid-Year Rate Base	WACC After Tax	Present Value	2012 Mid-Year Rate Base [2]	Change	Earned Return Impact	2012 Non-Bypass Revenue [1]	% Impact on Rates [3]
FEI	$ 256,552	6.80%	132,853	26,571	106,282	4,039	1,204,417	0.34%
FEVI	29,162	6.40%	15,680	3,147	12,533	501	174,353	7.19%
FEW	1,490	6.15%	820	75	745	30	11,209	6.65%
Fort Nelson	-	6.79%	-	-	-	-	4,774	0.00%
Total	$ 287,204		$ 149,353	$ 29,793	$ 119,560		$ 1,394,753	

1 Evidentiary Update Filed July 19, 2011, Tabs 7.1, 7.2, 7.3 & 7.4, Schedule 14, Total Non-Bypass Sales & T-Service Revenues at Existing Rates.

2 July 19th Evidentiary Update Section 7, Tabs 7.1-7.4, Schedule 68

3 For FEVI there would be no impact on customer rates as the change in cost of service would be met through the RSDA.

The discount rate used in the analysis is based on the capital structure and embedded cost at revised rates from the July 19, 2011 Evidentiary Update Schedule 80 for each of the utilities (Tabs 7.1, 7.2, 7.3 & 7.4). The forecast amortization expense in year ten is from the response to BCUC IR 2.125.1 and is the 2021 Forecasted Total Amortization Expense for both Rate Base and Non-Rate Base.

The formula for discounting to the present value is:

(2021 Amortization Expense or mid-year rate base) / (1 + Discount Rate)

126.0 Reference: Revenue Requirements and Rates

Exhibit B-8, CEC IR 1.4.9 , p. 29

Vancouver Island Effective Rates

"Thus once hedges are in place, if market prices move adversely, the impact on the GCVA balance will be significantly reduced. This helps to preserve the overall GCVA and RSDA surplus, and mitigate future rate increases for customers."

126.1 If market prices move in a way that is not adverse, does FEU agree that it is possible that hedging costs could be viewed as effectively having eroded the overall GCVA and RSDA surplus and thereby potentially resulting in unnecessary increases in future rates?

Response:

Per the letter to the Commission dated August 4, 2011, FEVI has withdrawn its request to hedge incremental volumes for 2012 and 2013.

Without hedging, if market prices move downwards, the GCVA and RSDA surplus will increase above 2011 forecast levels and if market prices move upward, the GCVA and RSDA surplus will decrease below 2011 forecast levels.

If FEVI proceeded with the request to hedge incremental volumes for 2012 and 2013 and if market prices had moved in a way that was not adverse, approved hedges would not have eroded the overall GCVA and RSDA surplus but rather would have maintained the GCVA and RSDA surplus at forecast levels at the end of 2011. Similarly, if prices moved adversely, the approved hedges would have also maintained the GCVA and RSDA surplus at forecast levels.

126.2 If no further hedging is approved by the Commission for FEVI, would FEU propose a rate increase a method of protection for preserving the RSDA for future years? If not, please explain your response.

Response:

As indicated in the response to BCUC IR 2.126.1, FEVI has withdrawn its request to hedge incremental volumes for 2012 and 2013.

FEVI has proposed to maintain FEVI rates at existing levels without the assurance of incremental hedging to preserve the RSDA. FEVI does not see a basis to alter the proposal at this time and seek a rate increase in 2012 and/or 2013. The outcome of the request for approval of amalgamation and rate harmonization for the FEU will significantly impact any methods considered by FEVI for preservation of the RSDA.

127.0 Reference: Revenue Requirements and Rates

Exhibit B-8, CEC IR 1.4.9 , p. 29

Vancouver Island Effective Rates

"Thus once hedges are in place, if market prices move adversely, the impact on the GCVA balance will be significantly reduced. This helps to preserve the overall GCVA and RSDA surplus, and mitigate future rate increases for customers."

127.1 If market prices move in a way that is not adverse, does FEU agree that it is possible that hedging costs could be viewed as effectively having eroded the overall GCVA and RSDA surplus and thereby potentially resulting in unnecessary increases in future rates?

Response:

This question is a repeat of BCUC IR 2.126.1, please refer to the response to BCUC IR 2.126.1.

127.2 If no further hedging is approved by the Commission for FEVI, would FEU propose a rate increase a method of protection for preserving the RSDA for future years? If not, please explain your response.

Response:

This question is a repeat of BCUC IR 2.126.2, please refer to the response to BCUC IR 2.126.2.

128.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, p. 29

Give Your Furnace Some TLC Program

128.1 Please list every EEC program FEU currently runs or is proposing to run that provides incentives for customers but has no direct energy savings attributable.

<u>Response:</u>

There are three major areas where the FEU have provided incentives to customers that lead to energy savings, but where no direct energy savings have been attributed to date:

- Appliance service programs
    - 2010 -"Give your furnace some TLC" furnace service program
    - 2011 -"Give your furnace or fireplace some TLC" appliance service program
- Home Energy Assessment Subsidies
    - 2009-2010 Home Energy Assessment subsidy in partnership with LiveSmart BC and utility partners (Joint Initiative)
    - 2011 Home Energy Assessment subsidy in partnership with LiveSmart BC and utility partners (Joint Initiative). This initiative will be categorized as a non-incentive, marketing expenditure
- Energy Management Funding
    - Energy Specialist Pilot Program

These are discussed further below.

<u>Appliance Service Program: "Give your furnace some TLC"</u>

The primary objectives of the 2010 and 2011 appliance service program are to promote energy efficiency dialogues between contractors and customers, and to ensure natural gas appliances are operating as efficiently as possible. The program facilitates the opportunity to identify installation issues, gas leaks, and appliances in need of upgrade or replacement. Based on the 2010 "Give your furnace some TLC" participant survey, over 25% of customers directly benefited from the program in that 4% reported gas leaks, 6% reported technical issues and 15% of customers were encouraged to upgrade or replace their old furnaces with high efficiency models . Thus, this is an energy savings enabling activity. Half of those applicants who were encouraged to upgrade or replace their furnace took action and replaced or upgraded to a high efficiency appliance.

The FEU are investigating potential methods of measuring and attributing energy savings as part of the furnace service. Energy savings claims for the appliance service program may be included in the 2011 EEC report.

Home Energy Assessment Subsidies

In subsidizing home energy assessments, the FEU encourage their customers to undertake a whole home approach to energy efficient retrofits and drive immediate and longer term energy savings in natural gas heated homes. This is an enabling activity to the energy savings associated with the Companies' contribution to the LiveSmartBC initative. By working with Certified Energy Advisors, customers gain insights into appliance upgrades, insulation, and draft proofing that will improve the air quality and comfort of their homes and ultimately lower their energy bills. In the 2010 EEC report, although the FEU made direct payments to customers, home energy assessments were included as non-incentive spending in TRC calculations. Home Energy Assessment subsidizations will be the major component of a FEU/LiveSmartBC fall marketing initiative to drive program participation. Because LiveSmartBC program partners had to wait for the federal EcoENERGY Home Retrofit announcement (July 2011), the LiveSmartBC market exposure has been very limited. Therefore the FEU wanted to ensure that their customers and trade allies were aware of these programs and could thus take advantage of rebates for home retrofits that can drive significant energy savings for the province of BC.

Energy Management Funding

Please see also the response to BCUC IR1.217.2.1.

The Energy Specialist Program is defined as an enabling activity and as such supports the FEU's EEC program development and delivery but does not have energy savings directly associated with it. In the past, a major barrier to EEC program adoption has been facilitation of equipment installation and application administration on the customer side, for commercial and institutional customers. Potential program participants are often lost because they do not have the resources available to implement the measures required for program participation, nor the time to go through the application process. In these instances, the potential participant has the desire and financial means to implement the required measure but not the human resources to make it happen. The Energy Specialist program has been put in place to combat this issue. The pilot program is currently being evaluated to determine its overall viability, assess program delivery and reporting mechanisms, and full program roll-out options. Attribution of additional program participation, and therefore increased energy savings, will be reported upon in the 2012 EEC Annual Report.

128.1.1 Please justify the EEC incentive offering in each of these cases.

Response:

Please see the response to BCUC IR 2.128.1.

129.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, p. 33

Efficient Hot Water Heater Storage

"The 2010 0.62 EF water heater program was introduced primarily as a compliance engagement program to be in the market until December 31, 2010; however, with lower than anticipated participation rates and anecdotal evidence of a large number of non-compliant tanks in market,the Companies are extending the existing base offer for the 2011 calendar year."

129.1 Please explain why FEU claims savings from this program when it is incenting code compliant water heaters. How were the measure savings calculated?

Response:

There are many benefits associated with leaving the 0.62EF water heater program in market for the duration of the 2011 calendar year. The FEU are investing significant resources in a national water heater transformation strategy, for which the 2010 0.62EF water heater program was the first step in developing partnerships with manufacturers, distributors, contractors and retailers. Since water heaters represent 21% of residential natural gas consumption, it is important to have a longer term program in place to continue to build on these relationships. The FEU will be enhancing the 0.62 EF program by introducing ENERGY STAR tanks (0.67EF), however there are very few 0.67EF units currently available in the market. In addition, new technologies such as tankless water heaters and condensing tanks will be introduced to the water heater program when cost benefit analysis is completed and when the decision regarding the use of the SCT rather than traditional TRC is known. Furthermore, feedback from contractor research states that it creates great market confusion when programs are started and stopped. Therefore, the FEU felt it would be most effective to leave the base offer in place, until the next program iteration supporting higher EF equipment could be in market.

Water heating technology has not improved much over the past 50 years and utility programs in alignment with regulations are a way of creating change in the industry. The province of BC is the only jurisdiction in North America that has increased the regulation to 0.62 EF, so some manufacturers have been slow to change while others made a significant investment to comply. Furthermore, the Efficiency Rating is not clear on many water heaters in market. These programs help drive product labelling as an important first step in efficiency awareness. It is the FEU's belief that the program, which assisted in bringing the attention of the new regulation to customers and contractors, helped drive manufacturer compliance with the existing 0.62EF regulation.

The FEU, as part of the program, have created a directory of eligible water heaters on the www.fortisbc.com website. Without this program, this directory, which provides an ongoing compliance engagement tool, would not be in existence.

The program also offers the opportunity to provide a hot water heater early retirement message. The home insurance industry informed us that water damage is the highest proportion of claims and that a substantial proportion is due to water heater failure. In promoting the program, especially in retailer settings, and at home shows, customers are reminded to replace their water tanks before failure.

The FEU will be working on providing an incentive for 0.67 EF (ENERGY STAR) water heaters in the coming months. The 0.62 EF incentive will be removed from the market December 31, 2011.

The measure savings of 2 GJs was calculated according to the following research:

- FEU's 2 GJ savings claim per 0.62EF natural gas water heater is supported by the Canadian Residential Water Heater Market Assessment, prepared by Caneta Research for MEMPR in 2009. As per Table 21: Natural Gas Fired Hot Water Heater benchmark analysis, Caneta's 2009 research found that a 0.58EF natural gas hot water heater, commonly found in residential applications, consumes 29.19GJs/year in comparison to 27.28 GJs/year per 0.62EF natural gas water heater.
- FEU's 2 GJ savings claim per 0.62EF natural gas water heater is further supported by Jack Habart's 2010 Market Transformation Domestic Water Heater Strategy prepared for FortisBC- marked for discussion only not for quotation or attribution, and filed as Appendix I to Appendix K-3 to Exhibit B-1, the 2009 EEC Annual Report. Habart's 2010 research found similar results as Caneta's 2009 research prepared for MEMPR. As per Exhibit 3.1 of this document, Habart's 2010 research found that 0.57EF natural gas water heaters, commonly found in residential applications, consume 20.4 GJs/year in comparison to 18.5 GJs/year per 0.62EF natural gas water heater.

129.2 Please explain the large number of non-compliant tanks in market. Are retailers stocking non-code compliant heaters? If so, what is the most effective way to address this issue?

Response:

Compliance enforcement is under the jurisdiction of the Ministry of Energy and Mines and not that of the FEU, however the utility supports regulation compliance. Currently, Energy Efficiency Act Standards refers to the enforcement of "manufacturing" of non-compliant tanks rather than "selling" of non-compliant products. Some dealers may stockpile non-compliant products (such as the case with mid-efficient furnaces) or obtain products from other jurisdictions. The Ministry of Energy and Mines has recently undertaken a consultation around regulation compliance, and until the results of that consultation are made public, and as compliance is outside the Companies' jurisdiction, the FEU would prefer not to comment on the most effective way to increase compliance. While the FEU have yet to formulate an opinion on the most effective way to enforce compliance, providing a directory of rebate eligible (compliant) water heaters on fortisbc.com provides an engagement tool. Manufacturers must ensure that their products are registered with NRCan, contractors and retailers must be aware that their inventory is on the list, while customers demanding rebate-eligible product check the list as part of their purchase decision. Education and awareness within each of these stakeholder groups helps drive compliance.

129.3 What evidence, other than anecdotal, does FEU have that compliance for this code is low?

Response:

Based on program applications to date, 6% have been rejected due to the customer or contractor installing non-compliant models. Since these applications represent only customers or contractors that are aware of an energy efficiency rebate program, this would suggest that the market availability of these non-compliant models is much greater than 6%. A market research study is currently under way through phone surveys and mystery shopping to get a more clear understanding of the market penetration of non-compliant models and also to determine the availability of ENERGY STAR models for the introduction of new efficiency tiers for the next program iteration.

129.4 Please confirm that the Efficient Hot Water Heater Storage Program is labeled ENERGY STAR Hot Water Heaters in the spreadsheets attached to BCUC IR 189.1.

Response:

Yes the program listed in the BCUC IR 1.189.1 as the ENERGY STAR water heater program is the 0.62 EF water heater program. During 2010, it was uncertain when the new ENERGY STAR ratings would come into effect, and the program was initially conceived of as "ENERGY STAR" water heater program until the fall of 2010 when the new efficiency tiers were announced. Therefore, there was some confusion on program naming in spreadsheet templates that were created prior to September 2010.

129.5 Please list every EEC program FEU currently runs or is proposing to run that provides incentives for customers to comply with a code or standard currently in place.

Response:

Generally speaking, utility incentives are phased out as efficient equipment market saturation levels reach a point at which the efficient equipment is the generally installed option, and a regulatory body feels comfortable implementing a regulation which requires the efficient option as the minimum standard. The point at which utility incentives are no longer required, however, varies from equipment type to equipment type as stated in BCUC IR 1.217.4.2. In the case of residential water heaters and residential furnaces, EEC programs have been designed to accelerate consumer compliance.

The "Efficient Hot Water Heater Storage" program and the planned 2012 "Furnace Scrap-It" program both incent customers to comply with a code or standard currently in place. As stated in BCUC IR 1.217.4.1 the implementation of a regulation does not necessarily result in a rise in general baseline equipment efficiency in the marketplace. The "Furnace Scrap-It" program responds directly to this issue. The minimum equipment performance standard for furnaces is 90 percent; however the Companies' Residential End Use Survey suggests that only 16% of the Companies' residential customers have high efficiency furnaces (90% AFUE and higher), 39% have mid efficiency furnaces (78% to 85% AFUE), and 45% have standard efficiency furnaces (less than 78% AFUE). This indicates that 84% of the Companies' customers have either a need to upgrade their standard efficiency furnaces or have mid-efficiency furnaces that are close to the end of their useful lives. This initiative could help remove financial barriers for proactive furnace replacement and would provide a significant opportunity for energy savings and GHG emissions reductions.

Please refer to the responses to BCUC IRs 2.129.1, 2.129.2 and 2.129.3 for information on the Efficient Hot Water Heater Storage program offering.

129.5.1 Please justify the EEC incentive offering in each of these cases. Provide evidence, other than simply anecdotal evidence, of non-compliance with the code or standard which warrants EEC incentive spending.

Response:

Please see the response to BCUC IR 2.129.5.

130.0 Reference: Thermal Energy Services

Exhibit B-1, Part 1.2, p. 10

Thermal Energy Services

"Approval to pursue Alternative Energy Services (which the Companies are now referring to by the more descriptive name "Thermal Energy Services") ***within the utility****."* [Underlined for emphasis] (Exhibit B-1, p. 10)

130.1 Please explain why a non-regulated FortisBC or Fortis entity cannot not offer Thermal Energy Services?

Response:

According to the definition of a "public utility" in the Utilities Commission Act all thermal energy services (TES) such as discrete energy systems, solar district energy and geo-exchange that involve service to the public or a corporation for compensation would meet the requirements of this definition and therefore be regulated. The thermal energy services that the FEU will be offering are therefore regulated. It is appropriate that these systems to be included as regulated services within the FEU lines of business in a similar fashion to propane service being provided by FEI to Revelstoke within a single regulated entity. This approach can provide benefits to the two classes of service over time by sharing common service costs, which has direct benefits to customers.

130.2 Would it be possible for FEU to offer the Thermal Energy Services through a non-regulated entity? If not, explain what factors would prevent such a structure?

Response:

No, it would not be possible to do this because the services are regulated services under the UCA if they meet the definition of "public utility" services. Any entity that offered the same services as the FEU is contemplating providing would be regulated as a "public utility" in respect of those services. The alternative to the model that the FEU are advancing is one in which there are multiple small regulated thermal energy utilities within the Fortis umbrella. The Commission has previously expressed reservations about such a proliferation of small utilities, and encouraged the FEU to offer propane services within the larger utility. The FEU believe the same logic is equally appropriate when it comes to thermal energy utilities. A public utility such as the FEU can offer expertise and share overheads among its classes of service, such as thermal Energy services, to reduce overhead costs so that the end user rates are lower for all classes of service within that regulated public utility.

131.0 Reference: Thermal Energy Services

Exhibit B-1, Part 1.2, p. 10

Ontario Energy Board, EB-2009-0172, pp. 5-7

Thermal Energy Services

"When assets are allowed in rate base it is generally because those assets are related to the monopoly franchise. Enbridge does not have a monopoly franchise for the production of renewable energy. Its franchise is related to the distribution of natural gas. To the extent that the Green Energy Initiatives involve activities for the production of renewable energy, they occur within a competitive market." (EB-2009-0172, p. 5)

131.1 Does FEU have a monopoly franchise for the production of Thermal Energy Services?

Response:

No, the FEU do not have a monopoly franchise for the production of thermal energy services in British Columbia. There is competition in the thermal energy service business since these regulated projects can be developed by other public utilities (such as Corix Multi-Utility Services) as well as Energy Services Companies (ESCOs), but in all cases the owner and operator of projects that provide service to the public for compensation are regulated and considered public utilities in BC. The scope of regulation is defined by the UCA, reflecting the legislature's decisions about who will be regulated and in what circumstances. Irrespective of economic theory regarding monopolies, regulation of public utilities must be conducted within the legislative framework applicable to BC. The FEU note that, under the UCA, the ability to own and operate assets is addressed through CPCNs, and not by granting franchises.

Moreover, the existence of multiple potential providers of thermal energy service providers in BC does not remove the economic rationale for public utility regulation. This can be illustrated by looking at electricity and natural gas utilities. Electricity and natural gas utilities are natural monopolies by virtue of it being economic to have one provider of electricity and one provider of natural gas (and one set of each type of infrastructure) within a defined geographic area. The fact that the FEU and BC Hydro already operate within the same geographic areas and offer competitive energy alternatives for heating and cooling doesn't make those entities any less of a natural monopoly in providing their respective services. In effect, the electric and natural gas monopolies compete for customers in a competitive, but regulated, energy marketplace.

(Although, in fact, it can be the case that one company offers more than one regulated service capable of meeting consumers' thermal energy needs - for example, this used to be the case with BC Hydro which had gas and electric classes of service, and the FortisBC group of companies provide currently both gas and electric service in the southern interior of BC). The existence of thermal energy infrastructure within a geographic area already served by electricity and natural gas, for instance, is really just making another energy choice available "to the public or a corporation for compensation". Central Heat, for example, operates a thermal energy natural monopoly in the same geographic area (downtown Vancouver) as BC Hydro (electricity) and FortisBC Energy Inc. (natural gas). Before an energy system is installed in a particular building or area there are many possible ways to meet the thermal energy requirements and there is competition among the monopoly providers of competing energy forms to meet the thermal energy demand. The more widespread use of thermal energy for heating and cooling is part of a natural evolution of the already competitive BC Energy market among regulated natural monopolies.

The type of competition that is being considered in the question is competition among thermal energy companies (Corix, ESAC, FEU etc.) to be the successful candidate to own and operate the natural monopoly thermal energy system in a particular geographic area (such as the area served by a district energy system). A hypothetical illustration involving a "greenfield" electric utility assists in explaining why the existence of multiple companies capable of installing and operating a district energy system does not diminish the economic rationale for regulation. There might be rivals to build the electric system, but the fact that there are rivals would not make the successful contender any less of a public utility once a CPCN was granted and the electric distribution facilities constructed. There is still a natural monopoly for the provision of electricity in the geographic area served by the greenfield utility.

Further, regulation makes sense from a consumer protection standpoint. A customer taking service from a geothermal energy utility, for example, will generally only have that one choice of providers of geothermal energy. Even if alternative energy choices for heating and cooling are available due to the presence of electric or natural gas infrastructure in the same geographic area, customers will face barriers to conversion. The conversion costs to retrofit a building for a different energy source, for instance, are often prohibitively high so the buyer is effectively captive to the seller. The same logic applies with thermal energy systems as it would for captive customers of any electric or natural gas utility, which the Commission will actively regulate.

Another recent example evidencing the role of public utility regulation in the case of competing providers is Sea Breeze's application for a CPCN for the Vancouver Island Transmission Reinforcement Project. Sea Breeze, a merchant transmission provider, was competing with British Columbia Transmission Corporation (BCTC) for a CPCN for its own transmission project to serve the same purpose. As in the case where FEU and Corix are vying to own and operate a thermal energy project, there were two competing parties seeking to own and operate a transmission line to Vancouver Island where only one line was required. The Commission granted a CPCN to BCTC (now, BC Hydro), thus recognizing that the transmission line is still appropriately a regulated asset even in the face of competing providers.

The preamble cites the decision of the Ontario Energy Board (OEB). The OEB does not regulate thermal energy services. It considers "green energy initiatives" that involve the production of "renewable energy" to be unregulated and allowed to develop in a competitive market environment. (See Decision-Enbridge Gas Distribution Inc., EB-2009-0172, pages 5 and 6). The important fact, however, is that the Ontario legislative framework permits the OEB to take that view.[36] In BC, that is not the case. The BC Legislature has determined – by virtue of the way the UCA has been written - that the provision of such services to the public for compensation should be regulated. The question of whether or not that is the correct approach in BC in light of the approach taken in Ontario is a political question for determination by the BC Legislature, and not one for the Commission to determine in this proceeding.

131.2 Are Geo-exchange, Solar-thermal and District Energy Systems assets included in the uniform system of accounts for natural gas utilities?

Response:

At its own discretion the Commission has the power under section 49 (a) of the UCA to require public utilities of the same class to adopt a uniform system of accounting. The Commission has established such uniform systems of accounts for gas utilities and electric utilities but not for other classes of utilities such as thermal energy utilities. As such, the Uniform System of Accounts for Gas Utilities was not specifically developed for use by utilities providing thermal energy services such as geo-exchange, solar and district energy systems. However, since a thermal energy utility makes use of similar infrastructure and equipment as a gas utility does, many of the accounts and account classifications in the Gas Uniform System of Accounts can be used directly or are readily adaptable to a public utility providing thermal energy service. Further, the regulatory accounting principles implicit in the Gas Uniform System of Accounts are equally applicable to a thermal energy service utility.

[36] The Ontario Energy Board Act (OEBA) specifies parameters for the regulation of natural gas "transmitters and distributors", which involves different considerations from the definition of "public utility" as defined in the UCA.

It is relevant to note that the Gas Uniform System of Accounts contemplates that utilities may be engaged in more than one class of utility service. Section 20 of the Gas Uniform System of Accounts notes that it may be necessary to account for certain assets as "Common Utility Plant" where such assets are used in support of multiple classes of service such as "electric, gas and water …" and it is impractical to segregate the assets by class of service. While the Gas Uniform System of Accounts does not deal directly with thermal energy utilities and the Commission has not yet established a uniform code of accounts for thermal energy service, neither of these facts means that the FEU are prevented from offering services apart from natural gas.

"Permitting a well financed public utility to include its costs of participation in this market into its rate base, thereby transferring risk to the ratepayer, is unfair to other market participants." (EB-2009-0172, p. 6)

131.3 Please explain why natural gas ratepayers should be at risk for costs incurred by the thermal energy line of business, rather than the FEU shareholder.

Response:

The question is based on an incorrect premise. Natural gas customers are not, under the currently approved rate constructs, at risk for the costs incurred by the thermal energy class of service. The shareholder is currently at risk. This is explained below.

The Negotiated Settlement Agreement for FEI's 2010-2011 RRA, approved by BCUC Order No. G-141-09 acknowledged that FEI would be engaged in thermal energy services. The Negotiated Settlement Agreement for FEVI's 2010-2011 RRA, approved by BCUC Order No. G-140-09, acknowledged the fact that FEVI withdrew its request in the RRA relating to thermal energy service and instead that thermal energy projects within the FEVI service area would be pursued by FEI. The parties further agreed that costs incurred by FEI to provide thermal energy services will not be recovered in FEVI's natural gas service rates. Significantly, the necessary accounting structures were put in place to separate FEI's Thermal energy services class of service from the natural gas business. As a result of the approval of that application for FEI, the activities in the area of thermal energy services are captured in a non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in the FEU 2012-2013 RRA.

The natural gas customers are, in fact, benefitting under this construct without being at risk for the costs incurred in support of the thermal energy class of service. There is a reduction in O&M included in the natural gas cost of service that is associated with the recovery of overheads from the thermal energy services class of service. In the long-run the more successful the thermal energy services class of service becomes, the greater the potential benefit to natural gas customers in terms of a recovery of overheads or common service costs.

As FEI is making progress towards developing the thermal energy class of service, it is expected that FEI will bring forth individual projects with signed contracts for Commission approval during 2011 that will also meet the terms of the NSA. Consistent with the approved framework, forecast costs for 2012 and 2013 relating to thermal energy services have been segregated and allocated to the thermal energy services class of service.

The growing prevalence of low carbon thermal solutions such as geo-exchange, solar and district energy will have an increasing impact on natural gas requirements over time. Participation by the FEU in these low carbon thermal energy solutions will help to keep natural gas as part of the energy mix for each of these services. The benefit is more natural gas throughput which helps to moderate the decline in consumption that the FEU are experiencing. The thermal energy class of service will also be able to absorb an increasing share of common costs as it grows within the utility. This will mitigate the impact of overhead costs on customer rates as these costs will be distributed over a larger natural gas volumes and across multiple classes of service.

> *"Moreover, this form of funding recognizes the fact that renewable energy will benefit all the citizens of the province and not just those within Enbridge's territory. If renewable energy costs are in rates, then the costs of projects will be paid by Enbridge's gas ratepayers. But those projects will benefit the people of Ontario regardless of where they are located."* (EB-2009-0172, p. 7)

131.4 If thermal energy projects benefit the people of British Columbia, please explain why the costs should be paid FEU's ratepayers.

Response:

The FEU note that the costs will be borne by the customers taking the thermal energy service, and not natural gas customers. As with any public utility service, the direct benefits accrue to the customers who are provided with this service, and from whom the costs are recovered under the existing approved rate structures (see the response to BCUC IR 2.131.3). Indirect benefits such as the reduction of greenhouse gas emissions accrue to the greater population. The treatment of costs for 2012 and 2013 are explained in Ex B-1, pages 15-16.

132.0 Reference: Thermal Energy

Exhibit B-1, Appendix G, Section 2.4.2, p. 4

FEU Transfer Pricing Policy

Non Rate Base Deferral Account Cost Allocation

132.1 Please provide the latest copy of the FEU Transfer Pricing Policy.

Response:

The latest copy of the FEU Transfer Pricing Policy is provided in Attachment 132.1.

Table G-2: Thermal Energy Projects are in Development Stages

	2010			2011		
	NSA	Actual	Variance	NSA	Projected	Variance
Direct Costs	-	1,196	1,196	-	11,750	11,750
Sales & Marketing	1,000	1,435	435	1,500	1,550	50
Overhead Allocation	500	500	-	500	500	-
AFUDC	-	82	82	-	100	100
Tax	(428)	(682)	(254)	(530)	(543)	(13)
	1,073	2,530	1,458	1,470	13,357	11,887

"As agreed to in the NSA, these costs were budgeted at $1 million in 2010 and $1.5 million in 2011.

…In Commission Order G-141-09, FEI agreed to charge Alternative Energy Services customers $0.5 million for 2010 and $0.5 million for 2011 for administrative services provided by the gas utility to the alternative energy customers. As part of this application, FEI undertook a review of which services should be included in this administrative charge and what the charge should be for 2012 and 2013."

The NSA includes one method for calculating the costs allocated to the Thermal Energy line of business. The FEU Transfer Pricing Policy and the pricing work performed for Third Parties are two other methods for allocating costs.

132.2 Please recalculate the 2010 and 2011 costs to be allocated to the thermal energy line of business using the FEU Transfer Pricing Policy. Also provide the schedules in fully functional electronic format.

Response:

The thermal energy class of service is a regulated business and as such the transfer pricing policy is not applicable. The $0.5 million overhead allocation was determined by negotiation and represents a fixed allocation of resources that was set for 2010 and 2011. As the allocation was pre-determined, the FEU did not specifically track the actual costs and is unable to provide the calculation as requested. In response to BCUC IR 1.78.1 the FEU did provide a breakdown of 2012 and 2013 estimates. If FEU's transfer pricing policy was applied to the amounts for 2012 and 2013 as calculated in response to BCUC IR 1.78.1, the total charge would increase by 10% for an overhead charge and by $100 per full day equivalent as a facilities charge.

132.3 Please recalculate the 2010 and 2011 costs to be allocated to the thermal energy line of business as if the costs are being charged to a Third Party. Also provide the schedules in fully functional electronic format.

Response:

The FEU interprets the reference in the above question to "pricing work performed for Third Parties" to reference the FEU's third-party billing for operational work (i.e. damage claims, billable alterations). For such third party operational work, a 32.5% overhead rate is applied to labour costs to cover supervision and support activities required.

In the response to BCUC IR 1.78.1, the FEU provided a breakdown of 2012 and 2013 estimates. If FEU's third-party billing policy was applied to the amounts for 2012 and 2013 as calculated in response to that IR, the total charge would increase by 32.5% for only the line items with labour. There would be no facilities charges applied as the third-party billing approach is used for operational work which is typically off-site.

133.0 Reference: Cost of Service

Exhibit B-1, Section 5.2.3.2, p. 140

Vancouver Island Cost of Gas

Table 5.2-2 provides details regarding the components of the projected and forecast cost of gas for Vancouver Island including hedging costs/ (gains).

133.1 Based on the forward prices used for the FEVI 2011 Second Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account which was submitted to the Commission on June 7, 2011, please provide an updated version of Table 5.2-2.

Response:

The table shown below shows the forecast Vancouver Island 2011-2013 Cost of Gas, excluding royalty revenues and GCVA impacts, based on the forward prices used in the FEVI 2011 Second Quarter Report on the Gas Cost Variance Account ("GCVA") and the Rate Stabilization Deferral Account ("RSDA"). The Vancouver Island 2011-2013 Cost of Gas shown below also reflects the allocation of the Mt. Hayes LNG demand charges to the Vancouver Island gas costs as filed in the July 19, 2011 Evidentiary Update to the Application.

Vancouver Island 2011-2013 Cost of Gas Excluding Royalty Revenues and GCVA Impacts

Based on the Five-Day Average Natural Gas Forward Prices at May 18, 19, 20, 23, and 24, 2011

(as Used in the FEVI 2011 Second Quarter Report on the GCVA and RSDA)

	Amounts in $ Thousands		
	2011 Projected	**2012 Forecast**	**2013 Forecast**
Commodity	$ 37,179	$ 48,333	$ 54,215
Transportation Demand Charges	7,266	7,408	7,360
Storage Demand Charges [1]	9,828	9,484	9,434
Hedging Cost / (Gain)	15,347	14,349	11,898
Gas Supply Management Costs	630	663	678
Total Cost of Gas [1]	**$ 70,250**	**$ 80,237**	**$ 83,585**

Notes: 1) Includes Mt. Hayes LNG demand charge

The 2012 and 2013 cost of gas forecasts as provided in the table above, are approximately $110 thousand less and $1.173 million greater than the 2012 and 2013 forecasts (respectively) included in the Application. As described in Section 6.3.1.6 of the Application, the GCVA will accumulate the variances between the actual and the forecast gas costs, for amortization and recovery from, or refund to, sales customers in future rates.

133.2 Please provide the NYMEX natural gas forward prices used to calculate the five-day average forward prices utilized in this most recent quarterly update.

Response:

The table below provides the NYMEX natural gas forward prices as of May 18, 19, 20, 23, and 24, 2011 as used to calculate the five-day average forward prices utilized in the gas cost forecasts within the 2011 Second Quarter gas cost reports.

NYMEX Natural Gas Forward Prices as of May 18, 19, 20, 23, and 24, 2011

	May 18 NYMEX ($US/Mmbtu)	May 19 NYMEX ($US/Mmbtu)	May 20 NYMEX ($US/Mmbtu)	May 23 NYMEX ($US/Mmbtu)	May 24 NYMEX ($US/Mmbtu)	5-Day Average NYMEX ($US/Mmbtu)
Feb-11 (A)	$ 4.427	$ 4.427	$ 4.427	$ 4.427	$ 4.427	$ 4.427
Mar-11 (A)	$ 3.853	$ 3.853	$ 3.853	$ 3.853	$ 3.853	$ 3.853
Apr-11 (A)	$ 4.339	$ 4.339	$ 4.339	$ 4.339	$ 4.339	$ 4.339
May-11 (A)	$ 4.384	$ 4.384	$ 4.384	$ 4.384	$ 4.384	$ 4.384
Jun-11	$ 4.198	$ 4.094	$ 4.230	$ 4.346	$ 4.345	$ 4.243
Jul-11	$ 4.266	$ 4.161	$ 4.290	$ 4.393	$ 4.391	$ 4.300
Aug-11	$ 4.316	$ 4.214	$ 4.340	$ 4.438	$ 4.437	$ 4.349
Sep-11	$ 4.344	$ 4.244	$ 4.367	$ 4.465	$ 4.464	$ 4.377
Oct-11	$ 4.393	$ 4.294	$ 4.414	$ 4.510	$ 4.506	$ 4.423
Nov-11	$ 4.562	$ 4.467	$ 4.576	$ 4.667	$ 4.661	$ 4.587
Dec-11	$ 4.786	$ 4.693	$ 4.794	$ 4.885	$ 4.875	$ 4.807
Jan-12	$ 4.903	$ 4.814	$ 4.911	$ 5.002	$ 4.992	$ 4.924
Feb-12	$ 4.895	$ 4.806	$ 4.902	$ 4.993	$ 4.982	$ 4.916
Mar-12	$ 4.840	$ 4.751	$ 4.843	$ 4.935	$ 4.920	$ 4.858
Apr-12	$ 4.719	$ 4.630	$ 4.709	$ 4.801	$ 4.781	$ 4.728
May-12	$ 4.743	$ 4.655	$ 4.731	$ 4.821	$ 4.799	$ 4.750
Jun-12	$ 4.783	$ 4.694	$ 4.771	$ 4.861	$ 4.838	$ 4.789
Jul-12	$ 4.830	$ 4.743	$ 4.818	$ 4.907	$ 4.883	$ 4.836
Aug-12	$ 4.857	$ 4.772	$ 4.846	$ 4.935	$ 4.911	$ 4.864
Sep-12	$ 4.867	$ 4.782	$ 4.856	$ 4.945	$ 4.921	$ 4.874
Oct-12	$ 4.917	$ 4.832	$ 4.906	$ 4.995	$ 4.970	$ 4.924
Nov-12	$ 5.077	$ 4.994	$ 5.064	$ 5.153	$ 5.122	$ 5.082
Dec-12	$ 5.301	$ 5.219	$ 5.284	$ 5.373	$ 5.344	$ 5.304
Jan-13	$ 5.427	$ 5.346	$ 5.411	$ 5.500	$ 5.470	$ 5.431
Feb-13	$ 5.392	$ 5.312	$ 5.376	$ 5.465	$ 5.435	$ 5.396
Mar-13	$ 5.321	$ 5.241	$ 5.301	$ 5.390	$ 5.357	$ 5.322
Apr-13	$ 5.091	$ 5.011	$ 5.061	$ 5.150	$ 5.107	$ 5.084
May-13	$ 5.108	$ 5.029	$ 5.079	$ 5.170	$ 5.125	$ 5.102
Jun-13	$ 5.146	$ 5.067	$ 5.117	$ 5.210	$ 5.165	$ 5.141
Jul-13	$ 5.191	$ 5.112	$ 5.159	$ 5.252	$ 5.203	$ 5.183
Aug-13	$ 5.219	$ 5.142	$ 5.189	$ 5.287	$ 5.235	$ 5.214
Sep-13	$ 5.229	$ 5.152	$ 5.199	$ 5.297	$ 5.245	$ 5.224
Oct-13	$ 5.281	$ 5.204	$ 5.251	$ 5.349	$ 5.294	$ 5.276
Nov-13	$ 5.426	$ 5.349	$ 5.396	$ 5.494	$ 5.439	$ 5.421
Dec-13	$ 5.656	$ 5.579	$ 5.626	$ 5.724	$ 5.669	$ 5.651

Notes: (A) NYMEX three day average closing settlement price.

134.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Appendix I, pp. 10-12

Revenues from NGV Initiatives

134.1 Please quantify the extent to which the Delivery Margin Revenue from CNG/LNG Service in Table I-8 and the Fueling Service Contract Revenue in Table I-10 of the Application is attributed to deliveries of CNG and LNG Service over and above the minimum "take-or-pay" revenue.

Response:

FEI has determined CNG/LNG Service revenues using the minimum "take-or-pay" volume commitment. That is, there are no delivery margin revenues attributed to CNG and LNG Service over and above the minimum take-or-pay volume included in the revenue requirement and Table I-8. The CNG and LNG Costs and Recoveries deferral account will capture recoveries associated with volume in excess of minimum contract demand.

135.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 2, p. 3

IMC 6000 Mobile LNG Station

"Offering CNG and LNG Services requires modest investments in fueling infrastructure, the cost of which is to be recovered through contractual rates charged to the fleet customer. Such investments are only made by FEI if service agreements are executed with the customer, filed with and approved by the Commission as proposed in the NGV Application."

135.1 Please confirm that FEI owns a mobile LNG station which goes by the trade name of an IMC 6000. If FEI does own this unit,

<u>Response:</u>

This response also addresses BCUC IRs 2.135.1.1 through 2.135.1.5.

On July 12, 2011 FEI submitted an Application to the Commission seeking approval of a daily charge for a mobile LNG refuelling station, amongst other approvals sought. The application is before the Commission at this time.

The Company confirms the ownership of a mobile LNG station known as IMC 6000. The equipment has been received but is still pending successful commissioning and performance testing. As discussed in the July 12, 2011 Application, this unit was purchased in December of 2010 at a capital cost of $428,000 to provide LNG refuelling to a potential fleet customer. The LNG supply agreements were not completed with this customer due to delays incurred while FEI sought clarification of regulatory issues associated with providing EEC incentives for NGVs. However, FEI has found a short term use for this asset. The IMC 6000 is scheduled to be deployed at the site of Vedder Transport, a heavy duty trucking fleet operator who has purchased 50 LNG vehicles, on a temporary basis until the Vedder permanent station is in place, as approved by BCUC Order No. G-144-11. Over the long term, FEI foresees a few potential alternatives for the asset which include:

1) Use at the customer's site for which it was originally purchased;
2) Use at another NGV customer's site as a permanent solution;
3) Use as a backup system resource to fuel existing gas customers and/or NGV customers.

A decision on which alternative to pursue will be made at the conclusion of the temporary service agreement period with Vedder. Once a decision on which alternative to pursue is known the treatment of this asset will be confirmed.

At this time the asset is anticipated to be placed into service and rate base during 2011 and is not impaired as the Company expects to fully recover the cost of the asset through rates over its useful life. The IMC 6000 will be captured in asset class 476-20 (LNG Dispensing Equipment) and will be depreciated at a rate of 5%, consistent with the depreciation rate for LNG Dispensing Equipment approved in Commission Order No. G-128-11.

135.1.1 When was this unit purchased?

Response:

Please see our response to BCUC IR 2.135.1.

135.1.2 What was the capital cost of the unit?

Response:

Please see our response to BCUC IR 2.135.1.

135.1.3 Is this asset in rate base?

Response:

Please see our response to BCUC IR 2.135.1.

135.1.4 Is this asset currently impaired?

Response:

Please see our response to BCUC IR 2.135.1.

135.1.5 What is the depreciation rate that applies to this asset and how was it determined?

Response:

Please see our response to BCUC IR 2.135.1.

136.0 Reference: Natural Gas Vehicles

Exhibit B-1, Part 1.2.3.2, pp. 13-14 and Appendix I, pp.

Order G-128-11

Impact of Order G-128-11

"On December 1, 2010 FEI submitted its Application for Approval of a Service Agreement for CNG Service and for Approval of General Terms and Conditions ("GT&Cs") for CNG and LNG Service (the "NGV Application") to the Commission." (B-1, p. 13)

"The forecasts made in relation to NGVs and NGV fueling infrastructure in this Application and in Appendix I are premised on the assumption that the NGV Application will be approved as filed and all approvals sought will be granted." (B-1, p. 14)

"**Table I-11: O&M Cost Estimate for 2010 and 2011**

Department or Activity	2010		2011	
	FTE	Cost Estimate	FTE	Cost Estimate
Business Development Managers	1.3	$ 148,836	1.3	$ 156,241
Energy Products and Service Manager, Commercial & Industrial Sales, Project Manager	2.7	$ 331,439	2.7	$ 345,396
Customer Education	N/A	$ -	N/A	$ 50,000
Total:	**4.0**	**$ 480,275**	**4.0**	**$ 551,637**

"All O&M amounts related to NGV have been appropriately included in the overall O&M forecast for all of our core gas business. The estimates provided in Table I-11 are ***included here only for informational purposes*** *with the intention of providing an order-of magnitude of the impact of NGV activities on our O&M*." [Bold and underlined for emphasis] (Exhibit B-1, Appendix I, p. 15)

136.1 Please provide the impact of Order G-128-11 on the Application (revenue, O&M, capital additions, depreciation, and headcount).

Response:

This response also addresses BCUC IR 2.136.2.

As discussed in the Application (Exhibit B-1) in Section 1.2.3.2, the 2012 and 2013 CNG and LNG Service forecasts are premised on the assumption that the cost-effective EEC incentives for NGVs will continue during the test period. As a result, FEI is in the process of evaluating the impacts of BCUC Order No. G-128-11 and the Commission's recent Decision on NGV incentives (issued August 15, 2011 through BCUC Order No. G-145-11) and the resulting changes required to the revenue requirement forecasts and financial schedules for 2012 and 2013.

FEU anticipates filing its second Evidentiary Update to reflect both of these decisions along with its request for interim rates prior to October 1, 2011, as directed by Commission Order No. G-129-11.

"FEI was not required to track and report actual amounts for NGV separately during this period 2010-2011 period. These cost estimates do not include time for regulatory activities such as cost of service modelling, NGV Application support and review. FEI estimates a minimal customer education cost will be incurred in 2011 for NGV." (Exhibit B-1, Appendix I, p. 14)

136.2 Please provide the specific impact of Order G-128-11 on cost of service modeling, NGV Application support, review and customer education on the Application.

Response:

Please see our response to BCUC IR 2.136.1.

137.0 Reference: Support for Details of Rate Changes for 2012

Exhibit B-9, BCUC IR 1.126.1, pp. 414-419

Exhibit B-1, Tab 7.2, Schedule 82

Exhibit B-1, Tabs 7.1-7.4, Schedule 1

Discrepancies

137.1 The amount ($13.0 million) in column 3, row 61 (Depreciation from Net Additions for FEI) on Attachment 126.1a on p. 415 of the BCUC IR1.126.1 response does not agree with the amount on Tab 7.1, Schedule 1 ($12.9 million). This difference results in a discrepancy in the Revenue Deficiency (Surplus) of $100,000. Please revise the schedule if appropriate or provide an explanation for the difference.

Response:

The cause of this variance is a rounding discrepancy and a revision to the schedules is not required. The $100,000 difference between Tab 7.1, Schedule 1 ($12.9 million) and Attachment 126.1a on p. 415 of the BCUC IR1 126.1 response ($13.0 million) is from the rounding of the 'Change in Depreciation' on Tab 7.1, Schedule 1 to one decimal place. The overall impact on the Deficiency (Surplus) is zero as the rounding only moved $40,000 of the 'Depreciation from Net Additions' variance into the 'Change in Depreciation' variance. The total Deficiency (Surplus) in both schedules questioned tie to the Deficiency (Surplus) in Schedule 2 from the filing.

Table 1 is an excerpt from the May 4 filing showing 3 decimal places and the impact of rounding the Change in Depreciation.

Table 1

Excerpt from: Section 7, Tab 7.1, Schedule 1 - showing 3 decimal places

Line	Particulars	May 4, 2011 Filing 2012 ($ Millions)		Change in Depreciation unrounded 2012 ($ Millions)	
	(1)	(2)	(3)	(4)	(5)
	Depreciation & Removal Cost Provision				
1	Change in Depreciation Rates	4.600		4.560	
2	Tax Expense Impact of Depreciation Changes	7.482		7.482	
3	Depreciation from Net Additions	12.937		12.977	
4	Removal Cost Provision	4.908	29.927	4.908	29.927

Variance moved from (Line 1 Column 2) to (Line 3 Column 4) after rounding removed.
Total Variance (Line 4 Column 3) and (Line 4 Column 5) is equal

Table 2 is an excerpt from Tab 7.1, Schedule 1 from the July 19 Evidentiary Update and the impact of rounding the Change in Depreciation.

Table 2

Excerpt from: Section 7, Tab 7.1, Schedule 1 - showing 3 decimal places

Line	Particulars	Evidentiary Update - July 19, 2011 2012 ($ Millions)		Change in Depreciation unrounded 2012 ($ Millions)	
	(1)	(2)	(3)	(4)	(5)
	Depreciation & Removal Cost Provision				
1	Change in Depreciation Rates	4.600		4.560	
2	Tax Expense Impact of Depreciation Changes	7.674		7.674	
3	Depreciation from Net Additions	13.511		13.551	
4	Removal Cost Provision	4.912	30.697	4.912	30.697

Variance moved from (Line 1 Column 2) to (Line 3 Column 4) after rounding removed.
Total Variance (Line 4 Column 3) and (Line 4 Column 5) is equal

137.2 The amount in column 4, row 130 of Attachment 126.1a (Approved Long Term Debt 2011 for FEVI) does not agree with the amount of $365.5 million shown on Schedule 82, as per the cross reference. The difference is $(25.2) million. The column 4, row 132 (Approved Long Term Debt Rate 2011 for FEVI) also does not agree with the rate of 5.70 % shown on Schedule 82, as per the cross reference. In addition on Schedule 1 in Tab 7.2 of Exhibit B-1, the total for 2012 O&M Changes adds to $2.1 million instead of $2.2 million. Given these discrepancies, it would appear that the Long Term Debt Financing Changes on column 4, row 133 should be $nil, the Financing Changes on column 5, row 140 should be $2.9 million, and the Revenue Deficiency (Surplus) on column 5, row 150 should be $1.5 million. These differences result in the same difference for Schedule 1 in Tab 7.2 of Exhibit B-1. Please revise the schedule if appropriate or provide an explanation for the difference.

Response:

Revised schedules are not required. The three discrepancies noted in the question are discussed in further detail below:

- The reference for Row 130 Attachment 126.1a (Approved Long Term Debt 2011) should read "FEI, FN and FEW Schedule 82, FEVI Schedule 73 2010-2011 Approved RRA". The 2011 long-term debt for FEVI in the 2010-2011 Approved RRA was $390.7 million and, therefore, the amount shown in Attachment 1.126.1a is correct.

- The reference for Row 132 Attachment 126.1a (Approved Long Term Debt Rate 2011) should read "FEI, FN and FEW Schedule 82, FEVI Schedule 73 2010-2011 Approved RRA)". Approved long term debt from the FEVI 2010-2011 RRA filing is $390.731 million and the Average Embedded cost from the 2010-2011 RRA Filing is 6.12% which matches Row 132 of Attachment 126.1a. The 5.70% referenced in this IR is the projected 2011 Average Embedded cost as filed in the 2012-2013 Revenue Requirement Application.

- Schedule 1, Tab 7.2 of Exhibit B-1 'O&M Changes' for 2012 is correct as displayed. The perceived difference is from the display of decimals. The 'O&M Changes' numbers from Schedule 1 are not rounded, but are displayed at 1 decimal place. Please refer to the following two tables which demonstrate that Schedule 1 is correct as displayed.

Table 1 is an excerpt from the May 4, 2011 filing with 3 decimals places displayed showing that the summation is correct.

Table 1

Summary of Rate Change				May 4, 2011
Vancouver Island				
	2012 ($ Millions)		**2013 ($ Millions)**	
O&M Changes				
Gross O&M Increases	2.534		0.246	
Less: Capitalized Overhead	(0.366)	2.168	(0.034)	0.212

Table 2 is an excerpt from the Evidentiary Update filing of July 19, 2011 with 3 decimals places displayed showing that the summation is correct.

Table 2

Summary of Rate Change				Evidentiary Update - July 19, 2011
Vancouver Island				
	2012 ($ Millions)		**2013 ($ Millions)**	
O&M Changes				
Gross O&M Increases	3.415		0.115	
Less: Capitalized Overhead	(0.490)	2.925	(0.016)	0.099

137.3 The amount ($1.8 million) in column 5, row 105 (Financing Rate Changes for FEVI) on Attachment 126.1b on p. 419 of the BCUC IR1.126.1 response does not agree with the 2013 amount on Tab 7.2 Schedule 1 ($1.7 million). In addition, the 2013 Depreciation & Removal Cost Provision on Schedule 1 on Tab 7.2 of Exhibit B-1, adds to $1.6 million instead of $1.7 million. These differences result in a discrepancy in the Revenue Deficiency (Surplus) of $(100,000). These differences plus the differences noted in the IR above, results in differences in the total 2012 and 2013 amounts. Overall, the impact to the total 2012 and 2013 Revenue Deficiency (Surplus) is $1.4 million. Please revise the schedule if appropriate or provide an explanation for the difference.

Response:

Revisions to the schedules are not required.

The variance breakdowns in Schedule 1, Tab 7.2 of Exhibit B-1 of the May 4 filing and in Attachment 126.1b on p. 419 of the BCUC IR1.126.1 response are not used to calculate the revenue deficiency (surplus). The two analyses are monetizing the impacts of key drivers on the revenue deficiency (surplus) and to explain the change in the revenue requirement. Therefore, regardless of how these two schedules categorize or calculate the drivers, the revenue deficiency (surplus) will not change.

- Schedule 1, Tab 7.2 of Exhibit B-1 calculates the 2012 variances using 2012 data then calculates Total variance (2012 & 2013) using the accumulated total data. The 2013 variances are calculated by subtracting the 2012 variances from the Total variances.
- Based on BCUC IR1.126.1, Attachment 126.1b on p. 419 of the BCUC IR1.126.1 response quantifies the 2012 and 2013 variances exclusive of each other and therefore, in some cases, has resulted in slightly different values.

The '2013 Financing Rate Change' from Schedule 1, Tab 7.2 of Exhibit B-1 should read $1.8 million as it shows on Row 105 of Attachment 126.1b on p. 419 of the BCUC IR1.126.1. Please refer to the Evidentiary Update dated July 19, 2011 where Schedule 1, Tab 7.2 shows $1.8 million.

138.0 Reference: Financial Schedules

Exhibit B-1, Tab 7.1-Mainland

Discrepancies in Various Schedules

For the following discrepancies, please revise the schedules if the amounts are indeed incorrect or provide an explanation for the difference.

138.1 In Schedule 1, the amounts under 2013 do not add to the sub-totals and totals shown on this schedule. O&M Changes should total $10.7 million, Amortization Expense should total $12.4 million, and Revenue Deficiency (Surplus) should total $37.0 million. This difference results in a discrepancy in the Revenue Deficiency (Surplus) of $200,000 for 2013 and the combined effect of the above IR and this IR is a difference of $100,000 in the Total Revenue Deficiency (Surplus) for 2012 and 2013.

Response:

The referenced Schedule 1 is not incorrect, but rather does not add due to rounding within the sub-total amounts. The Total Revenue Deficiency of $36.8 million is correct and can be found in detail in Section 7, Tab 7.1, Schedule 3, Column 7 of the 2012-2013 Revenue Requirements Application. To demonstrate the rounding within the sub-totals, the two amounts referenced in this IR are broken out to the nearest thousand below:

	2013 ($ Thousands)	
O&M Changes		
Gross O&M Increases	$ 12,353	
Less: Capitalized Overhead	$ (1,729)	$ 10,624
Amortization Expense		
CIAC	$ 58	
Deferral Accounts	$ 12,259	$ 12,317

138.2 In Schedules 4, 5 and 6 row 18 does not appear to be included in the summation of "Total Revenue", as the totals do not agree to the "Total Revenue" stated on each of these schedules.

Response:

Please refer to the Evidentiary Update filed on July 19, 2011. The amount in row 18 for Schedules 4, 5, and 6, as filed on May 4, 2011, should not have been displayed. This row is not applicable to FEI financial schedules and is not included in the determination of the revenue requirement. This formatting error was amended in the Evidentiary Update. However, although included in the determination of total revenue, row 14 (RSAM Revenue) of Schedule 5 was hidden in Section 7.1 of both the May 4th and July 19th submissions.

Please see an amended Schedule 5 for FEI below, updated to display row 14 (RSAM Revenue):

FORTISBC ENERGY INC. - Mainland

Section 7
TAB 7.1
Schedule 5

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 ------ Revised Rates ------- Revised Revenue	2012 ------ Revised Rates ------- Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (2))	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,632	112,458	-	112,458	(174)	- Sect 7-TAB 7.1, Schedule 8
3	Transportation	93,355	94,258	-	94,258	903	- Sect 7-TAB 7.1, Schedule 8
4		205,987	206,716	-	206,716	729	
5							
6	Average Rate per GJ						
7	Sales	$ 10.067	$ 10.077	$ -	$ 10.304	$ 0.237	
8	Transportation	$ 0.873	$ 0.879	$ -	$ 0.920	$ 0.047	
9	Average	$ 5.886	$ 5.883	$ -	$ 6.025	$ 0.139	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,133,872	$ 1,133,246	$ -	$ 1,133,246	$ (626)	- Sect 7-TAB 7.1, Schedule 11
13	- Increase / (Decrease)	-	-	25,552	25,552	25,552	- Sect 7-TAB 7.1, Schedule 14
14	RSAM Revenue	(2,859)				2,859	
15	Transportation - Existing Rates	81,463	82,894	-	82,894	1,431	- Sect 7-TAB 7.1, Schedule 11
16	- Increase / (Decrease)	-		3,810	3,810	3,810	- Sect 7-TAB 7.1, Schedule 14
17							
18	**Total Revenue**	1,212,476	1,216,140	29,365	1,245,505	33,029	
19							
20	Cost of Gas Sold (Including Gas Lost)	661,224	659,338	-	659,338	(1,886)	- Sect 7-TAB 7.1, Schedule 13
21							
22	**Gross Margin**	551,252	556,802	29,365	586,167	34,915	
23							
24	Operation and Maintenance	184,625	198,074	-	198,074	13,449	- Sect 7-TAB 7.1, Schedule 21
25	Property and Sundry Taxes	50,211	49,656	-	49,656	(555)	- Sect 7-TAB 7.1, Schedule 25
26	Depreciation and Amortization	100,729	127,123	-	127,123	26,394	- Sect 7-TAB 7.1, Schedule 28
27	NSP Provisions	1,025	-	-	-	(1,025)	
28	Other Operating Revenue	(23,432)	(27,203)	-	(27,203)	(3,771)	- Sect 7-TAB 7.1, Schedule 19
29	Sub-total	313,158	347,650	-	347,650	34,492	
30	Utility Income Before Income Taxes	238,094	209,152	29,365	238,517	423	
31							
32	Income Taxes	31,330	17,250	7,340	24,590	(6,740)	- Sect 7-TAB 7.1, Schedule 31
33							
34	**EARNED RETURN**	$ 206,764	$ 191,902	$ 22,025	$ 213,927	$ 7,163	- Sect 7-TAB 7.1, Schedule 80
35							
36							
37	**UTILITY RATE BASE**	$ 2,535,461	$ 2,740,462	$ 350	$ 2,740,812	$ 205,351	- Sect 7-TAB 7.1, Schedule 40
38							
39	**RATE OF RETURN ON UTILITY RATE BASE**	8.15%	7.00%		7.81%	-0.34%	- Sect 7-TAB 7.1, Schedule 80

138.4 In Schedule 48, some of the amounts for Mid-Year GPIS for Depreciation in column 10 do not appear to be correct, as when the Mid-Year GPIS for Depreciation is determined for "Total Capital" in row 42, the amount computed does not equal the stated amount. Per Schedule 48, the Mid-Year GPIS for Depreciation for the "Total Capital" is $3,718,759 compared to $3,656,234 [($3,542,280 (column 2, row 42) + $3,770,188 (column 9, row 42))/2]. Please revise if the amounts are incorrect or if the amounts are correct, please explain the difference.

Response:

The Mid-Year GPIS for Depreciation amounts, as shown in Column 10 of Schedules 43-51, represents the mid-year balance of the account and also an adjustment for the timing of the in-service date of CPCN projects. Therefore, in some cases, the balance used to determine depreciation may not be the opening balance plus closing balance, divided by two as described in the question. Rather, the balance used to determine depreciation is opening balance plus closing balance, divided by two plus the thirteen month adjustment.

FEI acknowledges that the mid-year balance as displayed in column 10 on Schedule 48 is incorrect. An error in the presentation of the balances in Column 10 of Schedule 48 occurred because of an incorrect adjustment for the in-service date of the CCE and Tilbury Property Purchase CPCN related expenditures. Therefore, the correct calculation for the Total Mid-Year GPIS for Depreciation on Schedule 48 Column 10 Row 42 is ($3,542,282 + $3,771,060)/2 + $40,567 = $3,697,238 as shown in Schedule 48 below. The $40,567 is the 13 month adjustment found on Schedule 40 Column 3 Row 22.

This error was limited only to the presentation of the balance on this schedule; that is, the calculation basis for depreciation expense is not impacted by this error. A revised Schedule 48, providing the correct Mid-Year GPIS for Depreciation balance in Column 10, is provided below as well as Schedules 46 and 47:

FORTISBC ENERGY INC. - Mainland

Evidentiary Update - July 19, 2011

Section 7
TAB 7.1
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,167	-	325	-	-	-	-	44,492	44,330
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	-	-	-	-	-	-	1,211	1,211
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	40,420	50,225	5,400	140	-	(2,722)	-	93,463	92,054
17	402-02 Application Software - 20%	16,878	-	5,400	81	-	(1,949)	-	20,410	18,644
18	TOTAL INTANGIBLE	105,154	50,225	11,125	221	-	(4,671)	-	162,054	158,717
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	146	-	50	-	18	-	-	214	180
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmei	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	14,112	-	-	-	-	-	15,040	15,040
30	442-00 Structures & Improvements (Tilbury)	4,959	588	-	-	-	-	-	5,547	5,529
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,669	-	2,050	63	732	(681)	-	28,833	27,751
36	TOTAL MANUFACTURED	50,411	14,700	2,100	63	750	(681)	-	67,343	66,209

FORTISBC ENERGY INC. - Mainland

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Section 7
TAB 7.1
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	212	-	-	-	-	-	-	212	212
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	14,729	-	-	-	-	-	-	14,729	14,729
6	463-00 Measuring Structures	5,380	-	-	-	-	-	-	5,380	5,380
7	464-00 Other Structures & Improvements	6,014	-	-	-	-	-	-	6,014	6,014
8	465-00 Mains	785,028	1,223	22,196	928	7,924	(1,065)	-	816,234	800,631
9	465-00 Mains - INSPECTION	4,089	-	1,531	-	547	-	-	6,167	5,128
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	110,564	-	4,021	191	1,436	(547)	-	115,665	113,115
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	-	-	-	-	-	-	28,208	28,208
17	467-20 Telemetering	6,574	-	736	32	263	(481)	-	7,124	6,849
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	971,841	1,223	28,484	1,151	10,170	(2,093)	-	1,010,776	991,309
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,414	-	-	-	-	-	-	3,414	3,414
25	471-00 Distribution Land Rights	-	-	50	-	-	-	-	50	25
26	472-00 Structures & Improvements	15,643	-	-	-	-	-	-	15,643	15,643
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	683,648	-	16,950	-	6,052	(2,947)	-	703,703	693,676
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	150,452	-	242	-	87	(1,783)	-	148,998	149,725
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	-	-	11,074	-	3,954	-	-	15,028	7,514
33	475-00 Mains	893,381	-	23,037	177	8,225	(2,834)	-	921,986	907,684
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	86,954	-	2,930	139	1,046	(542)	-	90,527	88,741
37	477-00 Telemetering	6,478	-	650	5	232	(120)	-	7,245	6,862
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	199,797	-	11,316	-	-	(3,915)	-	207,198	203,498
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,161,402	-	66,249	321	19,596	(12,141)	-	2,235,427	2,198,415
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	140	-	-	-	-	140	70
47	475-10 Bio Gas Mains – Municipal Land	-	-	109	-	38	-	-	147	74
48	475-20 Bio Gas Mains – Private Land	183	-	61	-	22	-	-	266	225
49	418-10 Bio Gas Purification Overhaul	402	-	413	-	-	-	-	815	609
50	418-20 Bio Gas Purification Upgrader	1,607	-	1,650	-	-	-	-	3,257	2,432
51	477-10 Bio Gas Measuring & Regulating Equipment	627	-	679	-	242	-	-	1,548	1,088
52	478-30 Bio Gas Meters	765	-	25	-	-	-	-	790	778
53	TOTAL BIO-GAS	3,584	-	3,077	-	302	-	-	6,963	5,274

FORTISBC ENERGY INC. - Mainland

Section 7
TAB 7.1
Schedule 48

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,048	$ -	$ 1,540	$ -	$ 550	$ -	$ -	$ 4,138	$ 3,093
3	476-20 NG Transportation LNG Dispensing Equipment	1,743	-	1,180	-	421	-	-	3,344	2,544
4	476-30 NG Transportation CNG Foundations	452	-	340	-	121	-	-	913	683
5	476-40 NG Transportation LNG Foundations	384	-	260	-	93	-	-	737	561
6	476-50 NG Transportation LNG Pumps	827	-	560	-	200	-	-	1,587	1,207
7	476-60 NG Transportation CNG Dehydrator	160	-	120	-	43	-	-	323	242
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,614	-	4,000	-	1,428	-	-	11,042	8,328
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	20,271	-	2,000	-	-	-	-	22,271	21,271
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	7,892	-	-	-	-	-	-	7,892	7,892
16	- Masonry Buildings	86,083	7,245	3,777	-	-	-	-	97,105	95,217
17	- Leasehold Improvement	261	3,058	80	-	-	-	-	3,399	3,359
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,572	332	507	-	-	-	-	4,411	4,158
20	483-40 GP Furniture	19,393	2,459	1,536	-	-	(567)	-	22,821	22,337
21	483-10 GP Computer Hardware	20,875	3,151	7,200	192	-	(1,517)	-	29,901	26,964
22	483-20 GP Computer Software	1,820	-	-	-	-	(475)	-	1,345	1,583
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	1,282	-	465	-	-	(14)	-	1,733	1,508
26	484-00 Vehicles - Leased	28,481	-	3,180	-	-	(1,908)	-	29,753	29,117
27	485-10 Heavy Work Equipment	270	-	-	-	-	-	-	270	270
28	485-20 Heavy Mobile Equipment	1,023	-	200	-	-	-	-	1,223	1,123
29	486-00 Small Tools & Equipment	40,702	-	3,009	-	-	(884)	-	42,827	41,765
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,783	-	115	-	-	-	-	7,898	7,841
34	- Radio	4,544	-	45	-	-	(7)	-	4,582	4,563
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	244,276	16,245	22,114	192	-	(5,372)	-	277,455	268,988
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,542,282	$ 82,393	$ 137,149	$ 1,948	$ 32,246	(24,958)	$ -	$ 3,771,060	$ 3,697,238

138.5 The subtotals and grand total in column 2 of Schedule 61 do not add to the subtotals and total shown on this schedule. The sub-totals and totals do, however, agree to respective totals on Schedules 46- 48. Please revise if the amounts are incorrect or if the amounts are correct, please explain the difference. The differences are as follows:

($000s)	Per Schedule 61	Per Commission Staff	Difference
Total Manufactured Column 2, row 5	$58,857	$49,478	$9,379
Total Transmission Column 2, row 15	$991,133	$968,260	$22,873
Total Distribution Column 2, row 28	$2,197,924	$2,142,459	$55,465
Total Bio-Gas Column 2, row 33	$5,562	$567	$4,995
Totals Column 2, row 35	$3,718,759	$3,160,764	$557,995

Other differences:

($000s)	Per Schedule 61	Per Commission Staff	Difference
Total Distribution Column 4, row 28	$14,471	$14,415	$56
Total Distribution Column 9, row 28	$6,267	$6,211	$56
Totals Column 4, row 35	$16,198	$16,142	$56
Totals Column 9, row 35	$7,994	$7,938	$56

Response:

This response also applies to BCUC IR 2. 138.6.

Revised versions of Schedules 61 and 62 are provided below, with the totals in column 2 corrected and Rows 23 and 24 unhidden. The tables below reflect the Evidentiary Update filed

July 19th. In the Evidentiary Update Rows 23 and 24 shown below were inadvertently hidden. The subtotal in Column 4 of $14,472 is still the correct amount. The incorrect totals (Column 2) did not carry forward to any other financial schedules, and therefore did not affect any of the revenue requirement or rate calculations.

FORTISBC ENERGY INC. - Mainland

Section 7
TAB 7.1
Schedule 61

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 5,547	0.36%	$ 19	$ -	$ -	$ -	$ -	$ 19
3	443-00 Gas Holders - Storage (Tilbury)	16,494	0.40%	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	27,751	0.37%	103	-	-	-	-	103
5	TOTAL MANUFACTURED	49,792		188	-	-	-	-	188
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	14,729	0.18%	27	-	-	-	-	27
9	463-00 Measuring Structures	5,380	0.18%	10	-	-	-	-	10
10	464-00 Other Structures & Improvements	6,014	0.14%	8	-	-	-	-	8
11	465-00 Mains	800,631	0.14%	1,121	-	-	-	-	1,121
12	466-00 Compressor Equipment	113,115	0.28%	317	-	-	-	-	317
13	467-10 Measuring & Regulating Equipment	28,208	0.18%	51	-	-	-	-	51
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	-	3
15	TOTAL TRANSMISSION	968,423		1,537	-	-	-	-	1,537
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	15,643	0.16%	25	-	-	-	-	25
19	473-00 Services	693,676	1.07%	7,422	-	(9,209)	-	-	(1,787)
20	473-00 Services - LILO	43,024	2.86%	1,230	-	-	-	-	1,230
22	474-00 House Regulators & Meter Installations	149,725	0.75%	1,123	5,451	(2,700)	-	-	3,874
23	474-00 House Regulators & Meter Installations - LILO	16,070	0.00%	-	-	-	-	-	-
24	477-00 Meters/Regulators Installations	7,514	0.75%	56	-	-	-	-	56
25	475-00 Mains	907,684	0.29%	2,632	-	(700)	-	-	1,932
26	475-00 Mains - LILO	39,717	0.98%	389	-	-	-	-	389
27	476-00 Compressor Equipment	1,026	11.43%	117	-	-	-	-	117
28	477-00 Measuring & Regulating Equipment	88,741	0.52%	461	-	-	-	-	461
29	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	-	-	-
30	478-10 Meters	203,498	0.50%	1,017	(1,046)	-	-	-	(29)
31	TOTAL DISTRIBUTION	2,166,479		14,472	4,405	(12,609)	-	-	6,268
32									
33	**BIO GAS**								
34	475-20 Bio Gas Mains – Private Land	225	0.29%	1	-	-	-	-	1
35	478-30 Bio Gas Meters	778	0.50%	4	-	-	-	-	4
36	TOTAL BIO-GAS	1,002		5	-	-	-	-	5
37									
38	TOTALS	$ 3,185,696		$ 16,202	$ 4,405	$ (12,609)	$ -	$ -	$ 7,998
39									
40	Cross Reference			- Sect 7-TAB 7.1, Schedule 28				- Sect 7-TAB 7.1, Schedule 40	
41									

FORTISBC ENERGY INC. - Mainland

Section 7
TAB 7.1
Schedule 62

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision: Provision (Cr.)	Provision: Adjust-ments	Provision: Removal Costs	Provision: Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 5,547	0.36%	$ 20	$ -	$ -	$ -	$ 19	$ 39
3	443-00 Gas Holders - Storage (Tilbury)	16,494	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	29,074	0.37%	108	-	-	-	103	211
5	TOTAL MANUFACTURED	51,115		194	-	-	-	188	382
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	14,729	0.18%	27	-	-	-	27	54
9	463-00 Measuring Structures	5,380	0.18%	10	-	-	-	10	20
10	464-00 Other Structures & Improvements	6,014	0.14%	8	-	-	-	8	16
11	465-00 Mains	829,019	0.14%	1,161	-	-	-	1,121	2,282
12	466-00 Compressor Equipment	117,827	0.28%	330	-	-	-	317	647
13	467-10 Measuring & Regulating Equipment	28,208	0.18%	51	-	-	-	51	102
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
15	TOTAL TRANSMISSION	1,001,523		1,590	-	-	-	1,537	3,127
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	15,643	0.16%	25	-	-	-	25	50
19	473-00 Services	715,127	1.07%	7,652	-	(9,232)	-	(1,787)	(3,367)
20	473-00 Services - LILO	43,024	2.86%	1,230	-	-	-	1,230	2,460
22	474-00 House Regulators & Meter Installations	148,986	0.75%	1,117	-	(2,700)	-	3,874	2,291
23	474-00 House Regulators & Meter Installations - LILO	16,070	0.00%	-	-	-	-	-	-
24	477-00 Meters/Regulators Installations	22,917	0.75%	172	-	-	-	56	228
25	475-00 Mains	939,374	0.29%	2,724	-	(1,000)	-	1,932	3,656
26	475-00 Mains - LILO	39,717	0.98%	389	-	-	-	389	778
27	476-00 Compressor Equipment	1,026	11.43%	117	-	-	-	117	234
28	477-00 Measuring & Regulating Equipment	92,367	0.52%	480	-	-	-	461	941
29	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	-	-	-
30	478-10 Meters	211,085	0.50%	1,055	-	-	-	(29)	1,026
31	TOTAL DISTRIBUTION	2,245,498		14,961	-	(12,932)	-	6,268	8,297
32									
33	**BIO GAS**								
34	475-20 Bio Gas Mains – Private Land	308	0.29%	1	-	-	-	1	2
35	478-30 Bio Gas Meters	803	0.50%	4	-	-	-	4	8
36	TOTAL BIO-GAS	1,111		6	-	-	-	5	11
37									
38	TOTALS	$ 3,299,246		$ 16,751	$ -	$ (12,932)	$ -	$ 7,998	$ 11,817
39									
40	Cross Reference			- Sect 7-TAB 7.1, Schedule 29				- Sect 7-TAB 7.1, Schedule 41	
41									

138.6 The subtotals and grand total in column 2 of Schedule 62 do not add to the subtotals and total shown on this schedule. The sub-totals and totals do, however, agree to respective totals on Schedules 49- 51. Please revise if the amounts are incorrect or if the amounts are correct, please explain the difference. The differences are as follows:

($000s)	Per Schedule 62	Per Commission Staff	Difference
Total Manufactured Column 2, row 5	$67,553	$51,085	$16,468
Total Transmission Column 2, row 15	$1,026,614	$1,001,169	$25,445
Total Distribution Column 2, row 28	$2,277,192	$2,205,713	$71,479
Total Bio-Gas Column 2, row 33	$9,107	$1,249	$7,858
Totals Column 2, row 35	$3,837,558	$3,259,216	$578,342

Other differences:

($000s)	Per Schedule 62	Per Commission Staff	Difference
Total Distribution Column 4, row 28	$14,956	$14,785	$171
Totals Column 4, row 35	$16,743	$16,572	$171
Total Distribution Column 8, row 28	$6,267	$6,211	$56
Totals Column 8, row 35	$7,994	$7,938	$56
Total Distribution Column 9, row 28	$8,291	$8,064	$227
Totals Column 9, row 35	$11,805	$11,578	$227

<u>Response:</u>

Please see response to BCUC IR 2.138.5.

139.0 Reference: Financial Schedules

Exhibit B-1, Tab 7.2- Vancouver Island

Discrepancies in Various Schedules

For the following discrepancies, please revise the schedules if the amounts are indeed incorrect or provide an explanation for the difference.

139.1 There appears to be a number of adding errors on Schedules 7-9. While the Total Sales on row 11, Total Transportation Service on row 18, and Total Sales and Transportation Services on row 20 agree to the amounts on Schedules 4-6, respectively, as per the cross-reference, the amounts presented on Schedules 7-9 do not add to these totals. The differences are as follows:

	Per Schedule 7	Per Commission Staff	Difference
Residential & Commercial Column 2, row 6	11,256.7	7,818.6	3,438.1
Residential & Commercial Column 3, row 6	12,179.7	8,829.3	3,350.4
Residential & Commercial Columns 4 and 6, row 6	11,522.3	7,921.3	3,601
Residential & Commercial Column 7, row 6	(657.4)	(908.0)	(250.6)
Total Sales Column 2, row 11	11,491.4	8,053.3	3,438.1
Total Sales Column 3, row 11	12,432.6	9,082.2	3,350.4
Total Sales Columns 4 and 6, row 11	11,695.6	8,094.6	3,601
Total Sales Column 7, row 11	(737.9)	(987.6)	249.7
Total Sales and Transportation Services Column 2, row 20	31,017.7	27,579.7	3,438
Total Sales and Transportation Services Column 3, row 20	34,450	31,099.4	3,350.6
Total Sales and Transportation Services Column 4, row 20	11,695.6	8,094.6	3,601

	Per Schedule 7	Per Commission Staff	Difference
Total Sales and Transportation Services Column 6, row 20	33,991	30,390	3,601
Total Sales and Transportation Services Column 7, row 20	(458.8)	(709.4)	250.6

	Per Schedule 8	Per Commission Staff	Difference
Residential & Commercial Column 2, row 6	11,522.3	7,921.3	3,601
Residential & Commercial Columns 3 and 5, row 6	11,600.6	7,893.2	3,707.4
Residential & Commercial Column 6, row 6	78.3	(28.1)	106.4
Total Sales Column 2, row 11	11,695.6	8,094.6	3,601
Total Sales Columns 3 and 5, row 11	11,773.9	8,066.5	3,707.4
Total Sales Column 6, row 11	78.3	(28.1)	106.4
Total Sales and Transportation Services Column 2, row 20	33,991	30,390	3,601
Total Sales and Transportation Services Column 3, row 20	11,773.9	8,066.5	3,707.4
Total Sales and Transportation Services Column 5, row 20	34,069.3	30,361.9	3,707.4
Total Sales and Transportation Services Column 6, row 20	78.3	(28.1)	106.4

	Per Schedule 9	Per Commission Staff	Difference
Residential & Commercial Column 2, row 6	11,600.6	7,893.2	3,707.4
Residential & Commercial Columns 3 and 5, row 6	11,687	7,871	3,816
Residential & Commercial Column 6, row 6	86.4	(22.2)	108.6
Total Sales Column 2, row 11	11,773.9	8,066.5	3,707.4
Total Sales Columns 3 and 5, row 11	11,860.3	8,044.3	3,816
Total Sales Column 6, row 11	86.4	(22.2)	108.6
Total Sales and Transportation Services Column 2, row 20	34,069.3	30,361.9	3,707.4
Total Sales and Transportation Services Column 3, row 20	11,860.3	8,044.3	3,816
Total Sales and Transportation Services Column 5, row 20	34,155.7	30,339.7	3,816
Total Sales and Transportation Services Column 6, row 20	86.4	(22.2)	108.6

Response:

This response also addresses BCUC IR 2.139.3, BCUC IR 2.139.4, and BCUC IR 2.139.5.

Several rows in Schedules 7, 8, 9, 10, 11, 12, 13, 14, and 16 of Tab 7.2 were inadvertently hidden in the Application as filed on May 4, 2011. Although these rows were hidden, the values in the rows were included in the subtotals and totals; thus, this was an error in presentation that does not impact the revenue requirement. The hidden rows included the details for rate schedules AGS, SCS 1, SCS 2, and LCS 1. Please refer to the Evidentiary Update submitted on July 19, 2011 which corrected this error in presentation.

139.3 There appears to be a number of adding errors on Schedules 10-12. While the Total Sales on row 11, Total Transportation Service on row 18, and Total Sales and Transportation Services on row 20 agree to the amounts on Schedules 4-6, respectively, as per the cross-reference, the amounts presented on Schedules 10-12 do not add to these totals. The differences are as follows:

($000s)	Per Schedule 10	Per Commission Staff	Difference
Residential & Commercial Column 2, row 5	$167,321	$116,826	$50,495
Residential & Commercial Column 3, row 5	$179,703	$130,491	$49,212
Residential & Commercial Columns 4 and 6, row 5	$170,917	$118,176	$52,741
Residential & Commercial Column 7, row 5	$(8,786)	$(12,315)	$3,529
Total Sales Column 2, row 11	$169,789	$119,294	$50,495
Total Sales Column 3, row 11	$182,402	$133,191	$49,211
Total Sales Columns 4 and 6, row 11	$172,935	$120,194	$52,741
Total Sales Column 7, row 11	$(9,467)	$(12,997)	$3,530
Total Sales and Transportation Services Column 2, row 20	$193,410	$142,915	$50,495
Total Sales and Transportation Services Column 3, row 20	$202,902	$153,690	$49,212
Total Sales and Transportation Services Column 4, row 20	$172,935	$120,194	$52,741
Total Sales and Transportation Services Column 6, row 20	$193,646	$140,905	$52,741
Total Sales and Transportation Services Column 7, row 20	$(9,256)	$(12,785)	$3,529

($000s)	Per Schedule 11	Per Commission Staff	Difference
Residential & Commercial Column 2, row 5	$170,917	$118,176	$52,741
Residential & Commercial Columns 3 and 5, row 5	$172,335	$118,014	$54,321
Residential & Commercial Column 6, row 5	$1,418	$(162)	$1,580
Total Sales Column 2, row 11	$172,935	$120,194	$52,741
Total Sales Columns 3 and 5, row 11	$174,353	$120,032	$54,321
Total Sales Column 6, row 11	$1,418	$(162)	$1,580
Total Sales and Transportation Services Column 2, row 20	$193,646	$140,905	$52,741
Total Sales and Transportation Services Column 3, row 20	$174,353	$120,032	$54,321
Total Sales and Transportation Services Column 5, row 20	$195,087	$140,766	$54,321
Total Sales and Transportation Services Column 6, row 20	$1,441	$(139)	$1,580

($000s)	Per Schedule 12	Per Commission Staff	Difference
Residential & Commercial Columns 2, row 5	$172,335	$118,014	$54,321
Residential & Commercial Columns 3 and 5, row 5	$173,895	$117,950	$55,945
Residential & Commercial Column 7, row 5	$1,560	$(64)	$1,624
Total Sales Column 2, row 11	$174,353	$120,031	$54,322
Total Sales Columns 3 and 5, row 11	$175,913	$119,968	$55,945

($000s)	Per Schedule 12	Per Commission Staff	Difference
Total Sales Column 6, row 11	$1,560	$(64)	$1,624
Total Sales and Transportation Services Column 2, row 20	$195,087	$140,765	$54,322
Total Sales and Transportation Services Column 3, row 20	$175,913	$119,968	$55,945
Total Sales and Transportation Services Column 5, row 20	$196,647	$140,702	$55,945
Total Sales and Transportation Services Column 6, row 20	$1,560	$(64)	$1,624

Response:

Please refer to the response for BCUC IR 2.139.1.

139.4 Schedule 13 - Amounts in each of the columns 2 to 7 do not add to the totals shown on rows 6 (Residential & Commercial), 13 (Total Sales), and 15 (Total Sales and Transportation Services). The totals do, however, agree to the Cost of Gas Sold amounts in Schedules 4-6 respectively, as per the cross reference.

Response:

Please refer to the response for BCUC IR 2.139.1.

139.5 Schedule 14 and 16– Amounts in each of the columns 2, 4, 6, 9, and 11 do not add to the totals shown on rows 6 (Residential & Commercial), 11 (Total Sales), and 15 (Total Non-Bypass Sales & Transportation Services). The totals do, however agree to the Total Sales on Schedules 8 and 11, as per the cross reference.

Response:

Please refer to the response for BCUC IR 2.139.1.

139.6 Schedule 15 and 17– The sum of row 15 from Schedule 14 and 16 respectively and row 7 of Schedule 15 and 17 respectively do not equal the Total Non-Bypass and Bypass Sales and Transportation Service shown in columns 2, 4, 6, 9, and 11.

Response:

The following table demonstrates that the summation of the subtotals (i.e. Line 15 of Schedule 14 and 16 and Line 7 of Schedule 15 and 17) do in fact equal the totals as reported on Line 10 of Schedules 15 and 17 of Tab 7.2. Please also refer to the response to BCUC IR 2.139.1.

2012 - Schedules 14 & 15		Terajoules	Revenue	Margin	Customers	Revenue
	Column Ref:	(2)	(4)	(6)	(9)	(11)
Schedule / Line No.						
Sch 14 / Line 15	Non-Bypass	11,773.9	$174,353	$100,018	103,750	$174,357
Sch 15 / Line 7	Bypass	22,295.4	20,734	20,734	4	$ 20,734
Sche 15 / Line 10	Non-Bypass & Bypass	34,069.3	$195,087	$120,752	103,754	$195,091
Difference: Line 15 + Line 7 - Line 10		-	-	-	-	-

2013 - Schedules 16 & 17		Terajoules	Revenue	Margin	Customers	Revenue
	Column Ref:	(2)	(4)	(6)	(9)	(11)
Schedule / Line No.						
Sch 16 / Line 15	Non-Bypass	11,860.3	$175,913	$ 99,513	106,356	$193,353
Sch 17 / Line 7	Bypass	22,295.4	20,734	20,734	4	20,734
Sche 17 / Line 10	Non-Bypass & Bypass	34,155.7	$196,647	$120,247	106,360	$214,087
Difference: Line 15 + Line 7 - Line 10		-	-	-	-	-

139.7 Schedule 33 – Amounts in columns 2, 3, and 5 do not add to the totals shown in row 25.

Response:

In Schedule 33, the Removal Cost deductions (Line 21) for 2010 Actual (column 2) and 2011 Approved (column 3) were incorrectly displayed as zero. Rather than zero, Line 21 should have displayed deductions of $343 and $344 thousand, for 2010 and 2011 respectively. Although not displayed on the schedule, these deductions were correctly included in the total on Line 25; therefore, this error does not impact the calculation of the revenue requirement.

An amended Schedule 33 is provided below.

FORTISBC ENERGY (Vancouver Island) INC.

BCUC IR2 - 139.7

Section 7
TAB 7.2
Schedule 33

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars (1)	2010 ACTUAL (2)	2011 APPROVED (3)	2011 PROJECTED (4)	Change (5) (Column (4) - Column (3))	Cross Reference (6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 60	$ 68	$ 60	$ (8)	
3	Depreciation	21,897	26,330	25,380	(950)	- Sect 7-TAB 7.2, Schedule 27
4	Amortization of Debt Issue Expenses	328	42	418	376	
5	Pension Expense	1,408	1,484	1,023	(461)	
6	OPEB Expense	937	954	840	(114)	
7	Unpaid Remuneration	273	-	-	-	
8	IFRS Revenue Requirement Adjustment	1,400	-	(1,400)	(1,400)	
9	Variance in O&M expenses - Actual vs. Allowed	1,379	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	(6,209)	727	4,350	3,623	- Sect 7-TAB 7.2, Schedule 27
13	Amortization of Revenue Surplus / RSDA (FEVI)	(1,481)	(1,481)	(1,481)	-	- Sect 7-TAB 7.2, Schedule 27
14	Capital Cost Allowance	(29,166)	(38,743)	(36,646)	2,097	- Sect 7-TAB 7.2, Schedule 36
15	Cumulative Eligible Capital Allowance	(354)	(352)	(361)	(9)	
16	Debt Issue Costs	(823)	(862)	(666)	196	
17	Pension Contributions	(1,417)	(1,443)	(2,687)	(1,244)	
18	OPEB Contributions	(221)	(218)	(269)	(51)	
19	Overheads Capitalized Expensed for Tax Purposes	(2,811)	(2,936)	(2,943)	(7)	
20	Overhead Capitalization Rate Change	-	-	-	-	
21	Removal Costs	(343)	(344)	(344)	0	
22	Major Inspection Costs	(544)	(460)	(550)	(90)	
23	Taxable Capital Gain	21	60	-	(60)	
24						
25	TOTAL	$ (15,666)	$ (17,174)	$ (15,276)	$ 1,898	- Sect 7-TAB 7.2, Schedule 30

139.8 Schedule 36 – How do you compute the 2011 CCA for row 2 (Class 1b), row 16 (Class 47) and row 17 (Class 49)?

Response:

Pursuant to capital cost allowance rules commonly referred to as the "long-term project election" and "rolling start" rules which commence in year three of a long-term construction project, the following expenditures were added to Classes 1(b), 47, and 49 with respect to the Mt. Hayes LNG project that are not subject to the ½ year rule.

Class 1(b)	$4,426,000
Class 47	$58,214,000
Class 49	$5,373,000

The remainder of the additions to these CCA classes include additions to the Mt. Hayes LNG project and other assets that are subject to the ½ year rule.

	Mt. Hayes	Other
Class 1(b)	$2,108,000	$181,000
Class 47	$38,664,000	
Class 49	$3,657,000	$5,294,000

Therefore, the computation of the CCA for Class 1(b), 47 and 49 on Schedule 36 is as follows (amounts shown are in thousands):

			Additions subject to 1/2 year rule		Columns (4 + 5)	Additions not subject to 1/2 year rule	Columns (6 + 7)	Columns (4 + 5) x 2 x 50%	Columns (3 + 7) x 2	Columns (9 + 10)
Class	CCA rate	Opening	Mt. Hayes	Other	Subtotal - 1/2 Yr rule	Mt. Hayes	Total Additions	CCA (1/2 Yr rule)	CCA (no 1/2 Yr rule)	Total CCA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1(b)	6%	5,794	2,108	181	2,289	4,426	6,715	69	613	**682**
47	8%	65,251	38,664	-	38,664	58,214	96,878	1,547	9,877	**11,424**
49	8%	28,525	3,657	5,294	8,951	5,373	14,324	358	2,712	**3,070**

139.9 Schedule 46 – How is the Mid-Year GPIS for Depreciation in column 10, row 13 computed for 402-01 Application Software – 12.5%? It appears that neither the Mid-Year basis nor the 13 Month Adjustment is used.

Response:

This response also applies to BCUC IR 2.139.10.

The Mid-Year GPIS for Depreciation amounts, as shown in Column 10 of Schedules 43-51, represents the mid-year balance of gas plant in service, and also an adjustment for the timing of the in-service date of CPCN projects. Therefore, in some cases, the balance used to determine depreciation may not be the opening balance plus closing balance, divided by two as described in the question.

FEVI acknowledges that the mid-year balance as displayed in column 10 on Schedules 46-48 is incorrect. An error in the presentation of the balances in Column 10 of the schedules occurred because of an incorrect adjustment for CCE CPCN related expenditures. Therefore, the correct calculation for the Total Mid-Year GPIS for Depreciation on Schedule 49 Column 10 Row 32 is ($1,263,166 + $1,317,658)/2 + $1,210 = $1,291,621 as shown in the schedules below. The $1,210 is the 13 month adjustment found on Schedule 40 Column 3 Row 23.

This error was limited only to the presentation of the balance on this schedule; that is, the calculation basis for depreciation expense is not impacted by this error. Revised Schedules 46-48, providing the correct Mid-Year GPIS for Depreciation balances in Column 10, are included below:

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	190	-	-	-	-	-	-	190	190
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	-	-	-	-	-	-	1,219	1,219
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	-	-	-	-	-	-	6,847	6,847
11	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
12	471-00 Distribution Land Rights	1,866	-	-	-	-	-	-	1,866	1,866
13	402-01 Application Software - 12.5%	16,272	5,932	600	9	-	(931)	-	21,882	22,043
14	402-02 Application Software - 20%	3,064	-	600	14	-	(96)	-	3,582	3,323
15	TOTAL INTANGIBLE	29,482	5,932	1,200	23	-	(1,027)	-	35,610	35,512
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipmei	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	1,006	-	-	-	-	-	-	1,006	1,006
27	442-00 Structures & Improvements (Mount Hayes)	17,047	-	-	-	-	-	-	17,047	17,047
28	443-00 Gas Holders - Storage (Mount Hayes)	60,902	-	750	-	-	-	-	61,652	61,277
29	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
30	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
31	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
32	448-10 Piping (Mount Hayes)	11,632	-	-	-	-	-	-	11,632	11,632
33	448-20 Pre-treatment (Mount Hayes)	29,081	-	-	-	-	-	-	29,081	29,081
34	448-30 Liquefaction Equipment (Mount Hayes)	29,081	-	-	-	-	-	-	29,081	29,081
35	448-40 Send out Equipment (Mount Hayes)	23,265	-	-	-	-	-	-	23,265	23,265
36	448-50 Sub-station and Electric (Mount Hayes)	21,851	-	-	-	-	-	-	21,851	21,851
37	448-60 Control Room (Mount Hayes)	6,011	-	-	-	-	-	-	6,011	6,011
38	449-00 Local Storage Equipment (Mount Hayes)	38	-	-	-	-	-	-	38	38
39	TOTAL MANUFACTURED	199,914	-	750	-	-	-	-	200,664	200,289

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 2,842	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,842	$ 2,842
3	461-00 Transmission Land Rights	78	-	80	-	-	-	-	158	118
4	461-02 Land Rights - Mt. Hayes	536	-	-	-	-	-	-	536	536
5	462-00 Compressor Structures	11,705	-	-	-	-	-	-	11,705	11,705
6	463-00 Measuring Structures	7,517	-	-	-	-	-	-	7,517	7,517
7	464-00 Other Structures & Improvements	130	-	-	-	-	-	-	130	130
8	465-00 Mains	327,983	-	3,111	71	718	-	-	331,883	329,933
9	465-00 Mains - INSPECTION	3,438	-	275	-	63	-	-	3,776	3,607
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,492	-	-	-	-	-	-	6,492	6,492
12	466-00 Compressor Equipment	59,891	-	2,457	32	567	-	-	62,947	61,419
13	466-00 Compressor Equipment - OVERHAUL	5,861	-	1,450	-	335	-	-	7,646	6,754
14	467-00 Mt. Hayes - Measuring and Regulating Equipment	6,021	-	-	-	-	-	-	6,021	6,021
15	467-10 Measuring & Regulating Equipment	14,064	-	-	-	-	-	-	14,064	14,064
16	467-20 Telemetering	41	-	-	-	-	-	-	41	41
17	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
18	468-00 Communication Structures & Equipment	3,780	-	-	-	-	-	-	3,780	3,780
19	TOTAL TRANSMISSION	492,619	-	7,373	103	1,683	-	-	501,778	497,199
20										
21	**DISTRIBUTION PLANT**									
22	470-00 Land in Fee Simple	799	-	-	-	-	-	-	799	799
23	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
24	472-00 Structures & Improvements	2,302	-	-	-	-	-	-	2,302	2,302
25	473-00 Services	179,738	-	5,748	-	1,326	(161)	-	186,651	183,195
26	474-00 House Regulators & Meter Installations	23,797	-	-	-	-	-	-	23,797	23,797
27	477-00 Meters/Regulators Installations	-	-	847	-	-	-	-	847	424
28	475-00 Mains	286,084	-	8,448	-	1,949	(110)	-	296,371	291,228
29	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
30	477-00 Measuring & Regulating Equipment	8,643	-	325	-	75	(29)	-	9,014	8,829
31	477-00 Telemetering	124	-	100	-	23	-	-	247	186
32	478-10 Meters	14,046	-	847	-	-	(443)	-	14,450	14,248
33	478-20 Instruments	-	-	-	-	-	-	-	-	-
34	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
35	TOTAL DISTRIBUTION	515,533	-	16,315	-	3,373	(743)	-	534,478	525,006
36										

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 48

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1,268	6,355	-	-	-	-	-	7,623	3,223
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	3,959	-	-	-	-	-	-	3,959	3,959
6	- Masonry Buildings	1,172	8,482	365	-	-	-	-	10,019	4,557
7	- Leasehold Improvement	506	361	45	-	-	(313)	-	599	733
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	653	110	6	-	-	-	-	769	717
10	483-40 GP Furniture	429	361	20	-	-	-	-	810	751
11	483-10 GP Computer Hardware	2,620	372	800	13	-	-	-	3,805	3,399
12	483-20 GP Computer Software	261	-	-	-	-	-	-	261	261
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
15	484-00 Vehicles	5,946	-	2,913	-	-	(202)	-	8,657	7,302
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	323	-	-	-	-	(11)	-	312	318
18	485-20 Heavy Mobile Equipment	1,267	-	160	-	-	-	-	1,427	1,347
19	486-00 Small Tools & Equipment	6,582	-	3	-	-	(320)	-	6,265	6,424
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	581	-	-	-	-	(10)	-	571	576
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	25,618	16,041	4,312	13	-	(856)	-	45,128	33,616
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 1,263,166	$ 21,973	$ 29,950	$ 139	$ 5,056	$ (2,626)	$ -	$ 1,317,658	$ 1,291,621

139.10 Schedule 48 – How is the Mid-Year GPIS for Depreciation in column 10, rows 7, 10, and 11 computed for 482-00 Structures & Improvement – Leasehold Improvement, 483-40 GP Furniture and 483-10 GP Computer Hardware, respectively? It appears that neither the Mid-Year basis nor the 13 Month Adjustment is used.

Response:

Please see response to BCUC IR 2.139.9.

139.11 Schedules 61 and 62– Column 2 does not add to the totals shown on row 9, 'Total Transmission', row 19, 'Total Distribution', and row 21, 'Totals'. Please revise these schedules if there is an error or explain the difference if there is no error.

Response:

Revised versions of Schedules 61 and 62 are provided below, with the totals in column 2 corrected. The incorrect totals did not carry forward to any other financial schedules, and therefore did not affect any of the revenue requirement or rate calculations.

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 61

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	11,705	0.18%	21	219	-	-	-	240
3	463-00 Measuring Structures	7,517	0.00%	-	95	-	-	-	95
4	464-00 Other Structures & Improvements	130	0.14%	-	-	-	-	-	-
5	465-00 Mains	329,933	0.17%	571	2,672	-	-	-	3,243
6	466-00 Compressor Equipment	61,419	0.30%	184	404	-	-	-	588
7	467-10 Measuring & Regulating Equipment	14,064	0.21%	30	72	-	-	-	102
8	468-00 Communication Structures & Equipment	3,780	2.21%	84	-	-	-	-	84
9	TOTAL TRANSMISSION	428,548		890	3,462	-	-	-	4,352
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	2,302	0.17%	4	22	-	-	-	26
13	473-00 Services	183,195	1.02%	1,869	3,009	(250)	-	-	4,628
14	474-00 House Regulators & Meter Installations	23,797	0.77%	183	(97)	-	-	-	86
15	474-00 House Regulators & Meter Installations - LILO	-	0.00%	-	-	-	-	-	-
16	477-00 Meters/Regulators Installations	424	0.77%	3	-	-	-	-	3
17	475-00 Mains	291,228	0.31%	903	2,845	(207)	-	-	3,541
18	477-00 Measuring & Regulating Equipment	8,829	0.00%	-	75	(175)	-	-	(100)
19	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
20	478-10 Meters	14,248	0.45%	64	(123)	-	-	-	(59)
21	TOTAL DISTRIBUTION	524,021		3,026	5,731	(632)	-	-	8,125
22									
23	TOTALS	$ 952,569		$ 3,916	$ 9,193	$ (632)	$ -	$ -	$ 12,477
24									
25	Cross Reference			- Sect 7-TAB 7.2, Schedule 28				- Sect 7-TAB 7.2, Schedule 40	

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 62

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	11,705	0.18%	21	-	-	-	240	261
3	463-00 Measuring Structures	7,517	0.00%	-	-	-	-	95	95
4	464-00 Other Structures & Improvements	130	0.14%	-	-	-	-	-	-
5	465-00 Mains	334,229	0.17%	578	-	-	-	3,243	3,821
6	466-00 Compressor Equipment	64,195	0.30%	193	-	-	-	588	781
7	467-10 Measuring & Regulating Equipment	14,064	0.21%	30	-	-	-	102	132
8	468-00 Communication Structures & Equipment	3,780	2.21%	84	-	-	-	84	168
9	TOTAL TRANSMISSION	435,619		906	-	-	-	4,352	5,258
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	2,302	0.17%	4	-	-	-	26	30
13	473-00 Services	190,593	1.02%	1,944	-	(250)	-	4,628	6,322
14	474-00 House Regulators & Meter Installations	23,575	0.77%	182	-	-	-	86	268
15	474-00 House Regulators & Meter Installations - LILO	-	0.00%	-	-	-	-	-	-
16	477-00 Meters/Regulators Installations	1,288	0.77%	10	-	-	-	3	13
17	475-00 Mains	301,214	0.31%	934	-	(223)	-	3,541	4,252
18	477-00 Measuring & Regulating Equipment	9,231	0.00%	-	-	(175)	-	(100)	(275)
19	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
20	478-10 Meters	14,669	0.45%	66	-	-	-	(59)	7
21	TOTAL DISTRIBUTION	542,871		3,140	-	(648)	-	8,125	10,617
22									
23	TOTALS	$ 978,490		$ 4,046	$ -	$ (648)	$ -	$ 12,477	$ 15,875
24									
25	Cross Reference			- Sect 7-TAB 7.2, Schedule 29				- Sect 7-TAB 7.2, Schedule 41	

139.12 Schedule 72, 73 and 74 – The amounts in columns 2-5 do not add to the subtotals shown on rows 18 and 20 in each of these schedules. Please revise or explain the difference.

Response:

Please refer to the Evidentiary Update filed July 19, 2011.

The subtotals (line 18) and totals (line 20) were correct as shown on Schedules 72-74; the source for the discrepancy was a hidden row which was included in the calculations but not visible on the schedules. FEVI discovered this issue in presentation and amended Section 7.2, Schedules 72-74 in the Evidentiary Update to display the line for Refundable Contributions which had been inadvertently hidden from view. This revision did not impact the calculations or other financial schedules as the amounts for the refundable contributions were embedded in the totals.

The amended Schedules as provided in the Evidentiary Update are included below:

FORTISBC ENERGY (Vancouver Island) INC. — Evidentiary Update - July 19, 2011 — Section 7, TAB 7.2, Schedule 72

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Cash Working Capital						
2	Cash Required for						
3	Operating Expenses	$ 2,163	$ 1,909	$ 2,087	$ 1,740	$ (169)	- Sect 7-TAB 7.2, Schedule 75
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(890)	(890)	(968)	(968)	(78)	
9							
10	Withholdings From Employees	(243)	(730)	(251)	(251)	479	
11							
12	Subtotal	1,029	134	868	521	387	- Sect 7-TAB 7.2, Schedule 39
13							
14	Other Working Capital Items						
15	Transmission Line Pack Gas	822	1,321	610	610	(711)	
16	Gas in Storage	9,895	11,146	9,280	9,280	(1,866)	
17	Refundable Contributions	(289)	(290)	(291)	(291)	(1)	
18							
19	Subtotal	10,428	12,178	9,599	9,599	(2,579)	- Sect 7-TAB 7.2, Schedule 39
20							
21	Total	$ 11,458	$ 12,312	$ 10,467	$ 10,120	$ (2,192)	

FORTISBC ENERGY (Vancouver Island) INC. — Evidentiary Update - July 19, 2011 — Section 7, TAB 7.2, Schedule 73

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 1,740	$ 1,760	$ 1,759	$ 19	- Sect 7-TAB 7.2, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(968)	(1,132)	(1,132)	(164)	
9						
10	Withholdings From Employees	(251)	(261)	(261)	(10)	
11						
12	Subtotal	521	367	366	(155)	- Sect 7-TAB 7.2, Schedule 40
13						
14	**Other Working Capital Items**					
15	Transmission Line Pack Gas	610	728	728	118	
16	Gas in Storage	9,280	10,605	10,605	1,325	
17	Refundable Contributions	(291)	(291)	(291)	-	
18						
19	Subtotal	9,599	11,042	11,042	1,443	- Sect 7-TAB 7.2, Schedule 40
20						
21	Total	$ 10,120	$ 11,409	$ 11,408	$ 1,288	

FORTISBC ENERGY (Vancouver Island) INC. — Evidentiary Update - July 19, 2011 — Section 7, TAB 7.2, Schedule 74

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 1,759	$ 1,758	$ 2,028	$ 269	- Sect 7-TAB 7.2, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(1,132)	(1,206)	(1,206)	(74)	
9						
10	Withholdings From Employees	(261)	(269)	(269)	(8)	
11						
12	Subtotal	366	283	553	187	- Sect 7-TAB 7.2, Schedule 41
13						
14	**Other Working Capital Items**					
15	Transmission Line Pack Gas	728	792	792	64	
16	Gas in Storage	10,605	9,935	9,935	(670)	
17	Refundable Contributions	(291)	(291)	(291)	-	
18						
19	Subtotal	11,042	10,436	10,436	(606)	- Sect 7-TAB 7.2, Schedule 41
20						
21	Total	$ 11,408	$ 10,719	$ 10,989	$ (419)	

140.0 Reference: Financial Schedules

Exhibit B-1, Tab 7.3- Whistler

Discrepancies in Various Schedules

For the following discrepancies, please revise the schedules if the amounts are indeed incorrect or provide an explanation for the difference.

140.1 Schedule 36 – It would appear that the sub-totals for the CEC Opening Balance on row 37 and the CEC closing Balance on row 49 are incorrect. For the CEC Opening Balance the additions are subtracted from the opening balance instead of added to it, and for the CEC Closing Balance, the annual allowance is added to the Cumulative Eligible Capital Balance on row 45 instead of being subtracted. Notwithstanding, it doesn't appear that the annual allowance is calculated using the Cumulative Eligible Capital Balance on row 45 for 2012 and 2013. Please explain how the annual allowance on row 47 is determined for the 2012 and 2013 forecast.

<u>Response:</u>

Please refer to the Evidentiary Update filed on July 19, 2011. As identified in the question, the annual allowance being added to the CEC balance on row 45 instead of subtracted was an error in presentation that did not impact the calculation of the CCA. FEW identified this presentation error and revised Schedule 36 of Section 7.3 in the July 19, 2011 Evidentiary Update. In this revised schedule, the negative addition in 2012 of $1,863 is related to the opening balance adjustment for the reduction in the Whistler Pipeline Capital Contribution to FEVI ($2,484 * 75% = $1,863) and as such, is correct in being deducted from the opening balance.

The updated CEC continuity as included in the Evidentiary Update is shown below.

* CUMULATIVE ELIGIBLE CAPITAL *

Particulars	2010 ACTUAL	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
(1)	(2)	(3)	(4)	(5)	(6)
CEC Opening Balance	$ 17,559	$ 16,311	$ 15,169	$ 12,375	
75% of Eligible Capital Expenditures incurred	(20)	-	(1,863)	-	
Subtotal:	17,539.0	16,311.0	13,306.0	12,375.0	
Sale of Eligible Capital Property					
Sale of Eligible Capital Property before June 18, 1987					
Subtotal:	-	-	-	-	
75 % Adjustment	-	-	-	-	
Cumulative Eligible Capital Balance	17,539	16,311	13,306	12,375	
Annual Allowance (7%)	(1,228)	(1,142)	(931)	(866)	- Sect 7-TAB 7.3, Schedule 33
CEC Closing Balance	$ 16,311	$ 15,169	$ 12,375	$ 11,509	

140.2 Schedules 61 and 62 – These schedules appear to be missing the details relating to General Plant & Equipment as row 12 does not equal row 15 in column 2.

Response:

Revised versions of Schedules 61 and 62 are provided below, with the totals in column 2 corrected. The incorrect totals did not carry forward to any other financial schedules, and therefore did not affect any of the revenue requirement or rate calculations.

FORTISBC ENERGY (Whistler) INC. Section 7

TAB 7.3

NEGATIVE SALVAGE CONTINUITY Schedule 61

FOR THE YEAR ENDING DECEMBER 31, 2012

($000s)

Line No.	Account	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	472-00 Structures & Improvements	2	0.17%	-	-	-	-	-	-
3	473-00 Services	4,106	1.00%	41	-	(5)	-	-	36
4	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
5	474-00 House Regulators & Meter Installations	1,432	0.65%	9	-	-	-	-	9
6	475-00 Mains	9,194	0.30%	28	-	(1)	-	-	27
7	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
8	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	640	0.00%	-	-	-	-	-	-
10	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
11	478-10 Meters	479	0.41%	2	-	-	-	-	2
12	TOTAL DISTRIBUTION	15,852		80	-	(6)	-	-	74
13									
14									
15	TOTALS	$ 15,852		$ 80	$ -	$ (6)	$ -	$ -	$ 74
16									
17	Cross Reference			- Sect 7-TAB 7.3, Schedule 28				- Sect 7-TAB 7.3, Schedule 40	
18									

FORTISBC ENERGY (Whistler) INC.

Section 7
TAB 7.3
Schedule 62

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Neg Salvage	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	472-00 Structures & Improvements	2	0.17%	-	-	-	-	-	-
3	473-00 Services	4,249	1.00%	42	-	(5)	-	36	73
4	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
5	474-00 House Regulators & Meter Installations	1,370	0.65%	9	-	-	-	9	18
6	475-00 Mains	9,520	0.30%	29	-	(1)	-	27	55
7	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
8	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	640	0.00%	-	-	-	-	-	-
10	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
11	478-10 Meters	490	0.41%	2	-	-	-	2	4
12	TOTAL DISTRIBUTION	16,270		82	-	(6)	-	74	150
13									
14									
15	TOTALS	$ 16,270		$ 82	$ -	$ (6)	$ -	$ 74	$ 150
16									
17	Cross Reference			- Sect 7-TAB 7.3, Schedule 29				- Sect 7-TAB 7.3, Schedule 41	
18									

140.3 Schedule 85 – In Note 1:

Note 1: RSAM Rider Change

In 2011, FortisBC (Whistler) Energy forecasts that there will be approximately $227 thousand (net-of-tax) of RSAM additions. After offsetting the 2011 RSAM Rider recovery, the RSAM account including interest is now projected to be a debit balance of $378 thousand on a net-of-tax basis by the end of 2011. The RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to be amortized in each year in 2012 and 2013 is a debit of $281 thousand and $280 thousand, respectively. On a pre-tax basis, this amounts to $375 thousand, equivalent to a charge to the customer of $0.524/GJ in 2012. The corresponding 2013 charge to the customer is $0.529/GJ."

2012 Net-Of-Tax Amortization = 1/3 of the sum of Projected December 31, 2011 RSAM Balance plus 2012 Opening Balance Adjustment
= 1/3 * ($843 RSAM + $-1 RSAM Interest)
= 1/3 * $842
= $281 Net-of-tax amortization

In the first sentence the amount of the remaining RSAM balance net of tax at the end of 2011 is $378 thousand, however, the amount on which the 2012 Net of Tax Amortization is determined is $843 thousand RSAM plus $-1 thousand RSAM Interest). The RSAM appears to be defined as the sum of the Projected December 31, 2011 RSAM balance plus the 2012 Opening Balance Adjustment. Please confirm that the 2012 Opening Balance Adjustment is $465 thousand or provide an explanation for the difference between $378 thousand in the preamble and the $843 thousand used in the calculation of the 2012 Net of Tax Amortization.

Response:

The 2012 opening balance adjustment is $464 thousand and is related to the transfer of the Sales Margin Differential deferral to the RSAM deferral at the beginning of 2012 as described in Section 6.3.1.3 of Exhibit B-1. The net of tax balance for amortization is comprised of the following:

	$ Thousands
December 31, 2011 RSAM Balance (before interest)	379
Opening Adjustment (Sales Margin Differential)	464
RSAM Interest	(1)
	842