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June 30, 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 ("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. 1

On May 4, 2011, the FEU filed the Application as referenced above. In accordance with Commission Order No. G-81-11 setting out the Regulatory Timetable for the review of the Application, and further amended by Commission Letter No. L-45-11, the FEU respectfully submit the attached response to BCUC IR No. 1.

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

1.0 Reference: Introduction

Exhibit B-1, Application, Part 1.2, p. 10

Recent Rate Setting Processes and Regulatory Proceedings

According to the Application, recent rate setting processes and regulatory proceedings (specifically mentioned were the determination processes for Mainland and FEVI 2010 and 2011 rates, the FEW 2010 and 2011 rates, the Fort Nelson division 2011 rates) laid the foundation for the Utilities to deliver on several initiatives (emphasis added). Those initiatives include, among others, Enhanced Energy Efficiency and Conservation programs; and enhanced service offerings for customers such as biomethane service offering, a business model and rate design for compressed natural gas (CNG) and liquefied natural gas (LNG) fueling service, and approval to pursue Alternative Energy Services (AES) within FEU.

1.1 Do FEU agree that the requests for expenditures in revenue requirements applications must align with the program's initial approval Order, especially when programs are in their early stages of existence?

Response:

The Companies agree in general that when executing a project or program, the Companies should follow the Commission Order approving the project. The FortisBC Energy Utilities have in their approved projects and programs made every effort to adhere to the Commission orders and directives.

1.2 Does FEU agree that all new alternative energy services must be approved on a project by project basis until the Commission directs FEU otherwise?

Response:

The Companies interpret the term "alternative energy services" in both the preamble and the question to include geo-exchange, solar-thermal and district energy systems as those services were used in the FEI's 2010-2011 Revenue Requirement Application and approved by the Commission Order No. G-141-09. As indicated in section 1.2.3.3 of the Application (Exhibit B-1), the Companies now use the term "Thermal Energy Services" to refer to the same services.

The Companies agree that new Alternative Energy Service (or Thermal Energy Service) projects should be approved on a project-specific basis, by following the process that was contemplated in the NSA approved by Commission Order No. G-141-09. In particular, the NSA states:

> *"... Pursuant to the Utilities Commission Act, within the Alternative Energy class of service, project-specific contracts with AES customers will be filed with the Commission for acceptance as a rate, at which time the Commission may review and adjust the economic test and GT&C Section 12A – Alternative Energy Extensions. The CPCN threshold of $5 million applies to AES projects brought forward in 2010 and 2011."* [Emphasis added.]

As explained on page 15 of the Application (Exhibit B-1-2), FEI is expecting to bring forth individual projects with signed contracts for Commission approval later this year.

As AES Projects develop further, FEI may consider applying to the Commission for approval of AES projects on a different basis.

1.3 Do FEU agree that tariff provisions from a Commission order approving a negotiated settlement process do not necessarily imply a regulatory policy?

Response:

It is unclear to the Companies what is meant by a "regulatory policy." Regardless, the status of a tariff provision approved by the Commission is the same, whether it is the product of a Negotiated Settlement Process or not.

A Commission order approving a Negotiated Settlement Agreement (NSA) is based on a full consideration of the evidence and is just as valid and enforceable as an order issued following a written or oral hearing process. The Commission's approval of a rate is made under sections 59 to 61 of the UCA, whether the tariff provision or rate is approved through a written or oral hearing process or following a Negotiated Settlement Process. Under section 60 of the UCA, the approval of a tariff provision is based on the Commission's consideration of "all matters that it considers proper and relevant affecting the rate," which may include consideration of regulatory policies. Under section 61(3) of the UCA, a tariff provision filed with and approved by the Commission becomes part of the enforceable and collectable rates of a utility and "no other rate may be collected, charged or enforced" by the utility. Pursuant to section 61(2), the tariff provision remains in place until the Commission orders otherwise; it "must not be rescinded or amended without the commission's consent."

If a tariff provision approved as part of a NSA were not considered an approved Commission rate, it would undermine the purpose of a Negotiated Settlement Process and result in serious business concerns for the utilities and customers that have made commercial decisions, including investing significant capital, in reliance on the approved tariff provisions.

2.0 Reference: Enhanced Energy Efficiency and Conservation (EEC) Programs

Exhibit B-1, Part 1.1, p. 5 and Part 1.2.2, pp. 11-12

EEC Funding – Rate Impact

"Changes to the FEI revenue requirements result in revenue deficiencies of $29.0 million in 2012 and $36.8 million in 2013." (Exhibit B-1, p.5)

"In this Application the FEU are proposing an increase in the allowed funding envelope for 2012 and 2013 to $74.5 million in total for each year." (Exhibit B-1, pp. 11-12)

2.1 How much of the FEI revenue deficiencies of $29.0 million in 2012 and 36.8 million in 2013 are due to the increase in EEC funding to $74.5 million in total for each year?

Response:

It is the FEU's forecast EEC rate base additions of $20.0 million per year that impact the revenue requirements and the revenue deficiencies for 2012 and 2013. The remaining $54.5 million, of the total EEC funding envelope of $74.5 million, does not impact the revenue deficiency in 2012 and 2013 since the amount (on an as-spent basis) will be captured in a non-rate base deferral account. As discussed in Section 6.3.2.1 of the Application (Exhibit B-1), the FEU have proposed a modification to the deferral account mechanism resulting in additions to the rate base accounts of $20.0 million each year, allocated amongst the utilities. Any remaining expenditures, to a maximum of $54.5 million, will be captured on an as-spent basis in a non-rate base deferral account with recovery beginning in 2014.

Changes to the balance in the FEI EEC rate base deferral account offset the revenue deficiency in 2012 with a revenue surplus impact (i.e. rate decreasing impact) of $0.7 million and contributes approximately $2.7 million to the revenue deficiency in 2013 (cumulative revenue deficiency of $2.0 million in 2013), when compared to existing approved 2011 delivery rates.

Please refer to BCUC IR 1.104.2 for a discussion on the proposed changes to the EEC deferral account.

3.0 Reference: Executive Summary and Introduction

Exhibit B-1, Part 1.2.2, p. 11

Under spending in Energy Efficiency and Conservation Programs

"This brought the total funding for EEC activities to $31.0 million in 2010 and $35.3 million in 2011. Of this approved expenditure, FEU spent $12.6 million in 2010 and is projecting to spend $25.7 million in 2011."

FEU underspent by $18.4 million in 2010 and is projected to under spend by $9.6 million in 2011. "FEI earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change."

3.1 The total approved amount of the EEC programs is included in the rate base on which the revenue requirement is calculated, such that spending less than the total approved amount results in a "benefit" to the shareholders in 2010 and 2011. Please provide the amount of such "benefit" in each of 2010 and 2011. Please confirm the shareholder benefits when there is under spending of the approved amounts in the EEC programs to the extent amounts are included in the forecasts of the RRA.

Response:

The FEU interpret the term shareholder "benefit" in the question preamble to refer to the shareholder's equity return on rate base associated with the variance in the EEC deferral account from the approved balance embedded in rates. As explained below, the variance in the EEC deferral account from the approved balance embedded in rates does not necessarily result in the shareholder earning more than its approved return on equity.

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. For example, when all cost of service items (including the variance in EEC spending) and revenues are considered, the actual return on equity for FEI in 2010 was 9.42% as compared to the approved return on equity of 9.50%.[1] In the case of FEVI, pursuant to BCUC Order No. G-140-09, any variance in the cost of service as compared to approved for 2010 and 2011 (excluding variances in O&M) is captured in the RSDA and later returned to, or recovered from customers.

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[1] The actual return on equity is provided here (please see BCUC IR 1.132.1). Appendix D-5 provides the normalized actual return on equity calculated as 9.36%.

The following table shows that in Mainland an equity return of approximately $305 thousand in 2010 was earned on EEC spending that did not occur, and approximately $667 thousand in 2011 is forecast to be earned on the variance in EEC spending. As noted above, any variance in EEC spending in Vancouver Island is captured in the RSDA. Therefore, the FEVI impacts as shown in the table below, of approximately $64 thousand in 2010 and approximately $194 thousand in 2011, will contribute to the surplus balance in the RSDA in each respective year.

Equity Return of Variance in Mid-Year Balance of EEC Deferral Account

	2010					2011				
$ Thousands	**Approved Mid-Year Balance**	**Actual Mid-Year Balance**	**Variance**	**Equity Return %**	**Equity Return $**	**Approved Mid-Year Balance**	**Projected Mid-Year Balance**	**Variance**	**Equity Return %**	**Equity Return $**
Mainland	15,104	7,081	8,023	3.80% [1]	305	33,460	15,897	17,563	3.80% [1]	667
Vancouver Island	2,777	596	1,599	4.00% [2]	64	6,443	1,599	4,843	4.00% [2]	194
Total Equity Return	17,881	7,677	9,622		369	39,903	17,496	22,406		861

[1] 9.5% Return on Capital x 40% Equity Component

[2] 10% Return on Capital x 40% Equity Component

As discussed in Section 6.3.2.1 of this Application (Exhibit B-1) and in response to BCUC IR 1.104.2, the FEU have proposed a modification to the EEC deferral account mechanism whereby only a portion of the forecast EEC spending is included as a rate base addition in each year, with any additional expenditures being recorded in a non-rate base deferral account as incurred.

For 2012 and 2013 the FEU is proposing an increase in the allowed funding envelope to $74.5 million in total for each year.

3.2 Per Table K-2 in Appendix K-1, it would appear that the 2012 and 2013 proposed funding include amounts that were previously approved (i.e. for 2010 and 2011). Please confirm if the proposed funding for 2012 and 2013 include unspent amounts relating to expenditures that were budgeted for in 2010 and 2011 but were not incurred?

Response:

The proposed EEC funding for 2012 and 2013 does not include amounts relating to expenditures that were budgeted for in 2010 and 2011 but were not incurred. In Table K-2, the line titled "Subtotal-Previously Approved EEC Activity" was not meant to imply that unspent EEC amounts from 2010 and 2011 had been transferred to 2012 and 2013. Rather, the intent was to illustrate that the types of activities that are above this line are the same types of activities that were included in the approved EEC funding amounts for 2010 and 2011.

3.2.1 If yes, please explain the reasons for its inclusion in the 2012 and 2013 rate bases when it was already included and approved in 2010 and 2011.

Response:

Please refer to BCUC IR 1.3.2.

3.2.2 If no, will the unspent approved amounts for 2010 and 2011 be spent in 2012 and 2013?

Response:

No, the unspent approved amounts for 2010 and 2011 will not be spent in 2012 and 2013. Please refer to BCUC IR 1.104.2 for a discussion on the proposed changes to the EEC deferral account mechanism.

3.3 Please complete the following table to show the continuity of EEC Funding:

($000's)	FEI and FEVI Approved 2010	FEI and FEVI Actual Spending 2010	FEI and FEVI Approved 2011	FEI and FEVI Projected Spending 2011	Previously Approved Funding Carried Forward to 2012	FEI and FEVI Incremental Funding Proposed 2012	Total	2012 Proposed Funding	Previously Approved Funding Carried Forward to 2013	FEI and FEVI Incremental Funding Proposed 2013	Total	2013 Proposed Funding
Residential, Commercial, Joint Initiatives and CEO Programs	24,801		24,801									
Affordable Housing	3,000		3,000									
Industrial Interruptible	435		1,875									
Innovative Technologies	2,778		5,625									
Total	31,014	12,600	35,301	25,700				74,500				74,500

Response:

As stated in the response to BCUC IR 1.3.2, funding has not been carried over from 2010 or 2011 to the proposed funding for 2012 or 2013. Therefore, the FEU have removed the "Previously Approved Funding Carried Forward to 2012/2013" and the "Total" columns from the table as provided in the question preamble.

The reference to EEC spending in Section 1.2.2 on Page 11 of the Application (Exhibit B-1) incorrectly identified the 2011 projected spending as $25.7 million. The projected FEU 2011 EEC spending at this time is $19.8 million, as provided in Section 7.1 and 7.2, Schedule 66, Line 10. FEI defines "Spending" in this context to mean actual additions to the EEC rate base deferral account. The table below reflects the actual additions to the deferral accounts in 2010 of $12.6 million and the projected 2011 addition to the deferral accounts of $19.8 million; the numbers presented in the 2010 EEC Annual Report represent commitments made to customers for the provision of incentive funding during 2010 and projected commitments for 2011 and therefore differ from the table below. Although actual deferral account additions in the Innovative Technologies program area (which includes NGV) are showing as $2.252 million for 2010 and $0.735 million for 2011 in the table below, commitments to customers during 2010 were $5.959 million, including approximately $5.587 million for NGV, with projected new commitments to customers for NGV of $3.78 million in 2011.

($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, Commercial, Joint Initiatives and CEO Programs	24,801	8,684	24,801	14,728	6,199	31,000	6,199	31,000
Affordable Housing	3,000	1,660	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	2,778	2,252	5,625	735	5,875	11,500	5,875	11,500
New Initiatives	-	-	-	-	25,000	25,000	25,000	25,000
Total	31,014	12,599	35,301	19,800	39,199	74,500	39,199	74,500

Note: the incremental funding proposed for 2013 as compared to 2011.

4.0 Reference: Executive Summary

Exhibit B-1, Part 1.1, p.1

Rate Sensitivity

4.1 Please complete the following table below demonstrating how rates would need to increase in the following scenarios:

	FEI	**FEVI**	**FEW**	**FEI-Fort Nelson**
Rate increase if natural gas prices =$8/GJ				
Rate increase if natural gas prices =$10/GJ				
Rate increase if natural gas prices =$14/GJ				
Equivalent BC Hydro RIB 2 rate =$8/GJ				
Equivalent BC Hydro RIB 2 rate =$10/GJ				
Equivalent BC Hydro RIB 2 rate =$14/GJ				

Response:

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.[2]

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

- The BC Hydro RIB 2 rate does not impact the determination of rates for Mainland, Whistler and Fort Nelson, and thus is not applicable.

Therefore, rather than showing not applicable or "N/A", the FEU have excluded the FEI, FEW and Fort Nelson columns from the requested table and have provided the table for FEVI only.

Please see the tables below which have been updated to reflect the approximate rate increase that would be required for Vancouver Island under each scenario.

The analysis assumes the following:

- Prices of natural gas identified in the table were known at the time of filing and are reflected in the cost of gas embedded in the forecast cost of service for 2012 and 2013;
- 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; and
- As discussed in Section 1.2.5.1 of the Application (Exhibit B-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 and thus the table reflects not applicable or "N/A".

Table 1: Approximate Rate Increase (Excluding RSDA)

	FEVI		
	2012	**2013**	**Total**
Rate increase if natural gas prices =$8/GJ	15%	7%	23%
Rate increase if natural gas prices =$10/GJ	22%	7%	30%
Rate increase if natural gas prices =$14/GJ	37%	7%	45%
Equivalent BC Hydro RIB 2 rate =$8/GJ	N/A	N/A	N/A
Equivalent BC Hydro RIB 2 rate =$10/GJ	N/A	N/A	N/A
Equivalent BC Hydro RIB 2 rate =$14/GJ	N/A	N/A	N/A

Changes to the BC Hydro RIB 2 rate as provided in the question preamble represent a significant decline in the existing equivalent BC Hydro RIB 2 rate of approximately $27/GJ in 2012 and $30/GJ in 2013.[3] A decline of this magnitude would dramatically increase the competitive challenges that FEVI faces, further accentuating the importance to FEVI of amalgamation and rate harmonization. If such a dramatic change in the competitive environment occurred, FEVI would re-evaluate its rate proposals at that time.

Table 2 below provides the rate increases after applying the RSDA balance to offset the rate increases in Table 1.

[3] Section 1.2.5.1, Figure 1.2-3, page 24, assumes 90% efficiency

Table 2: Approximate Rate Increase, Including RSDA

	FEVI		
	2012	**2013**	**Total**
Rate increase if natural gas prices =$8/GJ	0%	2%	2%
Rate increase if natural gas prices =$10/GJ	0%	17%	17%
Rate increase if natural gas prices =$14/GJ	1%	45%	46%
Equivalent BC Hydro RIB 2 rate =$8/GJ	N/A	N/A	N/A
Equivalent BC Hydro RIB 2 rate =$10/GJ	N/A	N/A	N/A
Equivalent BC Hydro RIB 2 rate =$14/GJ	N/A	N/A	N/A

5.0 Reference: Executive Summary

Exhibit B-1, Part 1.1, p.1

Customer Survey and Promotion

5.1 Please provide a summary of all customer surveys conducted in the year in the table below:

Name of Customer Survey	Cost of Survey	Purpose of Survey	Number of Customers Surveyed

Response:

The table below presents a summary of the customer survey work completed in 2010. Each of these surveys provides important information needed to plan and deliver services to our natural gas customers, will help us forecast natural gas demand and use rates in the long term, and/or develop communications activities needed to serve our natural gas customers.

The costs presented here do not include taxes.

Summary of Customer Surveys Conducted by FEU

Name of Customer Survey	Cost of Survey	Purpose of Survey	Number of Customers Surveyed
Customer Satisfaction Tracking Study	$74,500.00	Measures satisfaction with three customer transactions – meter exchange, gas odour call and new service installation. Used to improve processes/ coaching tool for line managers.	3,500
Residential Customer Satisfaction Study	$45,000	Corporate Scorecard reporting. Reporting to the BCUC.	1200
Small Commercial Satisfaction Study	$22,900	Corporate Scorecard reporting. Reporting to the BCUC.	500
Large Commercial Satisfaction Study	$21,050	Corporate Scorecard reporting. Reporting to the BCUC.	220

Name of Customer Survey	Cost of Survey	Purpose of Survey	Number of Customers Surveyed
Customer Commitment - Residential	$52,000	Benchmark customer satisfaction against peer companies. Identify customer commitment. Evaluate risk of customer defection.	1300
Customer Commitment - Small Commercial	$34,300	Benchmark customer satisfaction against peer companies. Identify customer commitment. Evaluate risk of customer defection.	500
Customer Commitment - Large Commercial	$33,844	Benchmark customer satisfaction against peer companies. Identify customer commitment. Evaluate risk of customer defection.	220
Energy Preferences and End Uses Study	$329,000	Understand fuel and end use preferences. Quantify the penetration of natural gas end uses in newer commercial and residential properties.	1150 (BC residents) 650 (BC businesses)
Natural Gas Safety Awareness	$70,000	Understand public awareness of natural gas safety issues. Track effectiveness of public safety messaging.	1055 (BC residents)
Energy Efficiency Advertising Awareness	$3,200	Effectiveness of Energy Efficiency marketing activities.	500 (BC residents)
Mobile Home Study	$20,000	Determine potential for Energy Efficiency programs for mobile home owners.	500 (BC residents)
Bill Insert Study	$42,000	Understand effectiveness of bill inserts in terms of readership and message recall.	600 (Residential customers) 451 (Small commercial customers)
Evergreening Customer Choice Contracts	$7,200	Focus group to explore customer knowledge of the Evergreening clause in gas marketing contracts	8 (Residential customers)

Name of Customer Survey	Cost of Survey	Purpose of Survey	Number of Customers Surveyed
Furnace Maintenance Program Evaluation	$15,000	Effectiveness of a program to encourage regular furnace maintenance	375 (Residential customers)
Ad Testing	$12,300	Evaluate the effectiveness of print ads and pamphlets. Test their ability to engage readers and convey key messages.	793 (BC residents)
Alternative Energy Survey	$18,000 (charged to the Thermal Energy deferral account)	Assess British Columbians' awareness, knowledge, and attitudes towards emerging energy technologies.	800 (BC residents)
Biogas Communications	$26,700 (charged to the biogas deferral account)	Evaluate different creative approaches, key messages and communication channels for the Biogas program introduction.	516 (BC residents)

5.2 During the Vancouver Winter Olympics in 2010, FEU sponsored the Official Olympic Flame. Can you please clarify the total costs for that sponsorship, the source of the funds and clarify if that cost was fully paid by the Shareholder?

Response:

As explained in Attachment 5.2 containing a letter that was filed with the Commission on February 16, 2010, the Olympic Cauldron was funded by FEI at a cost of $3.21 million in 2009. These assets did not factor into the rate base calculations for determination of customer rates for 2009, 2010 or 2011, as the assets were constructed during 2009 while FEI was under a formula-based approach to determining capital expenditures, and rates for 2010 and 2011 were already set before the Olympic Cauldron was constructed. Starting with 2012, the Olympic Cauldron is included in the rate base of FEI with an opening net book value of $2.889 million, with 18 years remaining of its original 20 year life. The revenue requirement impact of this asset being included in rate base is approximately $350 thousand annually for the forecast period (delivery rate impact of approximately 0.06 percent).

Also as outlined in Attachment 5.2, the ongoing operating and maintenance costs of the Olympic Cauldron are covered by the owner of Jack Poole Plaza. The cost of lighting the cauldron including both gas and labour is approximately $1,000 per hour. The Cauldron is usually lit for approximately 4 hours at a time, and these costs are billed to the owner of Jack Poole Plaza. On rare occasions, such as for the recent Stanley Cup Playoffs, FEI will cover all or part of the cost of lighting the cauldron and fund this through its community investment budget. Community investment is essential to maintaining positive relationships within the community and to be a good corporate citizen within the communities the FEU serve. Apart from the intrinsic value of good corporate citizenship, these investments facilitate community acceptance of the FEU's ongoing operations.

6.0 Reference: Executive Summary

Exhibit B-1, Part 1.1, p.1

Summary of Total Deferrals

Please complete the tables below:

Total Deferral Accounts –end of year ($'000)	**2007**	**2008**	**2009**	**2010**	**2011 (projected)**	**2012 (forecast)**	**2013 (forecast)**
FEI							
FEVI							
FEW							
FEI-Fort Nelson							
Total Deferral Accounts – end of year as a % of total revenue requirements	2007 %	2008 %	2009 %	2010 %	2011 %	2012 (forecast) %	2013 (forecast) %
FEI							
FEVI							
FEW							
FEI-Fort Nelson							

<u>Response:</u>

Please refer to Table 1 below which shows the table as requested. For all tables provided in this response, information for 2007-2010 reflects the actual deferral account balances, rate base and revenue requirements for each year and 2011-2013 reflects the projection and forecasts as provided in this Application (Exhibit B-1).

Table 1: Year End Deferral Accounts and Total Revenue Requirements

Total Deferral Accounts - end of year ($'000)	2007	2008	2009	2010	2011 (projected)	2012 (forecast)	2013 (forecast)
FEI	$ (6,177)	$ (13,679)	$ (34,235)	$ (42,013)	$ (13,315)	$ 43,613	$ 33,536
FEVI	$ 3,388	$ 8,152	$ (2,138)	$ 2,801	$ (8,580)	$ 3,648	$ 4,135
FEW	$ 330	$ (415)	$ 25,882	$ 31,237	$ 30,491	$ 27,346	$ 26,060
FEI-Fort Nelson	$ 154	$ 159	$ (4)	$ 132	$ 25	$ 82	$ 82
Total Deferral Accounts - end of year as a % of total revenue requirements	2007 %	2008 %	2009 %	2010 %	2011 (projected) %	2012 (forecast) %	2013 (forecast) %
FEI	-0.43%	-0.93%	-2.56%	-3.22%	-1.10%	3.50%	2.61%
FEVI	2.02%	4.73%	-1.15%	1.88%	-4.97%	1.87%	1.93%
FEW	3.14%	-4.13%	176.67%	222.82%	259.81%	240.28%	214.08%
FEI-Fort Nelson	3.13%	2.94%	-0.08%	2.69%	0.54%	1.67%	1.64%

The FEU believe that Table 1 above is not reflective of the impact of deferral accounts on revenue requirements for two reasons:

- The mid-year balances of deferral accounts are used to determine rate base (not the end of year balances), and;
- It is the amortization expense and earned return associated with the mid-year balance of the deferral accounts that is included in the revenue requirement, not the mid-year balance itself.

Therefore, two additional tables are provided below which the FEU consider more accurately reflect the impact of deferral accounts on the revenue requirements and rate base. Table 2 provides the total mid-year rate base deferral account balances expressed as a percentage of total rate base for each utility and Table 3 provides the amortization expense of deferral accounts expressed as a percentage of the revenue requirements for each utility.

Table 2: Mid-Year Deferral Accounts and Total Rate Base

Total Deferral Accounts - mid-year ($'000)	2007	2008	2009	2010	2011 (projected)	2012 (forecast)	2013 (forecast)
FEI	$ (14,754)	$ (26,223)	$ (33,778)	$ (33,398)	$ (27,664)	$ 27,407	$ 38,574
FEVI	$ 4,794	$ 6,966	$ 3,007	$ 332	$ (2,890)	$ (1,096)	$ 3,891
FEW	$ 187	$ (43)	$ 14,634	$ 29,440	$ 30,864	$ 27,584	$ 26,703
FEI-Fort Nelson	$ 3	$ 157	$ 79	$ 64	$ 85	$ 54	$ 82
Total Deferral Accounts - mid-year as a % of rate base	2007 %	2008 %	2009 %	2010 %	2011 (projected) %	2012 (forecast) %	2013 (forecast) %
FEI	-0.61%	-1.06%	-1.37%	-1.32%	-1.09%	1.00%	1.38%
FEVI	1.00%	1.36%	0.56%	0.06%	-0.43%	-0.14%	0.48%
FEW	1.11%	-0.26%	46.43%	64.85%	68.75%	65.46%	64.34%
FEI-Fort Nelson	0.06%	3.08%	1.56%	1.18%	1.32%	0.61%	0.90%

Table 3: Deferral Account Amortization and Total Revenue Requirements

Total Deferral Accounts - amortization ($'000)	2007	2008	2009	2010	2011 (projected)	2012 (forecast)	2013 (forecast)
FEI	$ (2,724)	$ (3,076)	$ (72)	$ (2,572)	$ (5,271)	$ 5,928	$ 18,187
FEVI	$ 4,755	$ 3,715	$ 5,664	$ (6,209)	$ 4,350	$ (6,008)	$ 2,310
FEW	$ -	$ -	$ (78)	$ 1,509	$ 940	$ 562	$ 1,143
FEI-Fort Nelson	$ -	$ 30	$ 15	$ (3)	$ 70	$ 5	$ 5
Total Deferral Accounts - amortization as a % of total revenue requirements	2007 %	2008 %	2009 %	2010 %	2011 (projected) %	2012 (forecast) %	2013 (forecast) %
FEI	-0.19%	-0.21%	-0.01%	-0.20%	-0.43%	0.48%	1.42%
FEVI	2.83%	2.16%	3.06%	-4.17%	2.52%	-3.08%	1.08%
FEW	0.00%	0.00%	-0.53%	10.76%	8.01%	4.94%	9.39%
FEI-Fort Nelson	0.00%	0.55%	0.29%	-0.06%	1.50%	0.10%	0.10%

6.1 Does FEU have any established limits for the total maximum value acceptable for deferral accounts? If so, what are they?

Response:

No, the FEU do not have established limits for the total maximum value acceptable for deferral accounts; however, the FEU review deferral account balances on a regular basis and, through our rate setting processes (revenue requirements and quarterly gas cost reporting) and annual reporting, report on actual and forecast balances in deferral accounts to the Commission. For example, some of the largest deferral account balances that are carried by the Companies are reviewed through the quarterly gas cost reporting process. When required, commodity rates are adjusted quarterly to avoid undue growth in the FEU's commodity variance deferral accounts.

Many factors come into play when considering deferral account balances including the nature of the underlying cost, inter-generational equity, whether or not there is a likelihood that the account could swing from a debit to a credit or vice versa in a subsequent year, e.g. RSAM. It is important to ensure customers who benefit from expenditures contribute appropriately to the related costs over a reasonable period of time.

6.2 Does FEU believe all deferral accounts, actual and forecasted, are recoverable through rates?

Response:

The FEU believe that deferral accounts are recoverable through rates if the account has been approved for recovery by the Commission, and if costs have been prudently incurred. The FEU seek Commission approval for the implementation or discontinuation of all deferral accounts, as well as the amortization of the accounts. As directed in Commission Order No. G-7-03, deferral accounts and the continuation of amortization rates continue in force until a change is approved by the Commission.[4]

The process for recovering forecast deferral account balances is aligned with the recovery of actual deferral account balances. As is the practice for BC utilities, rates are set on a forward

[4] BC Gas Utility Ltd., 2003 Revenue Requirement Application, Decision, February 4, 2003, Section 5, Page 41

test-year basis. Therefore, the forecast balances of deferral accounts are initially included in the determination of rates. As actual deferred costs or deferred revenues are incurred, the deferrals reflect actual balances and these are the amounts that are ultimately included in rate base and recovered in rates once they are known.

6.3 How does FEU assess if deferral accounts are impaired? What polices does FEU have regarding deferral accounts?

Response:

The FEU assess deferral accounts for impairment on an annual basis by comparing the costs incurred to the amount that has been approved for recovery.

6.4 Have all deferral accounts undergone an impairment test? If so, when was the last test and what were the findings?

Response:

Please refer to BCUC IR 1.6.3.

Yes, all regulated deferral accounts have undergone an impairment test. The most recent test, as at December 31, 2010, found that no deferral accounts were impaired.

6.5 Does FEU exercise the same cost control on deferral accounts that are trued up to actual compared to approved expenses where the shareholder is at risk for overruns?

Response:

For all types of costs (i.e. O&M, Capital, Deferral), the FEU endeavour to ensure the costs are incurred prudently.

Generally, the FEU employ deferral accounts where it is recognized that the predictability of costs are outside the control of the FEU. Thus, in the case of deferral account costs, cost control can be challenging in certain situations. Examples of such deferral accounts include the property tax variance and pension and OPEB variance deferral accounts. In both these examples, actual expenses may exceed the approved amounts as the result of economic and municipal government factors outside of the FEU's control. As such, it is appropriate and has been accepted by the Commission, that all prudent expenses incurred by the FEU, regardless of the approved amount, be recovered from customers.

7.0 Reference: Rate Mitigation Strategy for Vancouver Island: Amalgamation and Harmonized Rate Structure

Exhibit B-1, Part 1.2.5, p. 23

Asset Impairment

"Figure 1.2-2 provides a 5 year outlook of FEVI cost of service rates and shows an expected rate increase of 20 percent by 2016, as compared to existing 2011 rates. Two scenarios providing variations in gas costs are also shown in Figure 1.2-2 and demonstrate that in the event that high commodity costs are experienced, the expected rate increase doubles to 40 percent by 2016.[16]"

7.1 For Figure 1.2-2, please provide the graph and supporting data in fully functional electronic format.

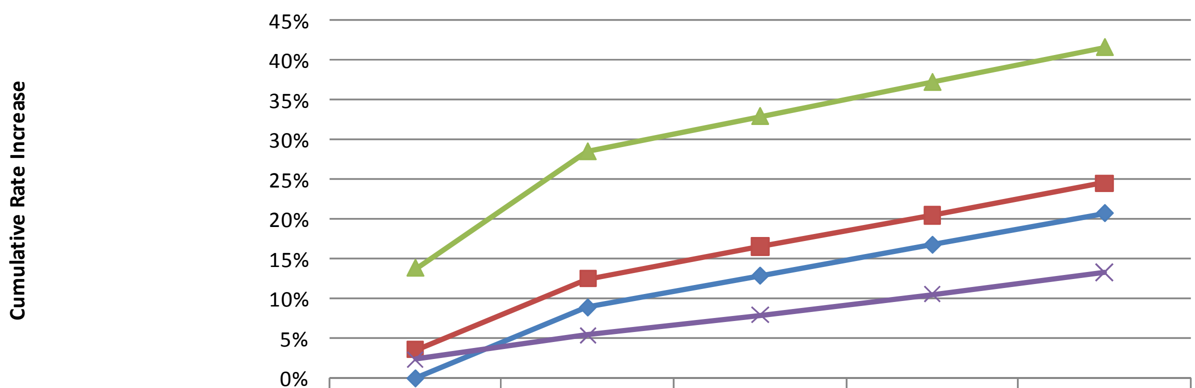
Response:

Please refer to Attachment 7.1.

7.2 Please update Figure 1.2-2 to include a 5 year outlook of FEI cost of service rates. Also include a table comparing the 5 year outlook of the FEVI and FEI cost of service rates.

Response:

Figure 1.2-2 as provided on page 23 of the Application (Exhibit B-1) has been revised to include an outlook of the FEI five-year forecast of changes to the cost of service rates. For comparison with the FEVI forecast, commodity costs have been included. The commodity costs for FEI assume the same inflation as FEVI (please refer to BCUC IR 1.7.1, Attachment 7.1). This chart assumes no amalgamation of the FEU.



	2012	2013	2014	2015	2016
FEVI, Base Case Cost of Gas	0%	9%	13%	17%	21%
FEVI, Moderate	4%	12%	17%	20%	25%
FEVI, High	14%	29%	33%	37%	42%
FEI	2%	5%	8%	11%	13%

As demonstrated in the chart above, the expected annual increases to the FEI cost of service are generally aligned with the FEVI base case scenario forecast, reflecting an assumed annual increase aligned with inflation in the delivery rate, perpetuating the existing rate differential between FEVI and FEI of approximately $6.0 per GJ for a Residential customer.[5]

Please note that the rate increases provided in this response are high level approximations and may not reflect the forecast cost of service for 2014-2016 or rate proposals that are determined in subsequent revenue requirement applications or regulatory proceedings.

[5] Exhibit B-1, Section 1.2.5.1, Page 21

8.0 Reference: Rate Mitigation Strategy for Vancouver Island: Amalgamation and Harmonized Rate Structure

Exhibit B-1, Part 1.2.5.1, p. 24; TGVI 2010-2011 Revenue Requirements and Rate Design Application (TGVI 2010-2011 RRA), BCUC 2.32.1.1

Asset Impairment

"Based on these figures it is evident that FEVI will be more competitive under an amalgamated scenario than left as a standalone utility.

FEW in many regards has similar challenges as FEVI with respect to remaining competitive from a 'price point' perspective vis-a-vis alternative energy options, e.g., electricity. FEW also has a small customer base over which to recover the costs of maintaining natural gas service." (Exhibit B-1, p. 24)

"In a non-regulated company, the need for acceleration in amortization rates may be a possible indicator of impairment triggering a valuation test. However, for a regulated entity a more appropriate indicator of possible impairment is more likely to be its recoverability from ratepayers. The recent exposure draft on rate regulated activities indicates that there may be situations where the net effect of the regulatory assets and regulatory liabilities an entity recognizes will result in significant increases in future rates to be charged to customers. A significant increase in an entity's future rates may create a strong incentive for customers to reduce their consumption or switch to an alternative. When it is not reasonable to assume that an entity will collect sufficient revenues and earn a fair return, this may be an indicator of impairment." (TGVI 2010-2011 RRA, BCUC 2.32.1.1)

8.1 Have FEVI and FEW reached the stage where asset impairment testing should be considered ("when it is not reasonable to assume that an entity will collect sufficient revenues and earn a fair return, this may be an indicator of impairment")? Please explain why, or why not.

Response:

FEVI and FEW have in place financial reporting processes that monitor for asset impairment on an annual basis. FEVI and FEW have not reached the stage where asset impairment should be considered. FEVI and FEW do not have any assets currently in impairment.

The Companies would like to clarify that asset impairment is not a driver behind the Companies' plans to amalgamate. While there continues to be competitive challenges within the FEVI and

FEW service regions, amalgamation will bring benefits to these regions, such as new service offerings, in addition to providing rate relief. The rationale for amalgamation will be fully discussed in the Amalgamation and Rate Design Phase 'A' application to be filed later this year.

9.0 Reference: Rate Mitigation Strategy for Vancouver Island: Amalgamation and Harmonized Rate Structure

Exhibit B-1, Part 1.2.5.1, p. 23; Clean Energy Act (CEA), Part 2

Amalgamation

"In the pending Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011, FEU will make the case that amalgamation of FEVI with the other FEU companies, 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." (Exhibit B-1, p. 23)

9.1 Please discuss FEU's amalgamation proposal with respect to the CEA. The Parts of the Clean Energy Act (CEA) to be considered are as follows:

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

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

(g) to reduce BC greenhouse gas emissions

- (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
- (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
- (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
- (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
- (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;

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

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

Response:

The primary driver of amalgamation and postage stamping is to address upward pressure on rates in Vancouver Island and the competitive position of Whistler. This should be the paramount consideration in assessing the application when it is brought forward. Please see the responses to BCUC IRs 1.9.2 and 1.9.3 which discuss the impact of amalgamation on the energy objectives cited above.

9.2 Will lower FEVI and FEW rates inhibit the development and use of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources? If not, why not?

Response:

The FEU do not believe that the adoption of rate harmonization / postage stamping will have an impact on the development and use of innovative technologies in BC that support energy conservation and efficiency and the use of clean or renewable resources. The provincial energy objectives in the *Clean Energy Act* are Province-wide objectives. FEI has been supportive of the adoption of energy conservation and the use of innovative technologies for the benefit of its customers, who are the majority of the natural gas customers in the Province. Amalgamation will result in an increase in rates to FEI customers, and therefore, the rationale for adoption of conservation and efficiency and the use of renewable resources is not in any way diminished for the large majority of the Province's gas customers.

By amalgamating and harmonizing rates, while there is a rate reduction for FEVI and FEW customers that may reduce the relative benefit to conservation, there continues to be the same rationale for efficiency and conservation that currently exists and will continue for the FEI customers. The common rates and programs emerging from amalgamation and rate harmonization / postage stamping will provide a more consistent basis for the FEU to pursue provincial energy objectives, including the use of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.

Further, FEVI will be making the case in seeking amalgamation that the objective of avoiding significant rate increases for FEVI customers in the short term should be the primary consideration in the assessment of public interest, and GHG emission impacts or innovative technologies are not sufficiently significant to weigh in one direction or another on amalgamation.

9.3 Will lower FEVI and FEW rates encourage consumers to choose natural gas instead of electricity? If yes, will this increase greenhouse gas emission in British Columbia. If not, why not?

Response:

The FEU expect that amalgamation and rate harmonization / postage stamping will positively impact the use of natural gas and customer attachments on Vancouver Island and in Whistler but do not believe that there will be material impacts in the Province as a whole. In other words, amalgamation and rate harmonization / postage stamping will not have a significant net impact in BC overall on customers using natural gas over electricity or on GHG emissions in BC. There are two primary reasons why the FEU believe this:

1. There are a number of factors involved in a customer's energy purchasing decision. Energy rates are one consideration in that decision; other factors include the capital cost to install equipment, ease of use and reliability. The position of the decision maker in regard to the energy equipment being installed in a home is also relevant. Builders and developers are very conscious of whether they will be able to recover the incremental cost of the furnace, ducting and other equipment in the selling price of a gas-heated home. As illustrated in FEI's 2010-2011 RRA, the capital cost to install equipment is a key hurdle that must be overcome by a customer:

   > *"Thus, direct use of natural gas for certain applications must overcome two hurdles before the buyer will make a commitment to investing in natural gas equipment. One is the economic test, comparing the historical and future natural gas operating costs and capital cost versus the competitive alternative."*[6]

   Amalgamation and rate harmonization / postage stamping will have a material impact on the operating costs (i.e. the rates) going forward for gas space and water heating in the FEVI and FEW service territories but the incremental capital costs will be unaffected and will therefore continue to pose the same hurdle following amalgamation and rate harmonization / postage stamping. The positive impacts on customer attachments and gas use from lower rates in FEVI and FEW will be moderated by other hurdles such as the higher upfront costs of natural gas energy equipment.

[6] FortisBC Energy Inc. (formerly Terasen Gas Inc.) 2010-2011 RRA, page 56

In the case of customers with existing energy equipment, for the same reasons as customers installing energy equipment in new building stock, they have a similar economic decision to make with respect to replacing their existing equipment with more expensive natural gas equipment. Therefore, this hurdle also holds true with respect to existing energy customers deciding whether to switch energy source (e.g., from electricity to gas).

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.

In sum, the FEU believe that amalgamation and rate harmonization / postage stamping will be justified based on the rate impacts to customers. Any impacts on overall greenhouse gas emissions in BC are not expected to be material and do not outweigh the benefit to customers of avoiding significant rate increases when the Royalty Payments expire.

9.4 Does natural gas have higher greenhouse gas emissions than electricity?

Response:

There is no single answer to this question. It could be argued, however, that serving end-use energy needs with electricity generates higher greenhouse gas emissions than serving the same end-use with natural gas. Information must be known about the specific circumstances in order to make an assessment of this. For example, information must be known about what the energy is used for and the relative efficiencies of natural gas or electricity serving that use. How electricity is generated in a given area and the interconnectedness with neighbouring jurisdictions are also important to know. For instance, most jurisdictions in North America have a high percentage of fossil-fuel (coal or natural gas) generation in their supply resource stack. Electricity generated from fossil fuels is much more GHG emission intensive than using natural gas directly to serve customers' thermal energy requirements. So in most areas of North

America electricity arguably has higher GHG emissions than natural gas to meet the same end-use energy requirements. The FEU also believe that an appropriate comparison of emissions from natural gas and electricity must be based on the marginal GHG emission impacts of substituting natural gas for electricity or vice versa, rather than comparing the average GHG intensity of electricity generation in an area to the average GHG intensity of serving energy needs with natural gas.

In two past regulatory proceedings[7] before the Commission the FEU have argued that using natural gas and alternative energy sources to meet the thermal energy needs in the Province will enable BC's renewable electricity resources to be used to displace coal-fired and gas-fired generation in neighbouring jurisdictions. Employing this approach would result in net lower GHG emissions in the broader region (BC and neighbouring jurisdictions), although there may be increased GHG emissions within BC (depending on how much thermal energy demand is met by alternative energy sources and how much by natural gas). The FEU continue to believe that the direct use of natural gas in thermal applications in BC contributes to regional GHG emission reductions, notwithstanding that the *Clean Energy Act* places a key focus on GHG emission reductions within BC (for example, a fuel switching program from electricity to natural gas is not permitted as a demand-side measure if it would result in higher GHG emissions in BC). That said, the planet's atmosphere does not respect geo-political boundaries and common sense dictates that net lower regional emissions are preferable to net higher regional emissions accompanied by lower BC generated emissions.

Natural gas has been a very important contributor to BC's energy resource mix, providing about the same amount of end-use energy as electricity in the Province. The FEU believe that natural gas will continue to be an efficient and appropriate energy source for use in thermal applications in BC for many years to come. Also, expansion of natural gas use in sectors such as transportation will contribute to greenhouse gas emissions reductions in BC while at the same time providing benefits for natural gas ratepayers and for the BC economy as a whole. The policy and legislative focus in BC on GHG emission reductions has placed an increased emphasis on alternative energy solutions but natural gas continues to be part of the overall energy mix as indicated in the Province's 2007 Energy Plan, which states on page 21:

> *It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. <u>There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal</u>. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province"* [emphasis added].

7 BC Hydro 2007 Rate Design Application and BC Hydro 2008 LTAP Application

10.0 Reference: Approval of Consolidated Cost of Service is A Necessary First Step

Exhibit B-1, Part 1.2.5.2, p. 25

Consolidated Cost

> A first step towards postage stamp rates for 2013 is to obtain Commission approval of an amalgamated cost of service, reflecting the combined costs of the three entities. The FEU believe, for the reasons set out below, that obtaining approval of an amalgamated cost of service as part of the present Application (rather than doing it as part of the Fall 2011 Amalgamation and Phase 'A' Rate Design Application) is most efficient:

10.1 What section of the *Utilities Commission Act* gives the Commission the ability to approve this request?

Response:

Sections 59-61 of the *Utilities Commission Act*, which provide the Commission with ratemaking authority, enable the Commission to approve the requested amalgamated cost of service as a first step in the ratemaking process that will be completed only if amalgamation is later approved. As explained in section 1.2.5.2 of the Application (Exhibit B-1), the amalgamated cost of service reflects the combined costs of the FEU. Approval of the amalgamated cost of service provides the necessary platform for performing the cost of service analysis necessary 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 requirement issues in this process.

10.2 Does the Application characterize the approval of amalgamated cost of service as a policy decision?

Response:

No, the Application makes clear that the Commission's approval of the amalgamated cost of service is a first step in a revenue requirements (rate setting) process for an amalgamated entity that would only be completed (i.e. rates would only be set based on that cost of service) if the Commission approves amalgamation in a later process. Determining the cost of service for a public utility is the core of the Commission's traditional ratemaking activities, and does not involve setting Commission "policy".

The only difference in this case from what the Commission does in the normal course of rate setting is that the cost of service at issue, in this case, is that of four utilities that will later seek to amalgamate. However, the Companies have stated in the Application that the Commission decision on a combined cost of service will not pre-determine the merits of the amalgamation of the FEU entities. The orders sought are explicit in this matter. Approval for amalgamation of the utilities will be applied for and determined at a later date under section 53 of the *Utilities Commission Act*. The explicit caveat in the orders sought makes the determination of a combined cost of service the same, in substance, to what the Commission does in the normal course of rate setting.

10.3 Does FEU's management propose to address the amalgamated cost of service within a negotiated settlement?

Response:

This response responds to BCUC IRs 1.10.3, 1.10.4, and 1.10.5.

Yes, the Companies do propose to include the amalgamated cost of service issue in the Negotiated Settlement Process ("NSP") if an NSP is determined to be the appropriate regulatory process for resolving other parts of this Application.

The amalgamated cost of service can and should be part of the NSP. Particularly, including the amalgamated cost of service within an NSP is appropriate under the Commission's guidelines on NSPs:

a) The amalgamated cost of service reflects the sum of the total cost of service for FEI, FEVI, FEW and Fort Nelson, with some adjustments (see schedule 2, Application Amendment, Exhibit B-1-2, submitted on May 16, 2011). Any items agreed to in an NSP with respect to any of the individual utilities' cost of service will flow through to the amalgamated cost of service. As the cost of service of the individual entities so closely relates to the amalgamated cost of service, it is natural and efficient that they be considered together.

b) The customer classes or other groups that are likely to be affected by the amalgamated cost of service decision are the same classes and groups that will be affected by a final Negotiated Settlement Agreement. There is, therefore, no reason to exclude the amalgamated cost of service issue from an NSP on the basis of lack of representation by affected customer classes or groups.

c) The issue on the amalgamated cost of service is the amount of savings and costs that can be attributed to amalgamation. This does not raise any particular policy issues. In particular, the approval of the amalgamated cost of service does not constitute a pre-determination of whether the amalgamation of FEU entities would be beneficial in the public interest. The amalgamation of the FEU will be addressed in a subsequent application by the Companies under section 53 of the *UCA*. Please also see the response to BCUC IRs 1.10.1 and 1.10.2.

In summary, determining the cost of service for a public utility is the core of the Commission's traditional ratemaking activities. The only difference in this case from what the Commission does in the normal course of rate setting is that the cost of service at issue, in this case, is that of four utilities that will later seek to amalgamate. The explicit caveat in the orders sought makes the determination of a combined cost of service the same, in substance, to what the Commission does in the normal course of rate setting. As cost of services issues are routinely addressed in NSPs, and would be addressed in an NSP in this proceeding on an individual utility basis in any event, the FEU believe that the issues regarding the combined cost of service can and should be addressed in the same NSP.

10.4 Would the requested approval for amalgamated cost of service be appropriate for inclusion in a negotiated settlement under the existing Commission guidelines?

Response:

Yes. Please see the response to BCUC IR 1.10.3.

10.5 Would FEU be opposed to addressing the approval of amalgamated costs as a separate process, such as through a written hearing?

Response:

The FEU believe that an NSP process is most efficient in this proceeding, including for the determination of an amalgamated cost of service. The analysis involved in the determination of the amalgamated cost of service is, in substance, the same as what would be undertaken in respect of determining the cost of service in an NSP by each utility. The evidence will largely overlap. Please see the response to BCUC IR 1.10.3.

A written hearing, as opposed to an oral hearing, would be appropriate if an NSP is unsuccessful.

10.6 If this request for amalgamated costs was not approved, could the Commission utilize the cost information presented in this application during the amalgamation proceeding, if deemed appropriate at that time?

Response:

Yes. As explained in Section 1.2.5.2 of the Application (Exhibit B-1) and demonstrated in Tab 7.5, Schedule 2 in the Amendment to the Application filed on May 16, 2011 (Exhibit B-1-2), the amalgamated cost of service reflects the sum total of cost of service for FEI, FEVI, FEW and Fort Nelson, with certain adjustments (Schedule 2, Exhibit B-1-2). The Commission could use the cost information in the amalgamation proceeding, with adjustments where necessary, if it were filed in that proceeding. In the event that the amalgamated cost of service is not approved, the Companies would present information in the amalgamation proceeding to establish cost of service for the amalgamated entity that will reflect any appropriate adjustments from the total cost of service of the individual utilities.

However, the Companies are seeking Commission approval of the amalgamated cost of service as it enhances regulatory efficiency to address the issues relating to the cost of service under an amalgamation scenario as part of the present Application, without predetermining the merits of amalgamation or a harmonized rate structure. This approach will ensure that the future rate design for an amalgamated entity can be assessed in a subsequent rate design application based on known 2013 costs. Additionally, since it is likely that this Application will be still pending by the time the Companies file the anticipated application for amalgamation, it is better to have the present panel dealing with the amalgamated cost of service issue rather than having two panels in two different proceedings considering the same evidence with respect to the cost of service of the utilities.

10.7 If the amalgamation is approved and FEU operates under a single structure, how would items such as capital structure, return on equity and interest be calculated differently?

Response:

If amalgamation is approved, items such as capital structure, return on equity and interest would be calculated in the same manner as today for each of the individual entities. That is, the calculation method will remain the same although the inputs or rates may change subject to Commission Approval. Please refer to Schedules 6, 45 and 47 of Tab 7.5 of the Application (Exhibit B-1-2) for information relating to the calculation of capital structure, return on equity and interest for the amalgamated cost of service. Also, please refer to BCUC IR 1.10.8 for additional information relating to return on equity and interest which also outline the forecast reduction to short-term interest expense upon amalgamation of approximately $2.1 million.

10.8 Could the Utility seek approval for an amalgamated cost of service of the FEU before interest or ROE?

Response:

Yes, the FEU could seek approval for an amalgamated cost of service before interest or ROE. However, the FEU believe that this is not necessary for three main reasons:

1. **The FEU have not embedded any changes to the current Commission Approved cost of equity applicable to the stand alone entities[8]:**

   The amalgamated cost of service, as provided in this Application and demonstrated on Schedules 1 through 6 of Tab 7.5, has been determined using the weighted average approved return on equity and portion of rate base for FEI, FEVI, FEW and Fort Nelson [9]. In the stand alone forecast cost of service for each entity, the FEU have not presumed any changes to ROE in absence of Commission Approval; determining a weighted average ROE for the amalgamated entity is consistent with this approach.

8 Return on equity as approved through BCUC Order No. G-158-09

9 A small impact of $64 thousand occurs upon amalgamation as a result of a change in rate base due to working capital and the rounding of the weighted average return on equity to two decimal places. Please see Section 7, Tab 7.5, Schedule 6, Page 775

2. **The FEU will seek approval to flow through Commission approved ROE and capital structure changes to the cost of service and rates as they apply:**

   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.

3. **All forecast impacts to interest expense are reflected in the amalgamated cost of service:**

   Savings of approximately $2.2 million associated with short-term interest expense are forecast based on approximately $230 million of amalgamated short-term debt being financed at the FEI short-term debt rate. The actual savings amount will depend on the amount of principal that will shift to the lower FEI rate as well as the FEI unfunded debt rate, both of which will be updated in the upcoming Evidentiary Update. The FEU believe it is appropriate to use the FEI short-term debt rate because it is likely that only one credit facility would be required upon amalgamation. The amalgamated capital structure results in a change to the effective debt rate associated with Series B, resulting in an immaterial decrease to the amalgamated long-term interest expense of $24 thousand. The FEU do not anticipate any other changes to long-term debt issuances or retirements as a result of amalgamation; therefore, additional costs or savings associated with long term interest expense are not forecast.

Approval of an amalgamated cost of service before interest and ROE would need to consider implications to tax expense because changes in ROE and interest will impact the determination of tax expense embedded in the amalgamated cost of service.

The FEU believe that the amalgamated cost of service can be approved as filed in the Application, without pre-determining the merits of amalgamation, harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

10.9 When did the Companies perform their last cost of service studies and when do the Companies plan to have their next studies performed?

Response:

The Companies are in the process of completing their cost of service studies for the amalgamated FEU that will provide support for the rate design that will be filed as part of the Amalgamation and Rate Design Phase 'A' Application to be filed later this year.

Below are the years and applications in which the cost of service studies for each entity was last undertaken:

- FortisBC Energy Inc. – 2001 (BC Gas Utility Ltd 2001 Rate Design Application)
- FortisBC Energy Inc. Fort Nelson Service Area – 2008 (an Information Request response in the '*Terasen Gas Inc. - Fort Nelson Service Area Application for changes to Revenue Stabilization Adjustment Mechanism Rider and Delivery Rates Effective January 1, 2008*' application)
- FortisBC Energy (Vancouver Island) Inc. – 2009 (Terasen Gas (Vancouver Island) Inc. Application for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008)
- FortisBC Energy (Whistler) Inc. – N/A – cost of service studies have not been previously filed.

11.0 Reference: Organization Performance

Exhibit B-1, Part 3.1.2, p. 35 and Appendix B-3

Service Quality Indicators

Table 3.1-2: Service Quality Indicators		**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Customer Performance Indicator	**Benchmark**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**
Independent Customer Satisfaction Survey	Compared to prior years	73.90%	73.90%	77.20%	77.90%	79.30%	79.70%	80.10%	80.00%
Number of Customer Complaints to BCUC	Compared to prior years	101	191	121	152	130	90	58	26
Number of Third Party Distribution System Incidents	N/A	1,459	1,492	1,457	1,508	1,545	1,574	1,322	1,246

11.1 Using the information in Appendix B-1 complete the following tables:

FEI Operational Metrics

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Outages Caused by Third Party/Total Pipeline (km)								
Outages /Total Average Customers								
Total Average Customers/FTE								
Rate Base, mid-Year/Total Average Customers								

FEVI Operational Metrics

	2003	2004	2005	2006	2007	2008	2009	2010
Outages /Total Average Customers								
Total Average Customers/FTE								
Rate Base, mid-Year/Total Average Customers								

Also provide the tables in fully functional electronic format.

Response:

Please note that the requested data is not provided in Appendix B-1 as referenced in the question. The data can be found in the Application (Exhibit B-1) as follows: Appendix D-3 was referenced for average customers, Appendix D-4 was referenced for FTE information and Appendix B-3 was referenced for Outage statistics.

Please refer to Attachment 11.1 for the fully functional excel worksheet.

FEI Operational Metrics	2003	2004	2005	2006	2007	2008	2009	2010
Outages Caused by Third Party/Total Pipeline (km)	0.039	0.039	0.037	0.036	0.038	0.038	0.033	0.032
Outages /Total Average Customers	0.002	0.002	0.003	0.003	0.004	0.003	0.002	0.003
Total Average Customers/FTE	648	716	725	758	753	734	715	676
Rate Base, mid-Year/Total Average Customers	$ 2,918	$ 2,958	$ 3,042	$ 3,042	$ 2,972	$ 2,997	$ 2,957	$ 3,010

FEVI Operational Metrics	2003	2004	2005	2006	2007	2008	2009	2010
Outages /Total Average Customers	0.002	0.002	0.002	0.003	0.003	0.003	0.002	0.002
Total Average Customers/FTE	367	471	529	698	879	958	993	982
Rate Base, mid-Year/Total Average Customers	$ 5,810	$ 5,604	$ 5,520	$ 5,471	$ 5,360	$ 5,499	$ 5,537	$ 5,536

12.0 Reference: Generally Accepted Accounting Principles (GAAP) Used in Determining Revenue Requirements

Exhibit B-1, Part 3.2, p. 40

Code of Accounts

12.1 Please provide a fully searchable electronic copy of the latest version of the FEU code of accounts.

Response:

Please see Attachment 12.1 for a copy of the Chart of Accounts. Please note that the Chart of Accounts is for all of the companies in the FortisBC Holdings Inc. group, including both utilities and NRBs.

13.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.1.6, p. 53

Mainland Taxes

13.1 Table 3.3-5 summarizes the changes in tax expense for 2012 and 2013 and cross-references to Part 7.1 to 7.4, Schedules 30 to 35 for details. Please identify the items in Schedules 30 to 35 that are included in the $3.4 million of "Other" taxes for 2013 as shown in Table 3.3-5 or provide the reference for the location in the Application for further detail on the amount.

Response:

Table 3.3-5 as included on page 54 of the Application (Exhibit B-1) inadvertently categorized the explanation of all tax expense changes in 2013 as "Other". A revised version of Table 3.3-5 is provided below.

Table 3.3-5: REVISED Components of 2012 and 2013 Tax Expense Changes

FEI (2011 Approved vs. Forecast)			
($ millions)	**2012**	**2013**	**Total**
Reduction in Tax Rate	$ (2.0)	$ (0.5)	$ (2.5)
Increase in CCA Deductions	(13.1)	(0.8)	(14.0)
Removal Cost Deduction	(4.5)	(0.1)	(4.7)
Pension and OPEB	(1.5)	(0.2)	(1.7)
Changes in Amortization Expense	4.0	4.4	8.5
Changes in Earned Return	1.5	0.7	2.2
Other	0.2	0.1	0.3
	$ (15.5)	$ 3.7	$ (11.8)

Details of the changes in tax expense as well as the adjustments to taxable income can be found in the Application, Section 7.1, Schedules 30 to 35 (Exhibit B-1).

13.2 The total tax expense changes shown in Table 3.3-5 do not agree to the change shown in Part 7.1, Schedules 5 and 6 for 2012 and 2013 respectively. Schedule 5 shows a change in the 2012 forecasted tax expense from 2011 projected of ($6,857,000) compared to the ($15.5 million) shown in Table 3.3-5. Likewise, Schedule 6 shows a change in the 2013 forecasted tax expense from 2012 forecast of $5,682,000 compared to $3.7 million shown in Table 3.3-5. Please reconcile the differences.

Response:

To determine the impact on the revenue deficiency or surplus of a change in the revenue requirement, the forecast must be compared to the approved amount embedded in existing rates for that revenue requirement component.

Therefore, to determine the impacts of changes in tax expense of $(15.5) million in 2012 and $3.7 million ($(11.8) million total) in 2013, the forecasts were compared to the approved tax expense of $32.516 million in 2011 (Schedule 30 of Section 7.1) which include approved adjustments to taxable income of $(9.7) million (Schedule 33 of Section 7.1) and not the projected 2011 amounts as referenced in preamble to the question.

The following table provides a reconciliation of the $(15.5) million in 2012 and $3.7 million in 2013:

2012 and 2013 Tax Expense Changes

Line	Particulars	2012	2013	Total	Reference
1	Forecast Income Tax	$ 24.5	$ 5.7	$ 30.2	Section 7.1, Schedule 31
2	Less Approved 2011 Income Tax	32.5	-	32.5	Section 7.1, Schedule 30
3	Less Tax Expense Impact of Depreciation Changes	7.5	2.0	9.5	Section 7.1, Schedule 1
4	Tax Expense Change	$ (15.5)	$ 3.7	$ (11.8)	

Note that Line 3 (Tax Expense Impact of Depreciation Changes) is excluded from the summary of income tax changes included in Section 3.3.1.6 since it is included in the analysis of the total impact of depreciation changes discussed in Section 3.3.1.4.

14.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.2.4, pp. 57-58; Part 3.4.2, p. 72

Vancouver Island Transportation Costs

In Table 3.3-7, the motor fuel and social services taxes on compressor and station fuel increase 268% from $292,000 in 2011 to $782,000 in 2012.

The costs related to the BC Hydro Capacity Rights drop 35% from $375,000 in 2011 to $244,000 in 2012. *“For purposes of this submission, the forecast annual cost related to this capacity right is $244 thousand for 2012 and 2013.”*

“In this Application, Vancouver Island is seeking approval for a continuation of the existing rates for sales customers, Whistler and BC Hydro.” [Ref: p. 72]

14.1 Please explain the reason for such a large increase in the taxes on Compressor and Station Fuel. Is this an increase in the tax rates or the impact of a full year of operation at Mt Hayes?

Response:

The increase in taxes on compressor and station fuel in Vancouver Island, as provided in Table 3.3-7 and in Section 7.2 of the Application (Exhibit B-1), is incorrect as we inadvertently double counted Motor Fuel Tax (“MFT”) and Odorant Costs in the 2011 projection as well as the 2012 and 2013 forecast of transportation costs.

Taxes on compressor and station fuel have been revised from $782 thousand to $240 thousand in 2012 and from $784 thousand to $242 thousand in 2013

Table 3.3-7: REVISED Transportation Cost Forecast for 2012 and 2013

$ thousands **Transportation Costs**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
FEI Wheeling Agreement	3,455	3,456	3,464
BC Hydro Capacity Right	375	244	244
Taxes on Compressor and Station Fuel	292	240	242
Total Transportation Expenses	4,122	3,940	3,950

Corresponding amended financial schedules will be filed when FEVI provides an Evidentiary Update.

14.2 Please confirm the reduced cost of the BC Hydro Capacity Right is as calculated under a contract provision or provide the basis for the reduced costs from 2011 to 2012/13.

Response:

The BC Hydro Capacity Right Payment is calculated in accordance with Article 5 of the Peaking Agreement between BC Hydro and FEVI. The key factors that affect the calculation are the Maximum Curtailment Volume and the Distillate Index Price.

As per Article 3.5 of the Peaking Agreement, the maximum curtailment volume for the period of November 1, 2010 to April 1, 2011 was to increase to 150,000 GJs from 100,000 GJs. FEVI did not require the 150,000 GJs and BC Hydro agreed to reduce the maximum curtailment volume for the period back to 100,000 GJs. The resulting impact of the reduction in the maximum curtailment volume reduces the Capacity Right Payment by approximately by 1/3 or $10,000 per month.

15.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.3, pp. 61-64

Summary of Whistler Revenue Requirements

Figure 3.3-9 Whistler Revenue Deficiency Components

The increases in Whistler revenue requirements that drive the additional effective base rate delivery increase to residential customers of 11.9 per cent in 2013 are the net $605,000 increase in amortization and the $208,200 net increase in taxes. [Ref: p. 62]

Part 3.3.3.4 - Depreciation and Amortization Expense

"The decrease in 2012 and corresponding increase is [sic] 2013, is largely attributable to the one year amortization of the credit balances in the Pipeline Cost Variance Account of $434 thousand and the Interest Variance account of $329 thousand." [Ref: p. 64]

Part 3.3.3.6 - Taxes

"Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $133 thousand and an increase in 2013 of $200 thousand." [Ref: p. 64]

15.1 Please explain why the amortization of the credit balances in the Pipeline Cost Variance Account and the Interest Variance Account are only reflected in 2012 and not 2013?

Response:

As discussed in Section 6.3.5.3 of the Application (page 408 of Exhibit B-1) and pursuant to BCUC Order No. G-71-11, the amortization of the Pipeline Cost Variance Account is a one-year period commencing January 1, 2012. Therefore, the full credit balance of this account is fully amortized through 2012 rates.

As reflected on Schedule 68 in Section 7, Tab 7.3 of the Application (Exhibit B-1), the credit balance in the Interest Variance Account was amortized over the existing approved one-year period, in accordance with BCUC Order No. G-35-09. However, as discussed in Section 6.3.3.5 of this Application (page 402 of Exhibit B-1), FEW has requested approval to amortize the Interest Variance Account over a three-year period for consistency with Mainland; therefore, the financial schedules in Section 7.3 should have reflected the proposed amortization period of three years rather than the currently approved amortization period of one year.

Amended financial schedules will reflect the proposed three-year amortization period of the Interest Variance Account when FEW files an Evidentiary Update.

16.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.3.3, p. 63

Whistler Transportation Costs

"Whistler transportation costs reflect the charge paid by Whistler to Vancouver Island for gas transportation service on the Whistler Pipeline. The transportation costs are forecast at approximately $2.6 million per year for 2012 and 2013, increasing the revenue requirement by $127 thousand in 2012."

16.1 Please confirm the increase of $127 thousand is from Approved 2011 of $2,458 thousand to Projected 2011 of $2,585 thousand, which carries through to 2012 and 2013, and explain the reason for the projected increase during 2011.

Response:

As discussed in response to BCUC IR 1.14.1 regarding FEVI taxes on compressor and station fuel, the Motor Fuel Tax, Odorant Cost, and UAF components in FEW's transportation costs were inadvertently double counted and result in an overstatement of transportation costs. The transportation costs for FEW have been revised and are forecast to be $2,525 thousand and $2,553 thousand in 2012 and 2013, respectively.

The determination of the Whistler transportation costs for 2012 and 2013 is as follows:

Line	Particulars		2011 Approved	2012 Forecast	2013 Forecast
1	TGVI Transportation Charge ($/GJ per day)	Per Contract	$ 0.958	$ 0.958	$ 0.958
2					
3	Daily Contract Demand	Per Contract	7,030	7,200	7,300
4	Number of Days per Year		365	366	365
5	Annual Contract Demand	Line 3 x Line 5	2,565,950	2,635,200	2,664,500
6					
7	Total Transportation Charge ($000/annum)	Line 1 x Line 5 / 1,000	**$ 2,458.2**	**$ 2,524.5**	**$ 2,552.6**

Amended financial schedules reflecting this change will be filed when the FEU file an Evidentiary Update.

17.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.4.2, p. 67; Order G-27-11

Fort Nelson Depreciation Expense – Muskwa River Crossing Project

"Approval of the proposed 2011 capital expenditures including $3,015,650 of capital costs (excluding AFUDC) related to the Muskwa River Crossing Project (Project) as requested by TG Fort Nelson in the Evidentiary Update subject to conditions described in the Reasons for Decisions accompanying this Order. Further, the Commission approves the inclusion of Project costs, as presented in the Evidentiary update, in 2011 ratebase. All Project costs may be subject to prudency review by the Commission upon completion of the Project. However, the total amortization/depreciation projected in this Application shall be recorded as a reduction to the carrying amount of the Project Assets in 2012. The Project assets shall not attract AFUDC after the projected in-service date included in this Application." [Ref: Commission Order G-27-11]

17.1 Please confirm the Fort Nelson depreciation and amortization expense for 2012 and 2013 properly reflect the direction of Commission Order G-27-11.

Response:

Fort Nelson confirms that the depreciation expense for 2012 and 2013 properly reflects the direction of Commission Order No. G-27-11.

In this Application (Exhibit B-1), the Muskwa River project is projected to be in-service by October 31, 2011 consistent with the in-service date included in the Fort Nelson 2011 Rates Application referenced in the preamble. The result of this is that the depreciation expense recorded for the months of November and December of 2011 and included in the determination of rates for Fort Nelson for 2011 reduces the 2012 opening net book value of the Muskwa River project, as required by Commission Order No. G-27-11. The table below provides a reconciliation of the 2011, 2012, and 2013 additions (excluding AFUDC and capitalized overhead) to the Transmission Mains account reflected on line 6, column 4 of Schedule 44, Schedule 47 and Schedule 50, in Section 7.4 (Exhibit B-1). This table demonstrates that additions of $3.016 million have been included with respect to the Muskwa River project and used as the basis for the determination of depreciation expense, consistent with the amount approved for inclusion in rate base as referenced in Commission Order No. G-27-11.

Plant Additions: Transmission Mains- Account 465-00				
($ Thousands)	**2011**	**2012**	**2013**	**Total**
Muskwa River Project	2,866	150	-	**3,016**
Laterals	-	130	-	**130**
Cathodic Protection	10	10	10	**30**
Total Additions	2,876	290	10	**3,176**

18.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Part 3.3.5.1, pp. 69-70

Exhibit B-1, Part 7, Tab 7.5, Schedule 2, line 14

Exhibit B-2, FEU Workshop Presentation, p.71

FEU Amalgamated Cost of Service

*"The Companies **do not expect that there will be material cost savings** as a result of the amalgamation, since the operations and management of the utilities are already fully integrated and the savings have been captured for the benefit of customers over the 2004 through 2011 period;"* [Emphasis added]

Schedule 2, line 14 shows a reduction on Amalgamation of $5.156 million, the FEU Workshop presentation indicates a $5 million reduction on Amalgamation, and Table 3.3-10 indicates a $4.9 million reduction in the Amalgamated Cost of Service.

18.1 Please confirm the latest estimate of annual savings from the proposed Amalgamation are forecast at $5 million per year compared to 2012, and that this full amount would result in an ongoing reduction in cost to ratepayers in future years, adjusted by the one-time costs of amalgamation.

Response:

As provided on Schedule 2 of Section 7.5 (Exhibit B-1-2), the forecast change in cost of service upon amalgamation is approximately $5.156 million. The $5.156 million is compared to the summation of the stand alone cost of service for each utility in 2013 and is not compared to 2012.

Excluding any one-time costs, the ongoing amalgamated cost of service will be reduced by the forecast of $5.156 million; however, the total reduction to rates is approximately $2.2 million. Included in the total of $5.156 million is an approximate cost of service reduction of $3 million related to transportation charges paid from FEW and FEI to FEVI. These reductions to the cost of service are equally offset by reductions to revenue. That is, although the costs have decreased by $3.0 million the revenue will also decrease by $3.0 million, resulting in a net rate impact of nil. Therefore, the Other Cost of Service and Rate Base impacts of approximately $2.2 million, as identified in Table 3.3-10 and Section 7.5, Schedule 2 (Exhibit B-1-2), reflect the net impact of the cost reductions to rates.

Please note that a revised Table 3.3-10 reconciling to Section 7.5, Schedule 2 was filed with the Amendment to the Application (Exhibit B-1-2) submitted on May 16, 2011.

19.0 Reference: Revenue Requirements and Rates

Exhibit B-1, Part 3.4.2, pp. 71-73

Vancouver Island Effective Rates – RSDA

"A rate freeze for the next two year period will enable continued rate certainty for FEVI customer's until the longer term solution is in place. In the event that amalgamation is not approved, a two year rate freeze will enable natural gas on Vancouver Island to remain competitive with other energy sources for an additional 1-2 year period. To achieve this rate freeze, the RSDA mechanism must remain in place for 2012 and 2013; FEVI is seeking approval for the continuation of the RSDA. The RSDA will continue to capture the differences in 2012 and 2013 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The existing surplus balance in the RSDA will be used to partly offset the forecast revenue deficiency in 2013 and results in forecast closing RSDA balances of $53.7 million, after tax in 2012 and $42.3 million, after tax in 2013." [Ref: p. 72]

"As discussed in Part 1.2.5, using the existing low cost of gas as the base case, the future rate impacts expected for Vancouver Island are still in the range of a 20 percent increase over the next several years. This impact will be magnified, and may be doubled, should increases in the cost of gas occur. Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers." [Ref: p.73]

"FEVI is obligated under the Pacific Coast Energy Pipeline Agreement ("PCEPA") to repay a total of $75 million to the Federal and Provincial Governments that had been provided to the Company under the terms of an earlier agreement that had been entered into to support the construction of the pipeline to Vancouver Island and the Sunshine Coast. The forecasted Repayable Contributions expected to be remaining at the end of 2012 is $29.1 million and $25.0 million at the end of 2013." [Ref: p. 22]

19.1 Please provide the potential rate increases for Vancouver Island, by year, that result in the 20 percent cumulative increase. Please provide the potential rate increases for Mainland, by year, assuming no amalgamation, for the same time period.

Response:

Please refer to BCUC IRs 1.7.1 and 1.7.2.

Please note that the approximate effective burner tip rate changes provided in the table below represent a simplified forecast for 2014 through 2016 and may not reflect the actual forecast cost of service and proposed rate changes for which the Utilities will seek approval.

Approximate Burner Tip Rate Increase	2012	2013	2014	2015	2016
FEVI Annual	0.0%	8.9%	4.0%	3.9%	4.0%
FEVI Cumulative	0.0%	8.9%	12.8%	16.7%	20.7%
FEI Annual	2.4%	3.0%	2.6%	2.6%	2.7%
FEI Cumulative	2.4%	5.4%	8.0%	10.6%	13.3%

19.2 Please provide the schedule of payments for the Repayable Contributions to the Federal and Provincial governments. Please advise if there is any financial benefit, potentially through a reduction of interest cost on the Repayable Contributions, to utilize the balance in the RSDA to payout the Repayable Contribution balance sooner.

Response:

Scheduled payments for the Repayable Contributions to the Federal and Provincial governments are as follows:

2012 $20 million Federal
2013 $4.123 million Federal
2014 $10 million Provincial
2015 $10 million Provincial
2016 $5 million Provincial

The repayable contributions are non-interest bearing and are treated as a reduction in the rate base of FEVI. As such, during the time they are outstanding they benefit FEVI's customers as a source of interest-free financing. As the contributions are repaid, they will be refinanced 60 percent with debt and 40 percent with equity, resulting in both a higher rate base and increased financing costs for FEVI. Therefore, there is no benefit to repaying the contributions earlier, and in fact earlier repayment would cause an increase in the revenue deficiency and resulting decrease in the RSDA balance available to mitigate future rate pressure for customers.

20.0 Reference: Pension and Other Post Employee Benefits

Exhibit B-1, Part 3.2.2.1, p. 43

Adoption of US GAAP

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a rate base deferral account to capture any unamortized transitional benefit/obligation on the adoption of US GAAP (similar to the IFRS Transitional Deferral account). Under Canadian GAAP, these amounts are effectively part of the pension asset/liability which forms part of rate base today.

20.1 Can FEU confirm that all amounts that would be included in the proposed unamortized transitional benefit/obligation deferral account were not previously recovered in rates or forecast to be recovered in rates of the 2012-2013 RRA?

Response:

The FEU confirm that all amounts which would be included in the proposed unamortized transitional benefit/obligation deferral account were not previously recovered in rates or forecast to be recovered in rates in this Application.

In their 2010-2011 RRAs, the FEU recorded all unamortized actuarial gains and losses, unamortized past service costs and unamortized transitional obligations into the "IFRS Transitional Costs" deferral with an offset to the "Pension & OPEB Funding" deferral in anticipation of the adoption of IFRS. As the adoption of IFRS was delayed until 2012, this entry did not actually occur in 2011 and is being re-forecast to occur in 2012 in this Application. In both instances the entry was between two rate base deferral accounts and has no effect on rates. If the adoption of US GAAP for rate setting purposes on January 1, 2012 is approved, the remaining unamortized transitional obligation would be transferred to a deferral account.

21.0 Reference: Pension and OPEB Expense under US GAAP and IFRS

Exhibit B-1, Table 3.2-1, p. 44

Adoption of US GAAP

The net effect under each scenario presented above show that the effect of adopting US GAAP has a materially lower total cost compared to adopting IFRS.

21.1 If US GAAP is adopted, what impact will the adoption have on proposed rates in this Application?

<u>Response:</u>

The following table provides a summary of the approximate 2012 and 2013 total revenue requirement and rate impacts of adopting US GAAP, as discussed in the Application (Exhibit B-1), Section 3.2.2:

Approximate Impact of US GAAP Adoption	Mainland	Vancouver Island	Whistler
2012 Revenue Requirement Impact, $ Thousands	(1,489)	(47)	6
2012 Approximate Rate Impact	-0.26%	n/a	0.08%
2013 Revenue Requirement Impact, $ Thousands	(2,615)	(140)	6
2013 Approximate Rate Impact	-0.45%	n/a	0.08%

22.0 Reference: Recognition of Funded Status on the Balance Sheet

Exhibit B-1, Part 3.2.2.1, p. 45

Adoption of US GAAP

> As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a rate base deferral account to capture the difference between the carrying value otherwise determined and the funded status of the benefit plans. Similar to the transitional obligation discussed above, these amounts are effectively part of the pension asset/liability which forms part of rate base today.
>
> This is not expected to have any effect on cost of service or rate base for any of the FEU. The recognition of the funded status is simply a re-classification between the pension/OPEB rate base amounts and a deferral account.

22.1 Please confirm that the second paragraph of this excerpt indicates that there is no current or past (retroactive) impact on the cost of service or rate base for any of the FEU.

Response:

Confirmed.

22.2 Can FEU confirm that all amounts that would be included in the proposed rate based deferral account to capture differences between the carrying value otherwise determined and the funded status of the benefit plans were not previously recovered in rates or forecast to be recovered in rates of the 2012-2013 test period?

Response:

The FEU confirm that the amounts have not previously been recovered in rates.

Under IFRS, these amounts would have been included in the one-time adjustment on the adoption of IFRS. In its 2010-2011 RRA processes, the FEU had estimated a January 1, 2011 pension and OPEB transitional adjustment and included that in the Pension and OPEB Funding deferral with an equal offset to the IFRS transitional adjustment deferral, with no amortization, no recovery in rates and no net effect on rate base. In the current Application, with the change in the adoption date for IFRS, the FEU made the same estimation but as of January 1, 2012. In this Application, the FEU have amortized the IFRS Transitional Deferral Account through rates using the Expected Average Remaining Service Life ("EARSL") of employees in the pension and OPEB plans, thereby recovering a portion of the deferral account in 2012 and 2013.

If the adoption of US GAAP is approved, the one-time adjustment described above would be reversed, including the amortization of the deferral in 2012 and 2013. The funded status adjustment would become an annual adjustment but would not be amortized or recovered in rates via the amortization of a deferral but rather would be recovered in the pension expense in normal course.

23.0 Reference: Uncertain Tax Position

Exhibit B-1, Part 3.2.2.2, p. 46

Adoption of US GAAP

> As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a non rate base deferral account to capture any differences that arise from the implementation of FIN 48.

23.1 As of the date of this response, please confirm that FEU continues to believe that adoption of FIN 48 does not result in any adjustment to the 2012-2013 RRA and that no amount is anticipated to be included in the deferral account at this time.

Response:

While the FEU have not concluded their work on the transition from Canadian GAAP to US GAAP, to date, the FEU can confirm that no material amount is anticipated to be included in the non-rate base deferral account at this time. As of the date of this response, the FEU believe that the adoption of FIN 48 will not result in any adjustment to the 2012-2013 RRA.

24.0 Reference: Demand Forecast

Exhibit B-1, Part 4.4.5, Figure 4.4-9, p. 98 and Part 4.5.5, Figure 4.5-7, p. 111

Demand Forecast - Mainland

24.1 Using the format of the table below, please provide a completed breakdown of the Total Normalized Energy Demand (TJ) customer type separately for FEI and FEVI. Provide the table in fully functional electronic format. Also discuss changes in demand by customer type overtime and their impact on total demand.

Breakdown of Total Normalized Energy Demand in TJs

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential											
Commercial											
Industrial											
Transportation											
Total	184,134	180,817	176,431	172,410	176,160	170,007	165,607	168,222	168,019	168,496	168,707

Response:

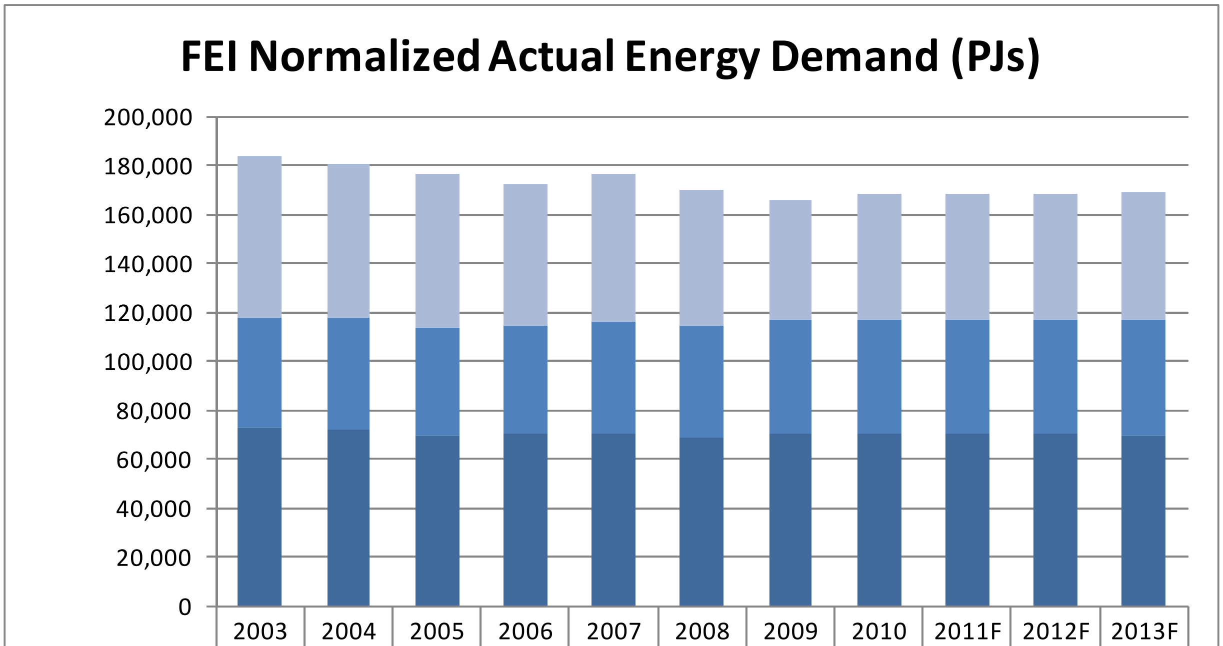
Please refer to Attachment 24.1 for the requested tables. As seen in Attachment 24.1 total consumption for FEI declined by 15.9 PJs between 2003 and 2010. The majority of this decline (14.7 PJs) was from industrial customers. Residential demand decreased by a much smaller amount while commercial demand increased slightly by 1.3 PJs. For residential demand the declining UPC has been offset by an increase of just over 69,500 net additional customers between 2003 and 2010, resulting in the more modest decrease. In 2004 the decline in total demand was largely the result of falling demand from industrial sector. However, in 2005 the impact was almost entirely the result of a decrease in Residential demand.

In 2010 Transportation consumption represented more than 60 percent of total demand for FEVI. Between 2003 and 2010 transportation customers have had the greatest impact on total demand. Residential customer demand has increased steadily since 2003, resulting in a 0.7 PJ increase in demand between 2003 and 2010.

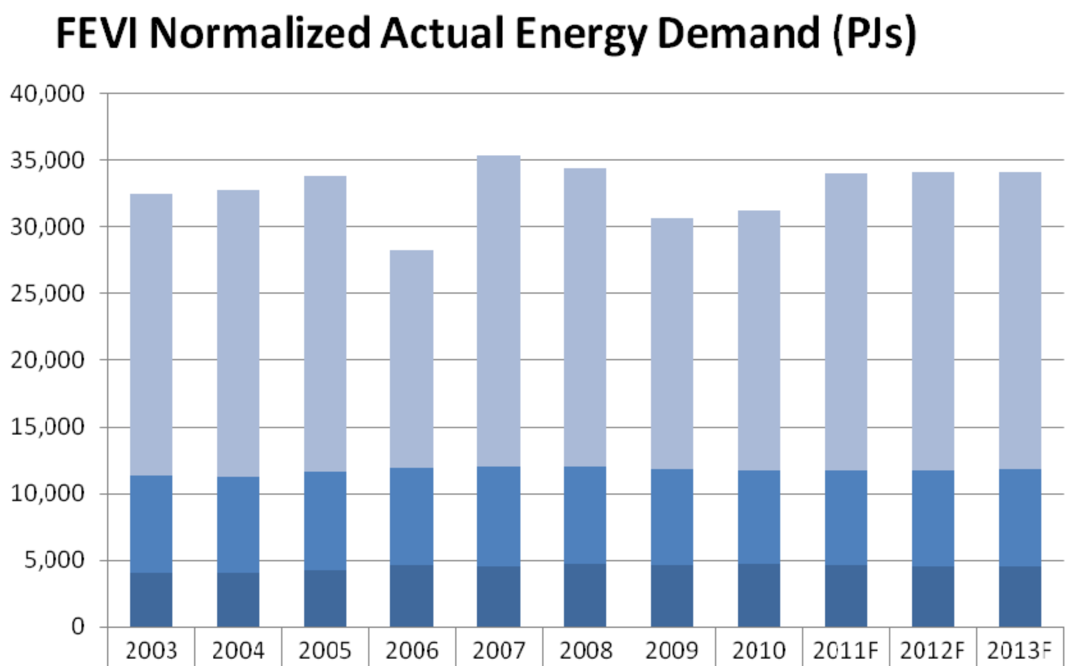
24.1.1 Using the data from the previous question, create a stacked bar graph showing the Total Normalized Energy Demand by customer type. Also provide the graph and supporting data in fully functional electronic format.

Response:

Please refer to Attachment 24.1 provided in response to BCUC IR 1.24.1, for requested graphs and supporting data in fully functional electronic format.



	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Industrial	66,220	63,564	63,251	58,318	60,014	55,291	48,424	51,538	51,226	51,547	51,559
Commercial	45,293	45,220	43,881	44,095	45,507	45,875	47,185	46,643	46,790	47,059	47,332
Residential	72,622	72,033	69,300	69,997	70,638	68,841	69,999	70,041	70,003	69,890	69,817



	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Tranportation	21,169	21,536	22,146	16,334	23,302	22,342	18,869	19,526	22,295	22,295	22,295
Commercial	7,294	7,213	7,416	7,341	7,491	7,345	7,175	7,051	7,066	7,198	7,333
Residential	4,017	4,020	4,237	4,602	4,575	4,696	4,649	4,699	4,630	4,576	4,528

25.0 Reference: Exhibit B-1, Application, Part 4.2 Overview, p. 80; Appendix C3 (spreadsheet)

Total Demand Forecast by Region

The Application states that the Companies will provide an updated forecast if there are any material changes in the forecast inputs as the regulatory process unfolds through the summer and fall of 2011.

25.1 What was the cut-off date for input data used in forecasting load for 2012 and 2013? For example, are the 2011 forecasts based on any data from the early months of 2011?

Response:

The cut-off date for input data used in forecasting load for 2012 and 2013 is December 31, 2010.

The forecast analysis for the four regions requires a significant effort to complete and was started in November of 2010. By January 2011 the Forecast system and database were being loaded with data. The forecast process was completed earlier this year so there was no opportunity to incorporate any 2011 data.

The Conference Board of Canada Single and Multiple Long Term Housing Starts report used in the account additions forecast was published on January 13, 2011. An update to this long-term forecast is expected in early 2012.

The Industrial Survey was completed in the Fall of 2010. The bulk of the responses were received in November through mid-December.

25.2 The forecast methodology for each region appears to be similar. In FEU's view, is any region more difficult to predict than others? For example, does one region have consistently large forecasting variances in UPC or customer additions?

Response:

The FEU maintain a consistent forecasting methodology across all regions. Challenges experienced for one region are often encountered in the others. In general, customer additions are found to be less predictable than use per customer (UPC).

In comparisons of the FEU's forecast results versus actuals, Whistler and Fort Nelson have shown greater UPC and customer additions variances compared to other regions. The FEU believe this is due to the small customer base. Conversely, regions with large customer bases such as Mainland and Vancouver Island tend to show smaller variances.

To overcome the forecasting variances we validate the forecast against long-term trends.

25.2.1 From the tables and charts in Appendix C3, it appears that Whistler region has small UPC forecast variances for SGS Residential and SGS Commercial but much bigger variances for LGS2 and LGS3 customer groups. Do Residential and Commercial customers in Whistler pay the same RSAM rate rider?

Response:

Confirmed. Residential and Commercial customers in Whistler pay the same RSAM rate rider because all customers in Whistler pay the same natural gas rates. The proposed RSAM rate rider per GJ for the Whistler region effective January 1, 2012, is $0.524 per GJ, which is an increase of $1.472 per GJ from the current RSAM rate rider of ($0.948). At this point in time, Whistler is not proposing any change to the RSAM rate rider effective January 1, 2013.

25.3 Based on the data showing actual and forecast UPC and customer additions provided in Appendix C3, please provide the forecast variances in tabular format. The table below is provided for illustration only.

Table – Mainland Residential (Rate 1) Forecast Variances

	Use Per Customer Variance (GJ and %)		**Customer Additions Variance (Number and %)**	
2003	4.4 GJ	4.4 %	-381	-5.7 %
2004	-2.1 GJ	-0.5 %	2716	34.0 %
2005	-6.1 GJ	-5.9 %	1775	18.4 %
2006	…..	….	-2609	-21.4 %
2007	…	…	…..	….

	Use Per Customer Variance (GJ and %)		Customer Additions Variance (Number and %)	
2008	…	….	….	…
2009	…	…	….	….
2010	2.9 GJ	3.2 %	….	….

Response:

The following tables provide the forecast variance for the major rate classes in the Mainland region. Forecast variance is calculated by subtracting actual values from forecast values provided in previous fillings. The variance is presented as a percentage of actual. Positive variance suggests forecast was higher than actual, and vice versa.

The tables below show the following:

- The UPC forecasting variance for the Mainland region ranges from -12 percent to 5 percent over the past four years. On average, the variance in residential UPC is approximately 0.6 percent, and the variance in commercial UPC is approximately -2 percent. The forecasting variance for commercial is greater than that of residential due to the volatility introduced from the smaller customer count and large range of usage patterns.
- Customer additions forecasting variance for Mainland ranges from -79 percent to 488 percent over the past four years. Compared to UPC, customer additions are much more volatile and less predictable. The great variance is attributed to factors including the recession, the timing lag between housing starts and the FEU's new customers, existing customer turnover, and also the small number of new customers in commercial Rate Schedules. On a four-year average basis, the variance on residential customer additions is approximately 20 percent, and the forecasting variance on commercial customer additions is approximately 121 percent. Similar to UPC forecast, the forecasting variance for commercial is greater than that of residential.

Mainland Residential Use Per Customer and Customer Additions Forecast Variance (Rate Schedule1)

	Use Per Customer Variance (GJ and %)		Customer Additions Variance (Number and %)	
2003	-4.4	-4.2%	381	6.0%
2004	2.1	2.0%	-2716	-25.3%
2005	6.1	6.3%	-1775	-15.5%
2006	3.8	3.9%	2609	27.2%
2007	3.8	4.0%	761	6.3%
2008	3.6	3.9%	3139	39.4%
2009	-2.2	-2.4%	3190	66.2%
2010	-2.9	-3.1%	-2047	-30.0%

Mainland Commercial Use Per Customer Forecast Variance (Rate Schedule 2)

	Use Per Customer Variance (GJ and %)	
2003	-29.8	-9.3%
2004	-13.7	-4.4%
2005	11.3	3.7%
2006	-6.7	-2.1%
2007	-2.3	-0.7%
2008	7.7	2.5%
2009	-17.6	-5.5%
2010	6.7	2.2%

Mainland Commercial Use Per Customer Forecast Variance (Rate Schedule 3)

	Use Per Customer Variance (GJ and %)	
2003	-101.5	-3.0%
2004	-158.6	-4.5%
2005	38	1.1%
2006	87.7	2.6%
2007	-32.3	-0.9%
2008	25.4	0.7%
2009	-396	-11.7%
2010	-24	-0.7%

Mainland Commercial Use Per Customer
Forecast Variance (Rate Schedule 23)

	Use Per Customer Variance (GJ and %)	
2003	-84.4	-1.7%
2004	188.2	3.7%
2005	261.3	5.5%
2006	290.7	6.2%
2007	18.4	0.4%
2008	218.3	4.6%
2009	-495	-10.1%
2010	-170	-3.5%

Mainland Commercial Customer Additions
Forecast Variance (Rate Schedule 2,3,23)

	Customer Additions Variance (Number and %)	
2003	123	-16.2%
2004	-256	-33.9%
2005	-467	-48.2%
2006	-169	-25.7%
2007	-857	-78.5%
2008	-590	-45.6%
2009	377	126.1%
2010	682	483.7%

25.3.1 Please repeat the above table for all major rate classes in the Mainland region.

Response:

Refer to the response to BCUC IR 1.25.3, where forecast variance of all major rate classes in the Mainland region is provided.

25.4 Please repeat the above table showing forecast variances for FEVI, FEW and Fort Nelson regions and all major rate classes.

Response:

The following tables provide the forecast variance for FEVI, FEW and Fort Nelson major rate classes. Forecast variance is calculated by subtracting normalized actual from the FEU's forecast provided in the previous fillings, and then the variance is presented as a percentage of actual. Positive variance suggests forecast was higher than actual, and vice versa.

FEVI

The following observations are made based on the tables below:

- The forecasting variance for UPC ranges from -28 percent to 20 percent during the previous four years. Compared to the Mainland region, the greater variance for FEVI's UPC forecast is a reflection of a smaller customer base and also lower average consumption per customer. The average variance over the previous four years is 5.1 percent for the residential Rate Schedule and -3.2 percent for commercial Rate Schedules.
- The forecasting variance for customer addition ranges from -53 percent to 46 percent during the previous four years. The average variance over the previous four years is 2.6 percent for the residential Rate Schedule and -8.2 percent for commercial Rate Schedules.

Vancouver Island Residential Use Per Customer and Customer Additions Forecast Variance (RGS)

	Use Per Customer Variance (GJ and %)		Customer Additions Variance (Number and %)	
2004	3.2	5.6%	-1489	-37.7%
2005	3.3	5.8%	290	10.7%
2006	-1.4	-2.3%	-17	-0.4%
2007	1.2	2.1%	-329	-8.8%
2008	2.2	3.9%	153	4.6%
2009	5.1	9.5%	582	20.9%
2010	2.6	5.0%	-150	-6.4%

Vancouver Island Commercial Use Per Customer
Forecast Variance (AGS)

	Use Per Customer Variance (GJ and %)	
2004	49.3	3.5%
2005	56.0	4.1%
2006	-61.8	-4.5%
2007	-41.4	-3.0%
2008	31.0	2.4%
2009	103.2	8.2%
2010	-38.8	-3.0%

Vancouver Island Commercial Use Per Customer
Forecast Variance (SCS1)

	Use Per Customer Variance (GJ and %)	
2004	12.6	19.7%
2005	-4.9	-7.0%
2006	-9.2	-12.3%
2007	-25.5	-28.1%
2008	-5.2	-5.1%
2009	-29.8	-27.0%
2010	-27.1	-26.8%

Vancouver Island Commercial Use Per Customer
Forecast Variance (SCS2)

	Use Per Customer Variance (GJ and %)	
2004	28.7	10.1%
2005	-10.9	-3.6%
2006	-19.7	-6.3%
2007	-18.5	-6.0%
2008	7.3	2.3%
2009	-12.8	-3.9%
2010	-8.2	-2.5%

Vancouver Island Commercial Use Per Customer Forecast Variance (LCS1)

	Use Per Customer Variance (GJ and %)	
2004	-9.5	-1.1%
2005	-41.3	-4.5%
2006	-5.2	-0.6%
2007	-45.1	-4.8%
2008	12.5	1.3%
2009	-49.9	-5.1%
2010	-0.1	0.0%

Vancouver Island Commercial Use Per Customer Forecast Variance (LCS2)

	Use Per Customer Variance (GJ and %)	
2004	59.2	2.6%
2005	40.3	1.7%
2006	30.9	1.3%
2007	-79.7	-3.3%
2008	2.3	0.1%
2009	-68.5	-2.8%
2010	70.6	2.8%

Vancouver Island Commercial Use Per Customer Forecast Variance (LCS3)

	Use Per Customer Variance (GJ and %)	
2004	1195.4	7.2%
2005	922.7	5.5%
2006	-733.4	-4.2%
2007	-1048.8	-5.9%
2008	141.8	0.9%
2009	1900.7	12.0%
2010	3219.8	19.7%

Vancouver Island Commercial Customer Additions
Forecast Variance (AGS, SCS1, SCS2, LCS1, LCS2)

	Customer Additions Variance (Number and %)	
2004	147	69.3%
2005	229	-164.7%
2006	-227	-80.2%
2007	-66	-53.2%
2008	-32	-15.8%
2009	-15	-10.1%
2010	38	46.3%

FEW

Whistler customers switched from propane to nature gas in 2009. The following tables show the comparison between forecast and actual for the past two years.

The UPC forecasting variance ranges from -22 percent to 34 percent. The two-year average is 0.8 percent for residential Rate Schedule and 6 percent for commercial Rate Schedule.

The forecasting variance for customer additions ranges from -57 percent to 192 percent or -66 to 23 customers. The variance is a reflection of the small number of new customers in FEW regions.

Whistler Residential Use Per Customer
Forecast Variance (SGS Residential)

	Use Per Customer Variance (GJ and %)		Customer Additions Variance (Number and %)	
2009	7.5	9.0%	-66	-56.9%
2010	-7.4	-7.4%	23	191.7%

Whistler Commercial Use Per Customer
Forecast Variance (SGS Commercial)

	Use Per Customer Variance (GJ and %)	
2009	-19.0	-7.6%
2010	-74.0	-21.9%

**Whistler Commercial Use Per Customer
Forecast Variance (LGS1)**

	Use Per Customer Variance (GJ and %)	
2009	12.7	1.1%
2010	-347.3	-21.8%

**Whistler Commercial Use Per Customer
Forecast Variance (LGS2)**

	Use Per Customer Variance (GJ and %)	
2009	828.6	33.8%
2010	294.4	10.5%

**Whistler Commercial Use Per Customer
Forecast Variance (LGS3)**

	Use Per Customer Variance (GJ and %)	
2009	2678.3	29.2%
2010	2099.8	23.7%

**Whistler Commercial Customer Additions
Forecast Variance (SCS C, LGS1,LGS2,LGS3)**

	Customer Additions Variance (Number and %)	
2009	6	85.7%
2010	1	-

Fort Nelson

The following observations are seen from Fort Nelson's forecasting variance analysis:

- The forecasting variance for UPC ranges from -7.2 percent to 81 percent over the previous four years. Compared to the other regions of the FEU, the UPC forecasting variance for Fort Nelson is a reflection of its small customer base. The forecast after 2007 shows a much smaller variance compared to the years prior to 2007.
- The average variance of the most recent three years is 1.5 percent for the residential Rate Schedule and 1.0 percent for commercial Rate Schedules.

- The forecasting variance for customer additions ranges from -6 to 22 customers or 500 percent to 314 percent during the previous four years. The variance percentage is a reflection of the small number of new customers in Fort Nelson. The average variance of the previous four years is 11 customers or -98 percent for the residential Rate Schedule and 0 customers or -77 percent for the commercial Rate Schedules.

Fort Nelson Residential Use Per Customer and Customer Additions Forecast Variance (Rate Schedule 1)

	Use Per Customer Variance (GJ and %)		Customer Additions Variance (Number and %)	
2003	-3.6	-2.2%	-74	-74.0%
2004	2.5	1.6%	-34	-65.4%
2005	11.4	7.4%	1	3.8%
2006	21.9	15.5%	33	1100.0%
2007	19.8	14.0%	22	314.3%
2008	9.2	6.6%	15	-500.0%
2009	1.9	1.4%	9	-
2010	-5.1	-3.6%	-2	-16.7%

Fort Nelson Commercial Use Per Customer Forecast Variance (Rate2.1)

	Use Per Customer Variance (GJ and %)	
2003	36.0	6.4%
2004	64.6	12.0%
2005	204.3	40.7%
2006	212.8	43.8%
2007	220.3	46.7%
2008	54.1	12.1%
2009	10.0	2.1%
2010	-33.5	-7.2%

Fort Nelson Commercial Use Per Customer
Forecast Variance (Rate Schedule 2.2)

	Use Per Customer Variance (GJ and %)	
2003	-19.0	-0.6%
2004	-414.7	-10.9%
2005	2061.5	56.7%
2006	2336.2	70.7%
2007	2499.0	81.0%
2008	174.9	5.6%
2009	-212.7	-6.3%
2010	-2.7	-0.1%

Fort Nelson Commercial Customer Additions
Forecast Variance (Rate Schedule 2.1, 2.2)

	Customer Additions Variance (Number and %)	
2003	-3	-37.5%
2004	-32	-97.0%
2005	-15	-78.9%
2006	-5	-50.0%
2007	-1	-14.3%
2008	1	25.0%
2009	5	-250.0%
2010	-6	-66.7%

26.0 Reference: Introduction

Exhibit B-1, Application, Part 1.2, pp. 82-83

EEC Programs' Impact on Mainland and Vancouver Island's UPC

The Application states that it is reasonable to assume that approved EEC funding will impact average UPC over the forecast period. In 2010 the impact was estimated to be a 0.12 GJ decline in Residential average UPC and in 2011 the impact is forecast to be a 0.16 GJ decline in Residential UPC. The Application further states that EEC savings are not a direct input into the forecast model, their effect is implicit in the generally declining UPC trends.

26.1 With the understanding that EEC savings are not a direct input into the forecast model, please clarify if the estimated decline in Residential UPC at 0.12 GJ and 0.16 GJ respectively in 2010 and 2011 is an estimate based on the EEC Residential program plans and/or evaluation. If yes, can the estimates be cross-referenced in other Parts of this Application or other regulatory filings?

Response:

Yes, FEI used the number of residential customers and divided it by the gross GJ savings from adding FEI's residential, joint initiatives, affordable housing program results/forecasts and then subtracting the fuel switching program results/forecast as listed in the table below. The numbers used to calculate the gross GJ savings can be found in Appendix K-4 of the Application (also please see Appendix B within the 2010 EEC Annual Report). This is the only part of the Application where these estimates can be cross-referenced.

The large majority of the energy savings derived from 2010 residential customer initiatives was from the 2008-2009 ENERGY STAR® Heating System Upgrade. The energy savings estimates for this program were determined from the comprehensive 2005-2007 Heating System Upgrade Program evaluation by Sampson Research, filed in response to BCUC IR 1.212.1. The other programs targeting residential customers have not been in market for a sufficient length of time to validate energy savings claims in a comprehensive analysis, as noted in the response to BCUC IR 1.212 series.

The 2011 numbers are forecasted estimates based on the program plans for the respective residential, joint initiatives, affordable housing, and fuel switching program areas.

Service Region	Residential Customers (2010)	Gross Savings-Residential and Affordable Housing (GJs)	Savings GJ/Customer
TGI[1]	760,559	108,025	0.14
TGVI[2]	90,671	(-1,952)[3]	(-0.02)
Total	851,230	106,073	0.12

Service Region	Residential Customers Forecast (2011)	Gross Savings -Residential and Affordable Housing (GJs)	Savings GJ/Customer
TGI[1]	766,724	119,998	0.16
TGVI[2]	92,999	18,352	0.2
Total	859,723	138,350	0.16

1. Rate 1 residential customers across all regions in TGI - LML,INL,COL,RSk (Not including FTN)
2. Rate 1 residential customers in TGVI
3. The negative savings is due to the result of high carbon fuel switching program

26.2 If not, why is it reasonable to assume the decline in trend is a result of EEC funding, especially if the declining trend has begun much earlier than the EEC programs?

Response:

Please refer to the response to BCUC IR 1.26.1.

27.0 Reference: Exhibit B-1, Application, Part 4.3.3, pp. 84-85

GDP Correlation to Industrial Demand

The Application states that provincial GDP is not a discrete input into the forecasting model. Figure 4.3-4 demonstrates the lack of correlation.

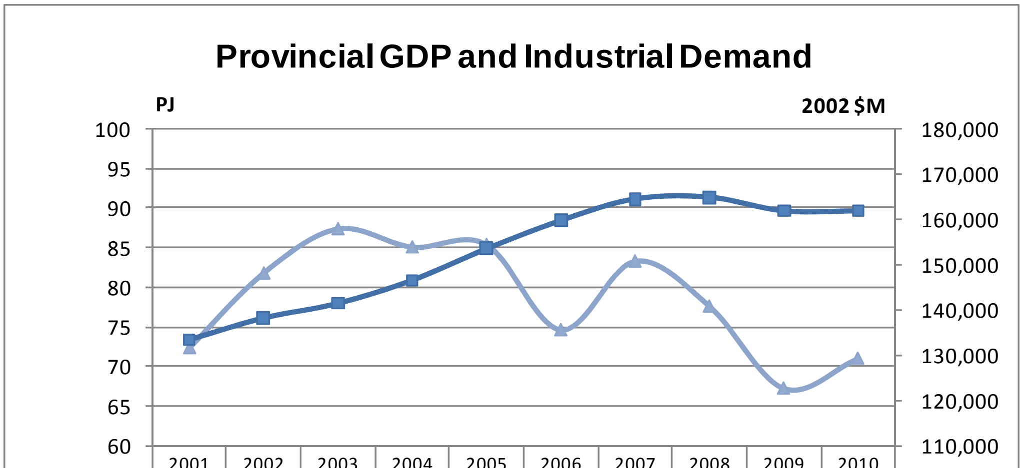
27.1 Since consumption by the Residential and Commercial sector customers could be affected by variables such as population or employment growth rather than gross output of economic products and services, please replicate Figure 4.3-4 based on these two variables: (i) provincial GDP and energy demand (PJ) from Industrial customers; and (ii) percentage change in provincial GDP and percentage change in Industrial load.

Response:

(i) GDP does not correlate to FEU's industrial demand. The analysis results in an insignificant correlation coefficient of -0.29 between provincial GDP and FEU's industrial demand. The result is attributable to multiple factors affecting natural gas consumption, and the classification of FEU's industrial customers.

Industrial rate classes include Rate Schedules 4, 5, 6, 7, 22, 25 and 27 for FEI and transportation demand for FEVI. Customers are classified based on their consumption.

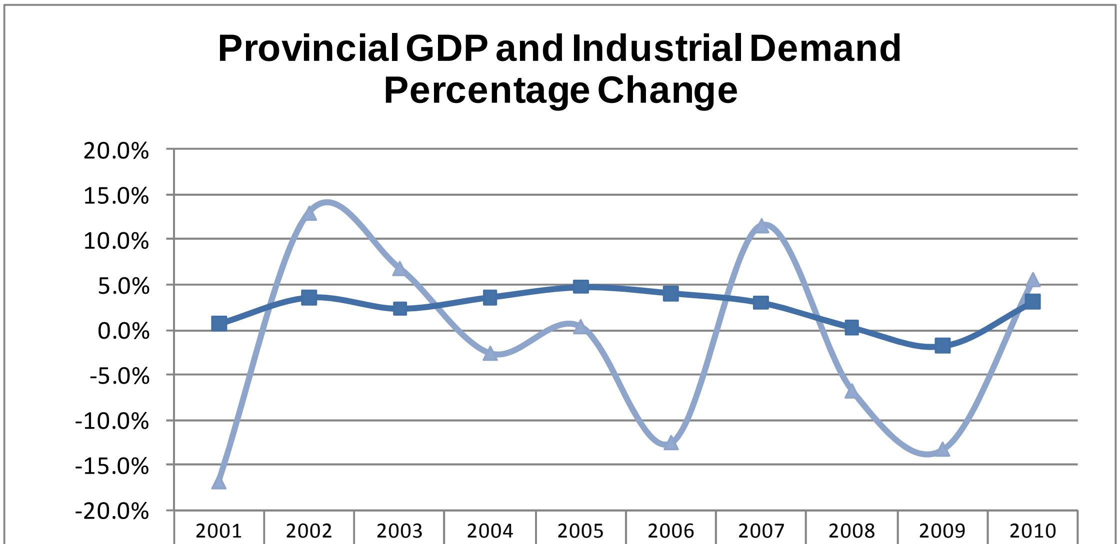
The chart below plots provincial GDP (2002 $M) and energy demand (PJ) from FEU's industrial customers.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FEU Ind	72	82	87	85	85	75	83	78	67	71
BC GDP	133,403	138,193	141,435	146,541	153,489	159,729	164,496	164,869	161,851	161,850

(ii) No relationship is found between GDP growth and percentage of FEU's industrial demand. The analysis shows an insignificant correlation coefficient of 0.52 between the two variables. Further analysis is similar to the discussion in part (i) above.

The chart below plots percentage change in provincial GDP and percentage change in FEU Industrial load.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FEU Ind	-17.0%	13.0%	6.8%	-2.6%	0.3%	-12.6%	11.6%	-6.8%	-13.3%	5.6%
BC GDP	0.6%	3.6%	2.3%	3.6%	4.7%	4.1%	3.0%	0.2%	-1.8%	3.1%

27.2 Please comment on the degree of statistical correlation between Industrial load with GDP.

Response:

The correlation between the FEU's industrial load and provincial GDP is -0.29, calculated based on the data in the following table. At this time, the FEU is not able to identify any relationship between provincial GDP and the industrial demand.

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Provincial GDP (2002 $M)	133,403	138,193	141,435	146,541	153,489	159,729	164,496	164,869	161,851	161,850
FEU Industrial Load (PJ)	72	82	87	85	85	75	83	78	67	71

Since provincial GDP does not correlate with the FEU's industrial load, it is not a discrete input into the forecasting model. The forecast of industrial demand is based upon an industrial survey that is consistent with the methodology used in prior years.

28.0 Reference: Exhibit B-1, Application, Part 4.3.5, p. 87

Weather vs. Customer Additions as Demand Drivers

The Application states that on average total residential demand is more than five times more sensitive to weather fluctuations than it is to the demand from new customers. This statement was supported by an analysis of comparing the variances from (a) actual and normalized difference in absolute values, and (b) demand from Lower Mainland new customers.

28.1 Since the current practice is to use 10 years of data for normalization, please provide a 10-year average in Table 4.3-1.

Response:

Once 2001 and 2002 are included in the supporting calculations for Table 4.3-1 the average weather attributable demand variance changes from 3.2 PJ/yr to 2.8 PJ/yr.

Table 4.3-1 with 2001 and 2002 added is shown below.

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	10-Yr Avg
Actual Demand (PJ)	50.9	56.2	50.7	48.4	51.1	51.3	56.2	58.8	53.2	48.7	52.3
Normalized Demand (PJ)	49.9	54.2	54.0	53.9	51.6	52.1	52.7	51.6	52.4	52.6	52.6
Difference (PJ)	1.0	2.0	-3.3	-5.5	-0.5	-0.8	3.5	7.2	0.8	-3.9	
Absolute value of Difference (PJ)	1.0	2.0	3.3	5.5	0.5	0.8	3.5	7.2	0.8	3.9	2.8

29.0 Reference: Exhibit B-1, p. 89 and Appendix C-3

Industrial Demand Forecast

29.1 Does the Industrial Demand Survey contain a request of customers to provide a multi-year forecast of annual demand?

Response:

Yes, the current Industrial Survey does contain a section where the customer is asked to provide a multi-year forecast of annual demand. For the 2010 Industrial Survey, customers were asked to provide annual estimates for 2012 through 2015.

A sample survey (with customer details deleted) is shown below.

Terasen Gas 2010 Industrial Demand Survey

Service Address:
Company Name
Address
City

Account: acct number
Premise: number
Rate Class: rate class

Instructions:
1) Please update all the BLUE cells...
2) Review and update the monthly demand for the remainder of 2010 and 2011.
3) Update the annual demand for 2012 through 2015.
4) Email or print and FAX the completed survey back to us.

Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2007	30,302	28,517	31,554	30,366	23,425	23,249	31,502	26,136	28,488	29,646	33,381	23,857	340,423
2008	37,961	30,881	30,944	20,070	32,017	28,296	35,027	29,024	25,047	29,693	28,762	30,946	358,668
2009	27,465	27,231	31,156	27,432	26,480	25,300	27,005	21,755	16,885	23,583	21,762	22,429	298,483
2010	26,785	24,869	16,890	25,940	22,830	21,809	18,353	17,397	17,525	20,481	19,500	21,500	253,879
2011	23,600	22,800	26,000	27,400	29,500	30,700	29,100	28,900	26,700	24,500	27,400	26,100	322,700

Year	2012	2013	2014	2015
Annual Demand	340000	330000	345000	350000

Name: Name
Email Address: Email back to industrial.survey@terasengas.com OR
Phone: phone
Date: 12/6/2010

Terasen Gas has a number of Energy Efficiency and Conservation programs available to our commercial and industrial customers. May we contact you to discuss our rebate programs?

☐ Yes, please contact me (enter an 'x')
☐ No thanks

Please complete this form and DO ONE OF THE FOLLOWING:

☐ Email back to **industrial.survey@terasengas.com OR**
☐ Print and FAX to Commercial & Industrial Energy Solutions (604) 592-7894

- Cells coloured orange (January 2007 through August 2010) are actual values and are shown on the survey form to assist the customer.

- Cells coloured blue are empty when sent to the customer, and are the cells the customer fills in.
- Cells coloured green are calculated (the sum of the 2010 and 2011 monthly estimates).

Based on the historic consumption pattern the annual values (2012 through 2015) are distributed to monthly values and saved to the Forecasting System database. All monthly and annual forecast values are saved.

A unique Industrial Survey file (Microsoft Excel format) is generated for each customer. Currently the file is sent to each customer via email.

Appendix C3 contains live spread sheets containing a comparison of the actual and forecast industrial demand for the period 2004 to 2013.

29.2 Please provide a comparison of the actual and forecast industrial demand for the period 2004 to 2013 for each of the following sectors: pulp & paper, wood products, greenhouses, mining, apartments and condominiums, chemical manufacturing, food and beverage, and other.

Response:

Subsequent to the 2010-2011 RRA and 2010 LTRP applications, the FEU completed some analysis of our industry classification data. Through this analysis we determined that our industry classification data is not reliable enough to be used for a sector analysis of actual data. While we are still able to perform a sector analysis of actuals, the results would be too unreliable to be used to make meaningful comparisons between forecast and actual values.

Internal projects in the past have attempted to update and maintain our North American Industry Classification System ("NAICS") data but have proven to be very difficult to complete at the high level of accuracy needed for this analysis. Many industrial customers are reluctant to participate in such surveys and trying to determine the NAICS classification of a debtor based on name or other identifying attribute is error prone.

Additionally, the Forecasting Information System ("FIS") does not maintain industrial classification information in its database. In order to complete a comparison of forecast to actuals by sector, industrial classification capabilities would need to be added to FIS and then this data would need to be collected and entered for the annual forecasts back to 2004.

To improve this situation we have started a Survey Improvement Project to further enhance our industrial survey. The project is in the design stages but will likely include the ability to reach a much larger group of customers (including large commercial customers). In addition we will track the respondents' performance and give them an opportunity to maintain their industry classification.

29.3 To what extent do revenues from industrial customers vary with consumption? In other words, what percentage of industrial margins is fixed?

Response:

Industrial Revenues are comprised of both fixed and variable charges, and the portion each contributes to revenue varies by Rate Class and use rate. Table 1 below shows the approximate Revenue split between Fixed and Variable portions for FEU Industrial Rate Class customers at the current 2012 RRA volumes and use rates.

Table 1

Total 2012 Revenue split between Fixed and Variable portions using 2012 Use Rate Assumptions

Line No.	Particulars	Fixed Percent	Variable Percent	Fixed Revenue (000)	Variable Revenue (000)	Total Revenue (000)	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**FEI**						
2	Rate 4	7%	93%	$ 87	$ 1,176	$ 1,263	- Sect 7-TAB 7.1, Schedule 11
3	Rate 5	26%	74%	4,853	14,068	18,921	- Sect 7-TAB 7.1, Schedule 11
4	Rate 6	3%	97%	15	485	500	- Sect 7-TAB 7.1, Schedule 11
5	Rate 7	38%	62%	42	70	112	- Sect 7-TAB 7.1, Schedule 11
6	Rate 22	11%	89%	2,174	17,680	19,854	- Sect 7-TAB 7.1, Schedule 11 (lines 18 + 19)
7	Byron Creek	92%	8%	50	5	55	- Sect 7-TAB 7.1, Schedule 11
8	Burrard Thermal	100%	0%	9,983	13	9,996	- Sect 7-TAB 7.1, Schedule 11
9	FEVI Wheeling[1]	100%	0%	-	-	-	- Sect 7-TAB 7.1, Schedule 11
10	Rate 25	66%	34%	16,729	8,650	25,379	- Sect 7-TAB 7.1, Schedule 11
11	Rate 27	15%	85%	1,076	6,306	7,382	- Sect 7-TAB 7.1, Schedule 11
12							
13	**FEVI**						
14	BCH	100%	0%	14,903	-	14,903	- Sect 7-TAB 7.2, Schedule 11
15	VIGJV	100%	0%	2,832	-	2,832	- Sect 7-TAB 7.2, Schedule 11
16	FEW Wheeling[2]	100%	0%	2,585	-	2,585	- Sect 7-TAB 7.2, Schedule 11
17	Squamish Wheeling[3]	100%	0%	414	-	414	- Sect 7-TAB 7.2, Schedule 11
18							
19	**FEFN**						
20	Rate 25	12%	88%	17	124	141	- Sect 7-TAB 7.4, Schedule 11

Notes

1: Wheeling agreement between FEI and FEVI where FEVI pays FEI for the use of FEI's pipeline to deliver Natural Gas to Vancouver Island

2: Wheeling agreement between FEVI and FEW where FEW pays FEVI for the use of FEVI's pipeline to deliver Natural Gas to Whistler

3: Wheeling agreement between FEVI and FEI where FEI pays FEVI for the use of FEVI's pipeline to deliver Natural Gas to Squamish

The approximate fixed and variable portions of revenue within Table 1 are calculated using 2012 forecasted volumes at existing rates. The fixed portion of revenue typically includes basic charges, admin charges and contract demand. The variable portion of revenue typically includes commodity and midstream charges for non-transportation customers plus delivery charges.

All else being equal, the fixed and variable portions of revenue are affected by changes in use-rate. If a rate class' use-rate changes year over year, then the variable and fixed portions of their revenues will change as well, see Table 2 for a basic example.

Table 2

FEI Rate 7 Basic Example

Line No.	**Particulars**	**Revenue Type**	**Original Assumptions**	**Use Rate Increase**	**Change**	**Calculation**
	(1)	(2)	(3)	(4)	(5)	(6)
1	Accounts		1	1	-	
2	Use Rate (GJ/yr)		2,700	***3,000***	300	
3	Basic Charge ($/Month)	Fixed	$ 880	$ 880	-	
4	Delivery Charge ($/GJ)	Variable	$ 1.073	$ 1.073	-	
5	Commodity Charge ($/GJ)	Variable	$ 5.370	$ 5.370	-	
6	Months		12	12	-	
7						
8	Annual Charges					
9	Fixed		$ 10,560	$ 10,560	$ -	= Line 1 * Line 3 * Line 6
10	Variable		$ 17,396	$ 19,329	$ 1,933	= Line 1 * Line 2 * (Line 4 + Line 5)
11	Total Charges		$ 27,956	$ 29,889	$ 1,933	= Line 9 + Line 10
12						
13	Fixed		37.8%	35.3%	-2.4%	= Line 9 / Line 11
14	Variable		62.2%	64.7%	2.4%	= Line 10 / Line 11

29.4 Please confirm whether or not FEU continues its past practice of excluding deliveries to Burrard Thermal from the industrial demand forecast.

Response:

Consistent with past filings, the FEU have not included Burrard Thermal demand in the Industrial Forecast.

Burrard Thermal is purely a transportation contract customer and the 2012-2013 contract remains at 275 TJ/day. Revenues received under this contract are fixed regardless of the amount of natural gas consumed by Burrard Thermal.

29.5 Please provide any forecasts and adjustments to the projected natural gas demand for Burrard Thermal over the Forecast Period 2012 and 2013.

Response:

Currently there are no forecasts or adjustments planned for Burrard Thermal for the forecast period 2012 and 2013. The FEU have a fixed contact agreement with Burrard Thermal of 275 TJs per day through 2012 and 2013. No change is anticipated to this contract which does not expire until November 1, 2029.

30.0 Reference: Exhibit B-1, Application, Part 4.4.3, pp. 83, 93

Mainland – Residential and Commercial Use Rates

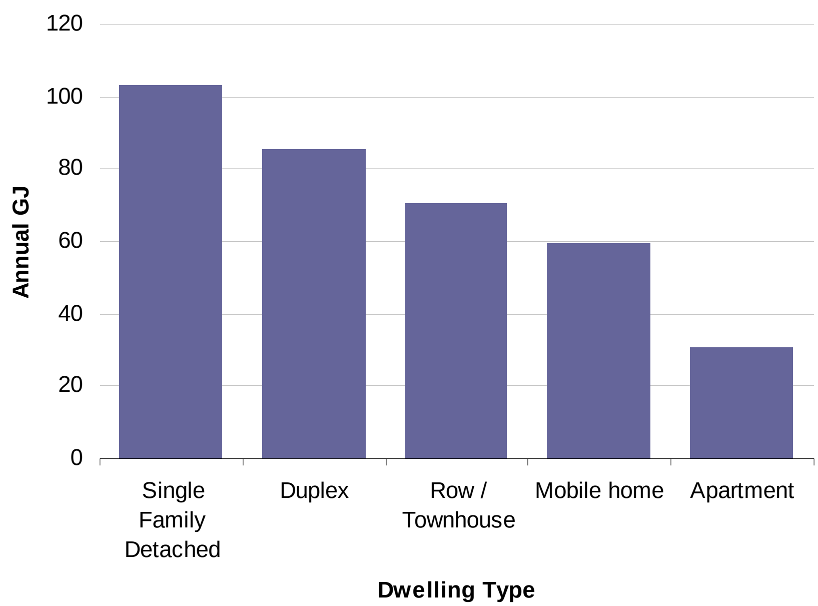
The Application states that the Residential UPC is forecast to continue downward at approximately 0.9 GJ per year for the Mainland region.

30.1 In FEI's view, does changing mix of housing stock exacerbate its decline?

<u>Response:</u>

In FEI's view, the changing mix of housing stock is one of many factors that could contribute to the decline in UPC for the Mainland region. As seen in the graph below, average annual consumption or UPC varies by dwelling type.

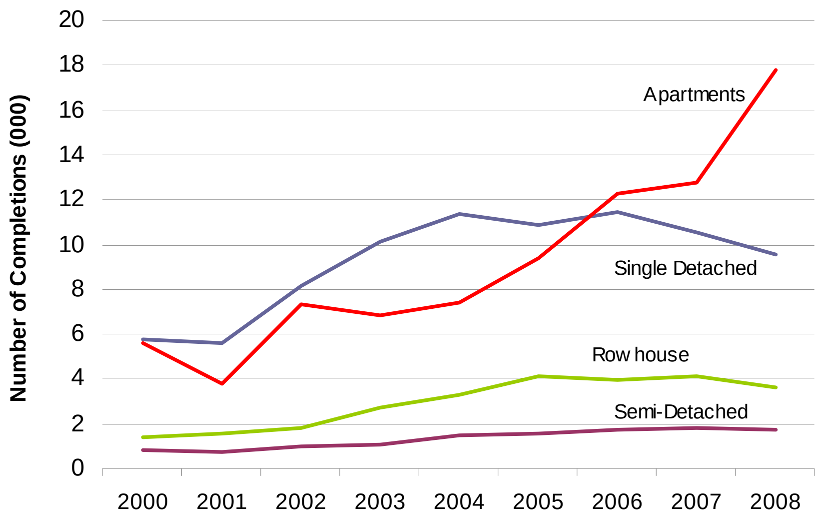
Average Annual Consumption (GJ) by Dwelling Type



Data Source: 2008 Residential End Use Study

Further, a trend shifting new construction towards Multi-Family Dwellings (MFDs) has been occurring in BC (see graph below).

Housing Completions – Urban BC



Data source: CMHC

Holding the current new housing mix ratio constant, the changing mix in housing stock would result in a lower UPC in the long-run. However, as noted in the 2008 Residential End Use study conducted by Sampson Research, "Since newly built dwellings represent only a 1% to 2% increase in total stock of housing in British Columbia in a given year, new construction trends influence the relative composition of the stock of housing relatively slowly over the long-run."

30.2 FEI has developed separate single and multi family dwelling forecasts for Residential customer additions. To what extent could such data intended to improve forecast of customer additions also assist in the forecast of use rates?

<u>Response:</u>

The data used to develop separate single-family dwelling ("SFD") and multi-family dwelling ("MFD") forecasts for residential customer additions could not be used to improve the forecast of use rates. FEI is able to forecast housing starts by type because the Conference Board of Canada ("CBOC") provides the housing type split in their housing starts forecast. However, FEI's internal billing systems do not capture housing type information and therefore a UPC trend by housing type cannot be developed. As use rates are forecast by analyzing historic actual billing data and our billing system does not capture housing type, FEI cannot currently develop separate single and multi-family dwelling use rate forecasts.

Without historical UPC data by housing type, the FEU would need to derive the SFD and MFD UPC values using a different methodology, inconsistent with past practice. This is not something the FEU are doing now but may consider in the future if there is a significant shift in housing type over time. A future change could also be implemented through different rate classes within Rate Schedule 1 to separately capture data for single and multi-family dwellings.

31.0 Reference: Exhibit B-1, Application, Part 4.4.2 p. 92 & Part 6.4.1 p. 387

Revenue Stabilization Adjustment Mechanism

The RSAM stabilizes delivery margin from Residential and Commercial customers on a UPC basis. Figure 4.4-1 shows the RSAM volume (TJs) from 2003-2010. The Application describes negative volumes are indication of below normal temperatures.

31.1 Is it always true that negative RSAM volumes are indication of below normal temperatures and positive RSAM volumes are indication of above normal temperatures? Is it also true that RSAM balance implicitly includes variations due to factors such as economic activity level or customer behaviour due to commodity price fluctuations, etc?

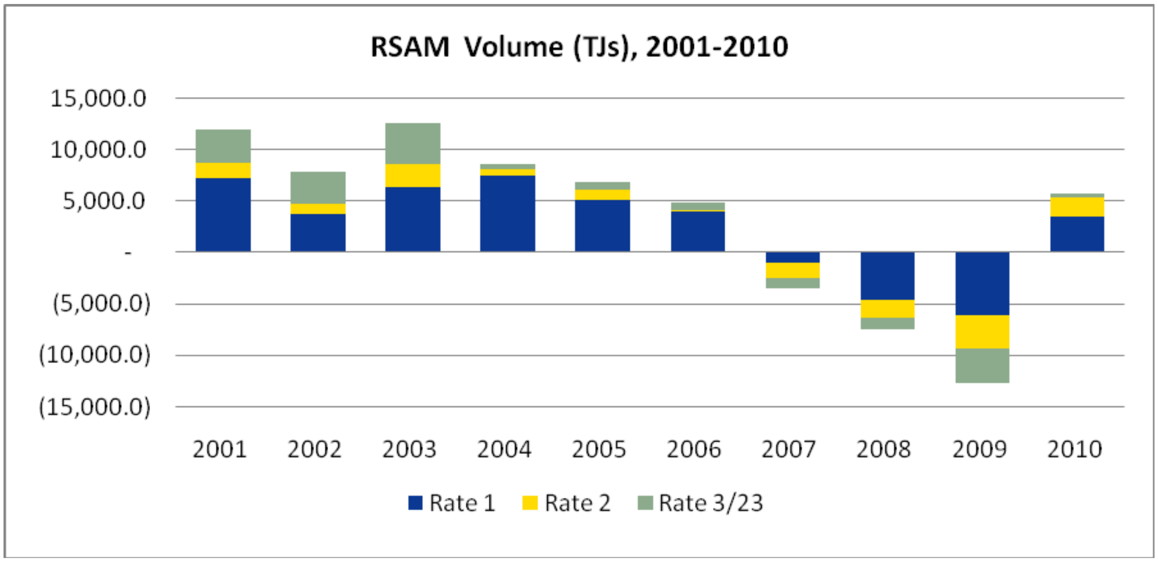
Response:

It is generally true that, as portrayed in Figure 4.4-1, negative RSAM volumes are an indication of below normal temperatures and positive RSAM volumes are an indication of above normal temperatures. However, as indicated in Section 6.3.1.3 of the Application (page 388, Exhibit B-1), the RSAM captures variations in customer use rates from forecast due to "weather or other factors." Thus, the RSAM mitigates the effects of unpredictable and uncontrollable factors, namely volume volatility caused primarily by weather and natural gas cost volatility, but will also include other factors contributing to a variance in the customer use rates from forecast.

31.1.1 Please extend Figure 4.4-1 back to 2001 from 2003 and provide the underlying numbers to the chart.

Response:

Please see the tables below.



	Rate 1	Rate 2	Rate 3/23	Total
2001	7,242.2	1,471.2	3,282.4	11,995.7
2002	3,663.1	1,058.8	3,070.6	7,792.5
2003	6,338.5	2,268.1	3,942.0	12,548.6
2004	7,404.3	668.3	511.4	8,584.0
2005	5,075.2	1,062.2	641.5	6,778.9
2006	4,033.6	8.3	858.4	4,900.3
2007	(1,030.3)	(1,436.9)	(1,027.1)	(3,494.3)
2008	(4,654.7)	(1,711.7)	(1,116.4)	(7,482.8)
2009	(6,099.9)	(3,202.2)	(3,390.2)	(12,692.3)
2010	3,508.6	1,834.1	374.6	5,717.3
	25,480.5	2,020.3	7,147.2	34,648.0

31.2 Please provide similar tables and charts related to the RSDA in Part 4.5.2, and RSAM in Parts 4.6.2 and 4.7.2.

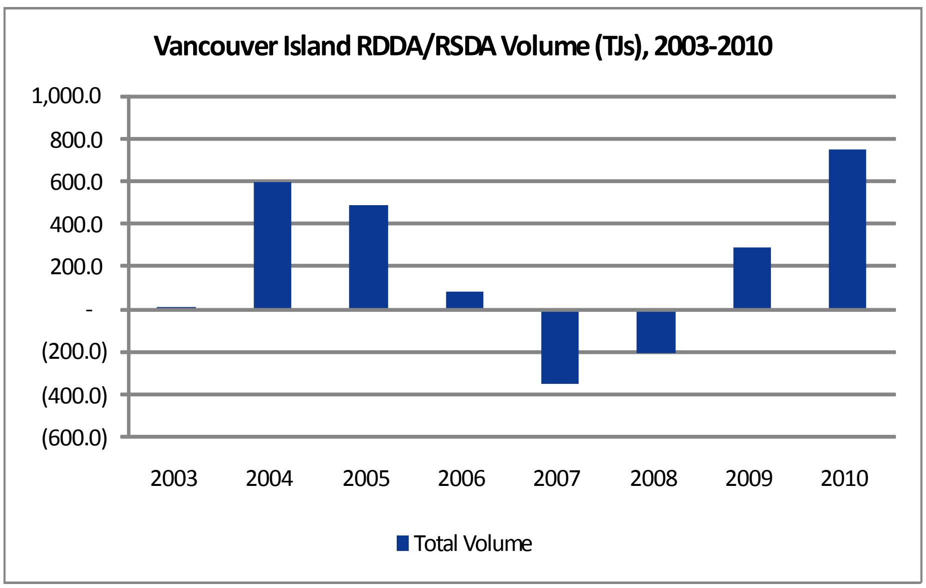
Response:

Please see the tables and charts below for Vancouver Island, Whistler and Fort Nelson.

Vancouver Island

Unlike RSAM, there is not a direct link between the RDDA/RSDA additions and the volume variance in FEVI. This is because the RDDA/RSDA captures variances related to the overall cost of service (excluding O&M variances) and revenues in FEVI, whereas the RSAM only captures variances in customer use rates which are a volumetric measure.

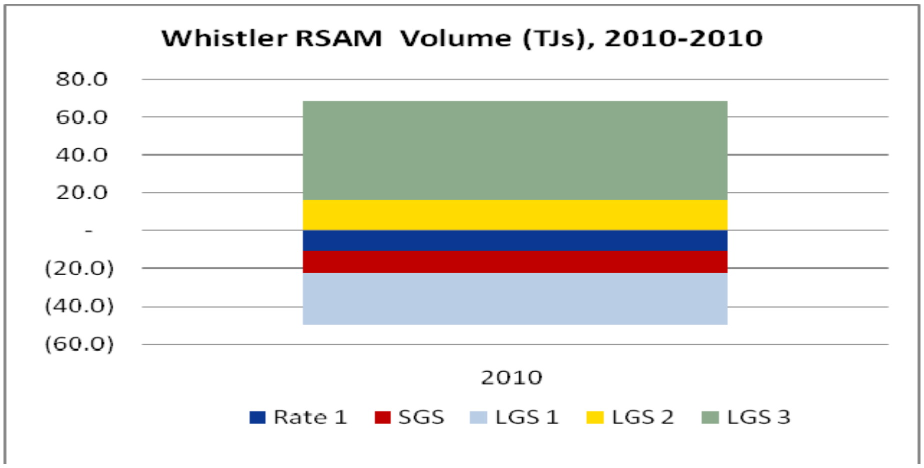
	Total Volume
2003	394.0
2004	596,312.0
2005	492,145.0
2006	82,493.0
2007	(351,458.0)
2008	(205,383.0)
2009	289,732.0
2010	749,771.0
	1,654,006.0



Whistler

Only one year of history pertaining to the RSAM deferral account exists for Whistler. As discussed in Section 6.3.1.3 of the Application, and as approved by Commission Order No. G-138-10, Whistler discontinued the use of the Sales Margin Differential account and adopted the RSAM deferral account in 2010.

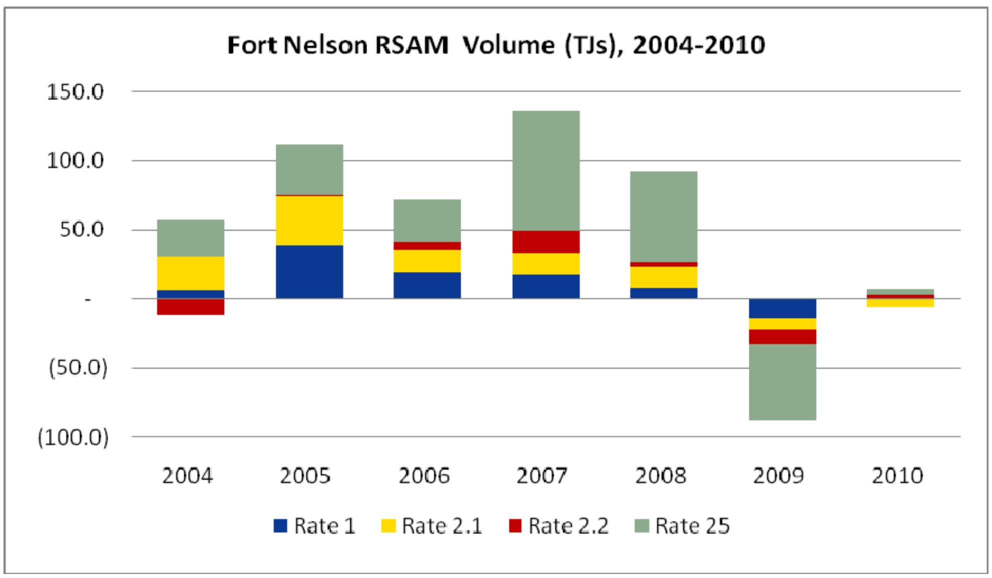
	Rate 1	SGS	LGS 1	LGS 2	LGS 3	Total
2010	(10.8)	(11.5)	(27.6)	16.2	52.3	18.6
	(10.8)	(11.5)	(27.6)	16.2	52.3	18.6



Fort Nelson

The use of the RSAM account was first approved in Fort Nelson in 2004; therefore, 2003 is not applicable.

	Rate 1	Rate 2.1	Rate 2.2	Rate 25	Total
2004	6.3	24.8	(11.2)	25.6	45.5
2005	38.7	35.8	1.0	35.9	111.4
2006	19.1	16.2	5.9	31.3	72.5
2007	17.5	15.6	16.6	86.2	135.9
2008	7.9	15.5	3.5	65.4	92.4
2009	(13.9)	(7.8)	(10.9)	(55.4)	(88.1)
2010	(0.0)	(6.4)	3.2	4.6	1.3
	75.6	93.8	8.1	193.5	370.9



31.3 Please demonstrate how the RSAM balances ($ thousands) shown in Table 6.3-3 are derived from the above RSAM volumes.

Response:

The annual RSAM volumes provided in Figure 4.4-1 were used to determine the RSAM additions for each of the respective years. As the RSAM additions are recovered through a

Commission Approved Rider over three years, only the 2009 and 2010 RSAM additions would have a residual rider recovery impact on the 2012 and 2013 ending balances of Schedules 68 and 70 in Section 7 of the Application (Exhibit B-1), Tabs 7.1, 7.3, and 7.4 and the mid-year account balances in Table 6.3-3.

The closing balance in the RSAM account is determined as the opening balance, plus the additions for the year and is offset by the recovery or refund of the account through the Commission Approved Rider applicable for that year. The RSAM volumes are the basis for the additions to the account, calculated as follows:

- The RSAM volume for each month (for each rate schedule, within each division in the case of FEI) is the use rate variance (forecast – actual) multiplied by the actual number of customers for that month;
- The RSAM volume is multiplied by the approved delivery rate to determine the RSAM addition for that month; and
- This same calculation is done for each month and then summed together to form the RSAM addition for the year.

RSAM account balances are recovered from or returned to customers over a three-year period. Therefore, all else equal the RSAM additions in 2010, will be fully amortized by the end of 2013.

The following tables provide the derivation of the mid-year account balances included in Table 6.3-3:

Mainland RSAM	2012 ($thousands)	2013 ($thousands)	Reference
Opening Balance	$ (8,325)	$ (5,550)	Tab 7.1, Schedule 68, 70
Additions	$ -	$ -	Tab 7.1, Schedule 68, 70
Rider	$ 3,700	$ 3,700	Tab 7.1, Schedule 68, 70, 85
Tax on Rider	$ (925)	$ (925)	Tab 7.1, Schedule 68, 70, 85
Ending Balance	$ (5,550)	$ (2,775)	Tab 7.1, Schedule 68, 70
Mid-Year	**$ (6,937)**	**$ (4,162)**	Table 6.3-3

Whistler RSAM	2012 ($thousands)	2013 ($thousands)	Reference
Opening Balance (includes adjustment)	$ 843	$ 562	Tab 7.3, Schedule 68, 70, Pg. 388 6.3.1.3
Additions	$ -	$ -	Tab 7.3, Schedule 68, 70
Rider	$ (375)	$ (375)	Tab 7.3, Schedule 68, 70, 85
Tax on Rider	$ 94	$ 94	Tab 7.3, Schedule 68, 70, 85
Ending Balance	$ 562	$ 281	Tab 7.3, Schedule 68, 70
Mid-Year	**$ 703**	**$ 422**	Table 6.3-3

Fort Nelson RSAM	2012 ($thousands)	2013 ($thousands)	Reference
Opening Balance	$ (19)	$ (12)	Tab 7.4, Schedule 68, 70
Additions	$ -	$ -	Tab 7.4, Schedule 68, 70
Rider	$ 8	$ 8	Tab 7.4, Schedule 68, 70, 85
Tax on Rider	$ (2)	$ (2)	Tab 7.4, Schedule 68, 70, 85
Ending Balance (rounding)	$ (12)	$ (6)	Tab 7.4, Schedule 68, 70
Mid-Year	**$ (16)**	**$ (9)**	Table 6.3-3

32.0 Reference: Exhibit B-1, Application, Part 4.4.5, p.101

Mainland – Industrial Demand

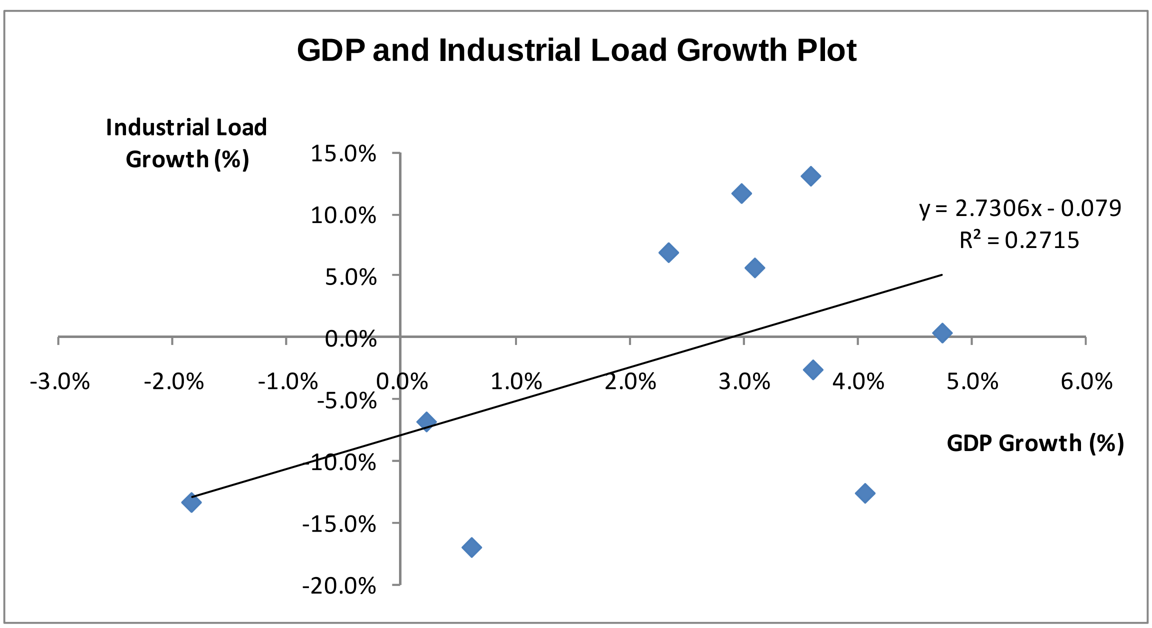
A part of the methodology for forecasting Industrial Demand, the demand for Industrial customers that did not participate in the annual survey was held constant at 2010 levels.

32.1 What would have been the impact on total Industrial demand (TJ) if, for those Industrial customers who did not participate in the annual survey, FEI increased for each customer its load by the forecasted annual GDP growth rates in 2012 and 2013, or by some established statistical correlation between industrial load and GDP?

Response:

If GDP were applied to the 17 percent (Figure 4.3-6, Exhibit B-1)) of the FEU's industrial load using the regression line equation shown in the graph, the impact would be an increase of approximately 0.2 PJs or 0.3 percent of the annual industrial load per year. Please be advised that due to the low R^2, the outcome predicted by the model is unlikely to be reliable.

The FEU have conducted an analysis to establish the relationship between the growth of historic GDP and industrial demand based on 10 years of data. The analysis shows a 0.52 correlation between the two variables. The following graph plots the growth of BC GDP and FEU's industrial load.



	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	(0.079)	0.048	(1.639)	0.140
X Variable 1	2.731	1.582	1.726	0.123

The regression analysis shows a low R-square and insignificant p-values for model coefficients, which could be a result of:

- lack of relationship between GDP and industrial consumption; and
- heat-sensitive portion of Industrial load.

The Companies believe that last year's consumption is the best estimate of short-term forecast for customers who did not respond to the annual survey.

33.0 Reference: Capital Expenditures

Exhibit B-1, Part 4.4.4, pp. 96-97, 109-110, 120-124 and 129-130; Appendix D-6

Capital Expenditures by Type net of Contributions in Aid of Construction

33.1 Using the format of the table below, please prepare Capital Expenditure Metrics schedules for 2006-2013 for FEI, FEVI, FEW and Fort Nelson. Also provide the tables in fully functional electronic format.

Capital Expenditure Metrics per Customer

	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance	Forecast 2012	Forecast 2013
Sustainment Capital /Total Average Customers								
Growth Capital/Customer Additions								
Other Capital/Total Average Customers								

Response:

Capital Expenditure Metrics schedules for 2006-2013 for FEI, FEVI, FEW and Fort Nelson are provided in the tables below.

Capital Expenditure Metrics 2006-2013 – Mainland

Metric	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance
Sustainment Capital / Total Average Customers	N/A	53	N/A	N/A	43	N/A	N/A	51	N/A	N/A	57	N/A
Growth Capital / Gross Customer Additions	N/A	2,151	N/A	N/A	1,867	N/A	N/A	2,220	N/A	N/A	2,013	N/A
Other Capital / Total Average Customers	N/A	16	N/A	N/A	12	N/A	N/A	19	N/A	N/A	28	N/A

Metric	2010 Approved	2010 Actual	2010 Variance	2011 Forecast	2012 Forecast	2013 Forecast
Sustainment Capital / Total Average Customers	54	54	0	55	77	87
Growth Capital / Gross Customer Additions	2,620	2,119	501	2,538	2,550	2,602
Other Capital / Total Average Customers	27	24	3	27	35	29

Note: As Mainland 2006-2009 capital expenditures were based on formula as per the PBR agreement; no approved capital by the Metrics listed is available.

Capital Expenditure Metrics 2006-2013 – Vancouver Island

Metric	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance
Sustainment Capital/ Total Average Customers	139	88	51	163	138	25	97	96	1	99	91	8
Growth Capital/Gross Customer Additions	2,102	2,177	(74)	2,232	2,803	(571)	3,746	3,644	103	3,960	2,817	1,143
Other Capital/Total Average Customers	12	40	(28)	27	16	12	24	21	3	36	40	(3)

Metric	2010 Approved	2010 Actual	2010 Variance	2011 Forecast	2012 Forecast	2013 Forecast
Sustainment Capital/ Total Average Customers	92	72	20	125	157	133
Growth Capital/Gross Customer Additions	3,806	3,131	674	2,920	3,006	3,084
Other Capital/Total Average Customers	34	31	4	32	53	58

Capital Expenditure Metrics 2006-2013 – Whistler

Metric	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance
Sustainment Capital/ Total Average Customers	N/A	23	N/A	N/A	18	N/A	N/A	56	N/A	117	133	(16)
Growth Capital/Gross Customer Additions	N/A	2,927	N/A	N/A	10,295	N/A	N/A	17,005	N/A	3,580	3,509	71
Other Capital/Total Average Customers	N/A	0	N/A	N/A	1	N/A	N/A	24	N/A	89	24	65

Note: No approved capital expenditure metrics are available for 2006-2008 as FEW did not apply for rates for these years.

Metric	2010 Approved	2010 Actual	2010 Variance	2011 Forecast	2012 Forecast	2013 Forecast
Sustainment Capital/ Total Average Customers	46	45	1	52	49	47
Growth Capital/Gross Customer Additions	4,786	10,113	(5,328)	15,011	14,690	15,013
Other Capital/Total Average Customers	27	8	20	16	119	28

Capital Expenditure Metrics 2006-2013 – Fort Nelson

Metric	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance
Sustainment Capital/ Total Average Customers	N/A	159	N/A	N/A	17	N/A	13	27	(14)	57	104	(48)
Growth Capital/Gross Customer Additions	N/A	607	N/A	N/A	977	N/A	1,398	1,478	(80)	3,432	3,052	381
Other Capital/Total Average Customers	N/A	0	N/A	N/A	1	N/A	7	0	7	3	14	(11)

Metric	2010 Approved	2010 Actual	2010 Variance	2011 Forecast	2012 Forecast	2013 Forecast
Sustainment Capital/ Total Average Customers	N/A	146	N/A	1,142	168	80
Growth Capital/Gross Customer Additions	N/A	3,421	N/A	1,766	1,833	1,837
Other Capital/Total Average Customers	N/A	0	N/A	3	58	4

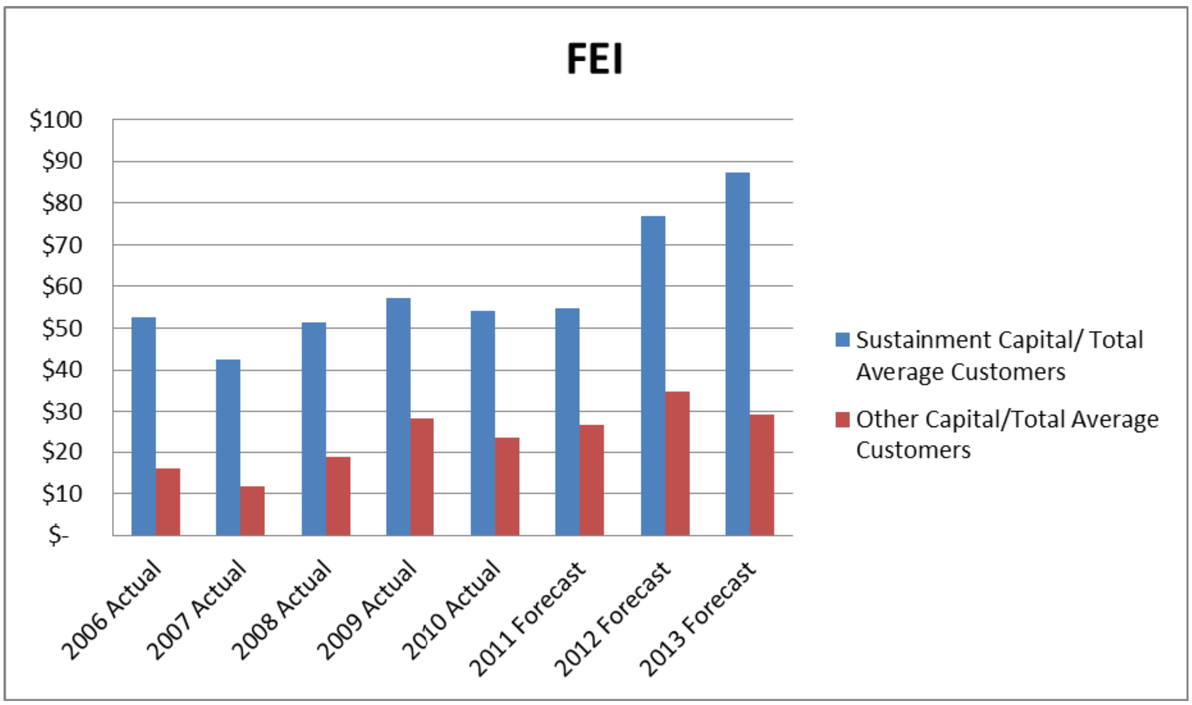
Note: No approved capital expenditure metrics are available for 2006, 2007 & 2010 as Fort Nelson did not apply for rates for these years.

33.2 Using the responses from the previous question, graph the Actual /Forecast Sustainment, Growth and Other Capital expenditures per customer as separate lines, with the years on the x-axis and the $/customer on the y-axis.

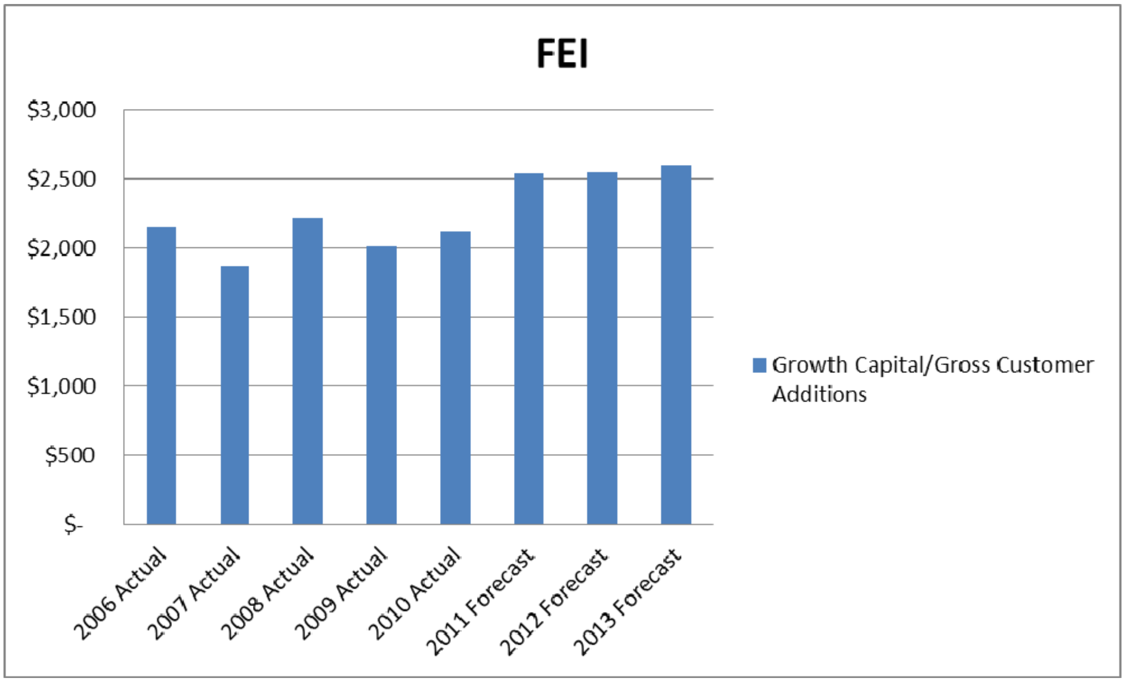
Response:

The graphs for Actual/Forecast Sustainment, Growth and Other Capital expenditures per customer are provided below.

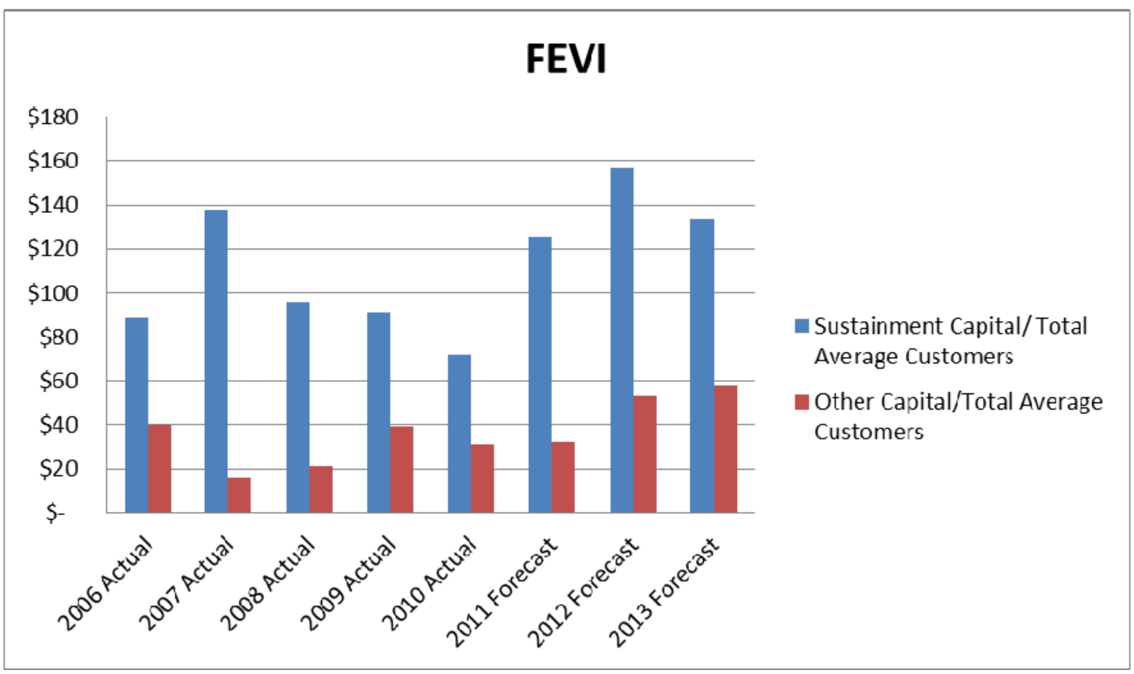
Mainland – Sustainment and Other Capital



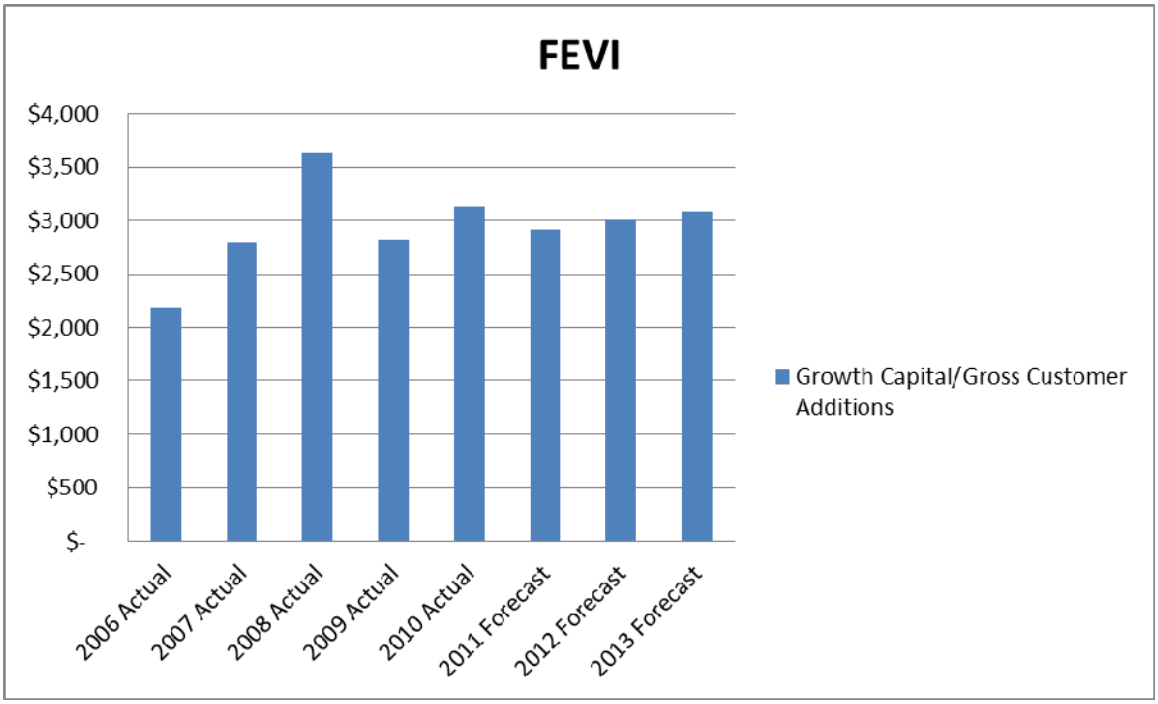
Mainland – Growth Capital



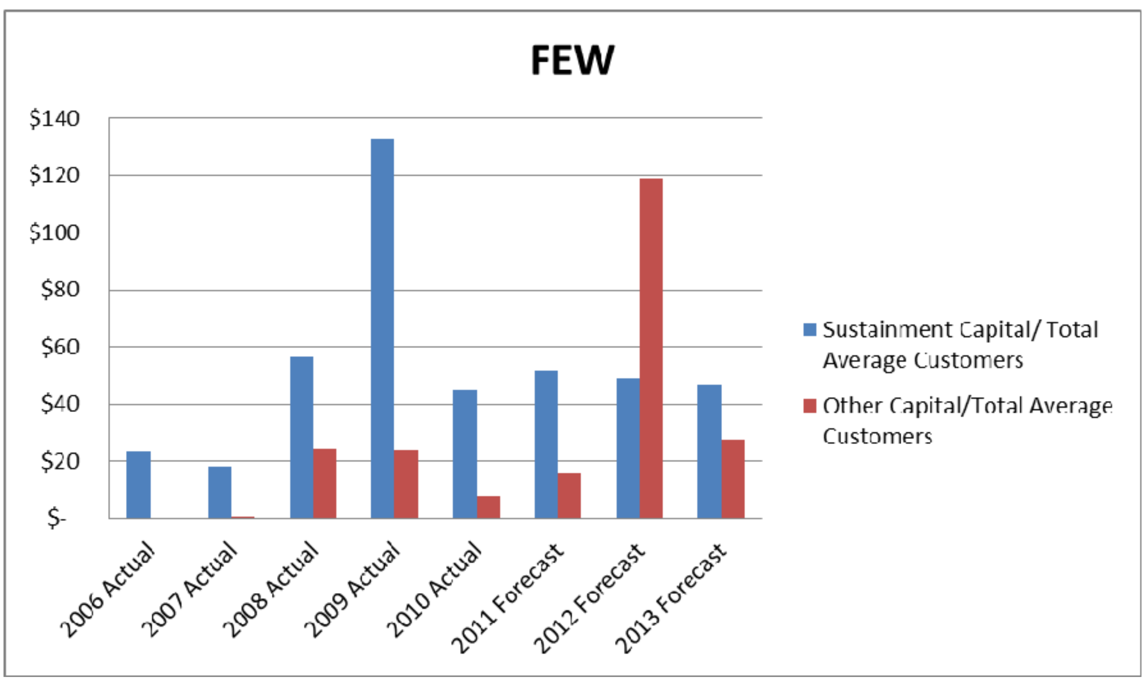
Vancouver Island - Sustainment and Other Capital



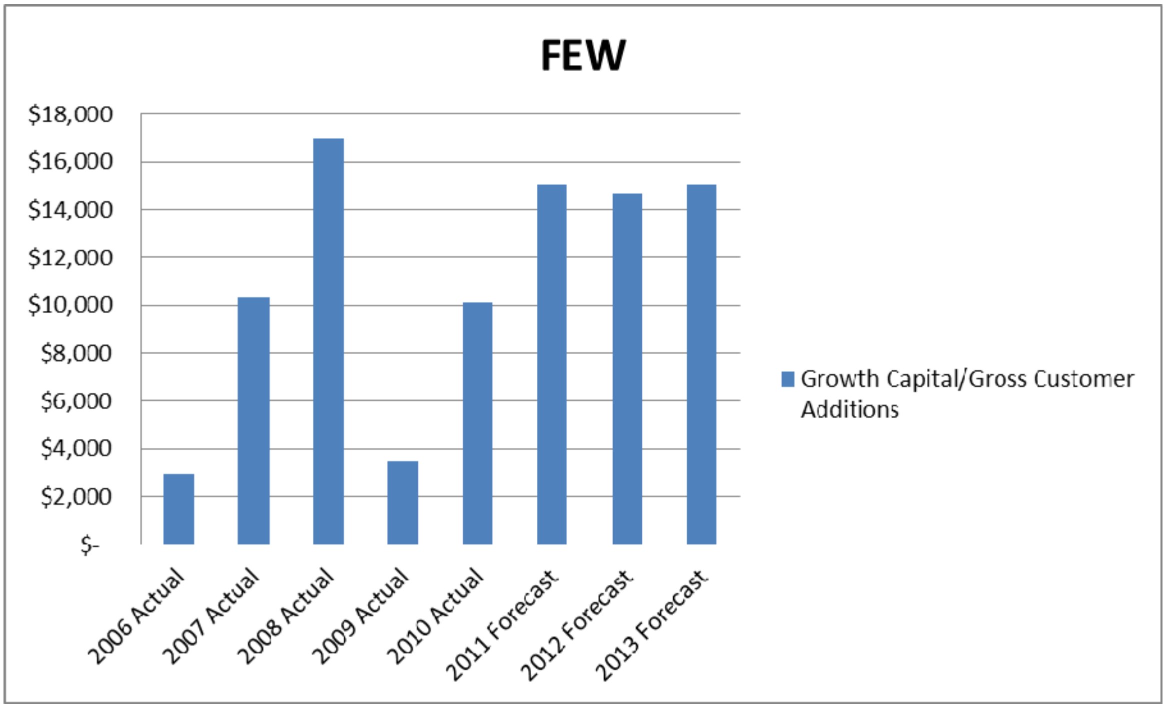
Vancouver Island - Growth Capital



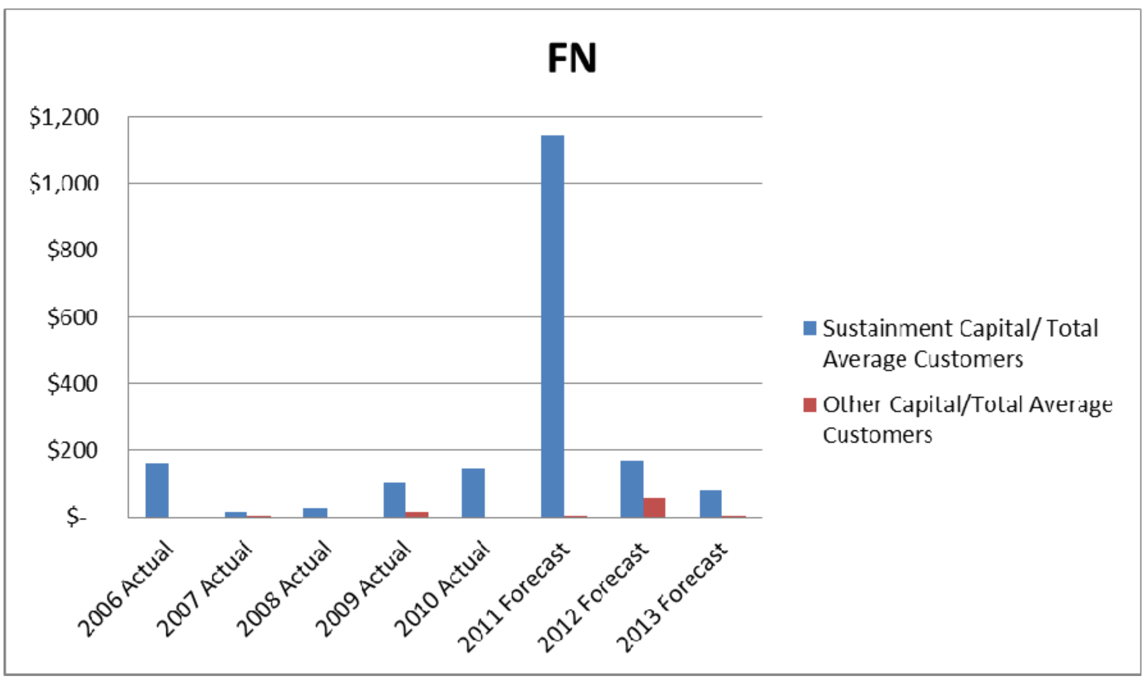
Whistler - Sustainment and Other Capital



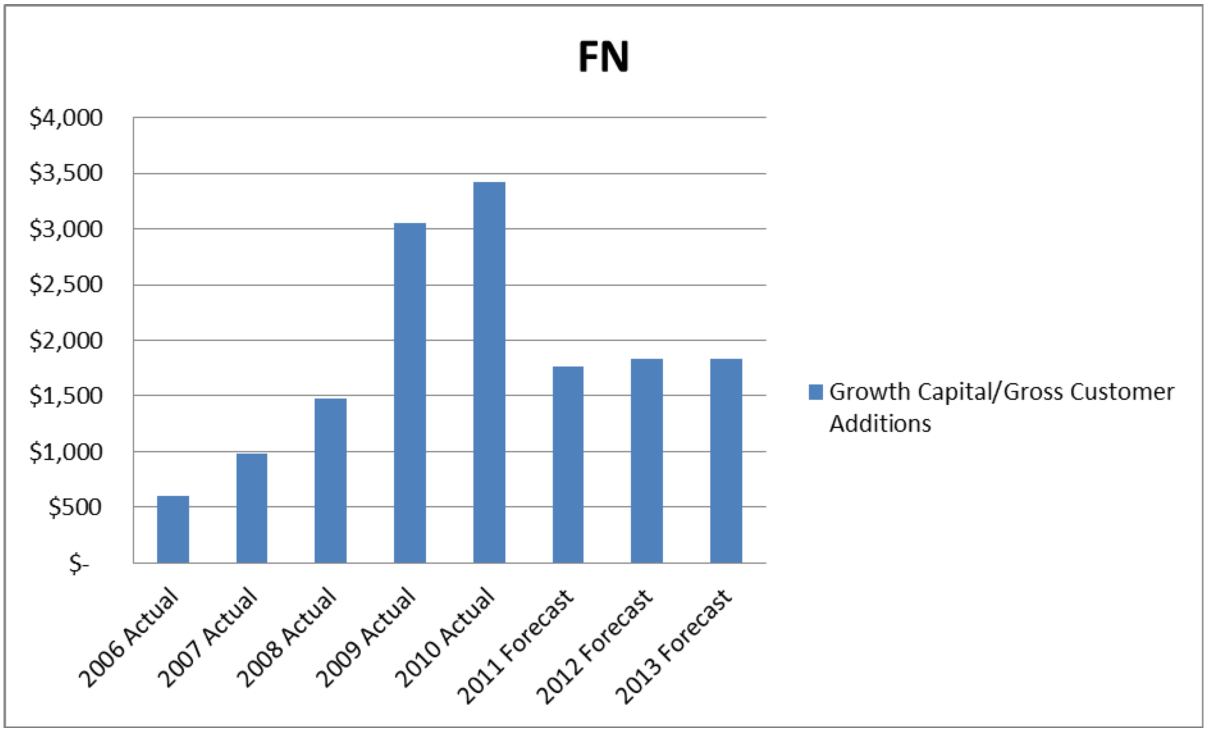
Whistler - Growth Capital



Fort Nelson - Sustainment and Other Capital



Fort Nelson - Growth Capital



34.0 Reference: Growth Capital Expenditures

Exhibit B-1, Part 4.4.3, p. 93 and Part 4.5.3, p. 105

System Extension and Customer Connection Policies Review Application, p. 15

Residential Main Extension

34.1 Please complete the Main Extension Analysis table below for FEI and FEVI using the appropriate main extension test for each year. Also provide the tables in fully functional electronic format.

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

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

Response:

As requested, the following Main Extension Analysis table has been completed.

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

Year	2006	2007	2008	2009	2010	2011
Use Per Customer (GJ/Year)	N/A	N/A	125	155	174	280
Average Main Cost	12,470	11,729	18,139	17,157	13,790	12,081
Average Service Line Cost	985	1,022	1,185	1,371	1,259	1,319
Maximum Capital Expenditure	$ 233,011	$ 176,947	$ 833,569	$ 254,851	$ 127,744	$ 162,495

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

Year	2006	2007	2008	2009	2010	2011
Use Per Customer (GJ/Year)	N/A	N/A	80	68	73	58
Average Main Cost	8,133	9,532	15,515	36,496	8,379	17,568
Average Service Line Cost	846	1,060	1,228	1,452	1,202	941
Maximum Capital Expenditure	$ 45,599	$ 268,563	$ 219,888	$ 1,917,898	$ 64,857	$ 238,628

2011 YTD as at May 31, 2011

Please refer to the Attachment 34.1 for the requested fully functional electronic format.

Use per customer (GJ/year) was derived by dividing total forecast consumption by the number of forecast attachments. FEI and FEVI are not able to provide use per customer for 2006 and 2007 as the data is not readily available. Consumption data from the Companies' Customer Attraction Front End ("CAFE") software system is available from 2008 onwards.

The average main cost and service line costs were derived from actual cost data. FEVI's average main cost and maximum capital expenditure were higher in 2009 due to the Shawnigan Lake project.

Maximum capital expenditure data was derived by taking the highest, actual capital cost main extension from the given year.

34.2 The FEVI residential use per customer is from forecast to decline by 22.1 percent from 2006-2013. Has the decline in customer use increased the number of uneconomic main extensions, Profitability Index (PI) less than 0.8? Please explain.

Response:

FEVI does not have any "uneconomic" main extensions with a forecasted PI less than 0.8.

If an MX test indicated a PI of less than 0.8, the main extension would only proceed provided that the shortfall in revenue was offset by contributions in aid of construction by customers to be served by the main extension.

Based on the past three years of data (2008 – 2010), no clear trend has developed with respect to the number of main extensions requiring a contribution in aid of construction. The data below provides the number of main extensions per year in FEVI that required a contribution in aid of construction:

- 2008 – 23 main extensions
- 2009 – 18 main extensions
- 2010 – 22 main extensions

35.0 Reference: Exhibit B-1, Application, Part 4.5.1, p.105 & Appendix C3 Spreadsheet

Vancouver Island – Residential and Commercial Use Rates

Since 2006, the UPC of the RGS-1 customer class has been declining by almost 2% per year. This is almost four times the decline rate of UPC of the Mainland region (Figure 4.5-1). FEVI believes that the trend will continue and provided a number of reasons: retrofit of appliances, changing housing mix, government policies and programs aimed at efficiency.

According to the frequency distribution tables for the four year period 2007 to 2010 for FEVI (Appendix C3), the total number of customers at FEVI increased by an average of 2.3% per annum (from 81,358 in 2007 to 88,998 in 2010) whereas the number of customers who consume between 0 to 10 GJ per year rose by an average of 9.1% per annum (from 5,823 to 8,258); and the customers here consume between 10 to 20 GJ rose by an average of 7.6% per annum (from 7,631 to 10,234).

35.1 Does FEVI believe that this increase in low-consumption customers is at the heart of a steeply declining UPC?

Response:

The average FEVI decline since 2006 has been approximately 1.9 GJ/yr or approximately 3.5 percent (Application, Exhibit B-1, Figure 4.5-1). The average Mainland decline has been approximately 1.1 GJ/yr or approximately 1.1 percent (Figure 4.4-2). FEVI is declining approximately 3 times as fast as Mainland. See table below.

Low consuming FEVI users account for 16 percent (in 2007) and 20 percent (in 2010) of all FEVI customers.

There are many factors implicit in the declining UPC and the increase of low consumption customers is one of them. Energy Efficiency and Conservation (EEC), customer behaviour and improved appliance efficiency in the newer Island housing stock are three factors likely also affecting the decline. While we know that there are many factors contributing to the decline, we are not able to state with certainty the relative contribution of each factor. The frequency distribution tables do not provide the mix of new and existing customers. FEVI believes it is reasonable to assume that changes in existing customer behaviour account for a portion of these low volume customers.

Year	FEVI UPC, GJ	% Decline	FEI UPC, GJ	% Decline
	4.5-1		4.4-2	
2006	60.2		96.8	
2007	57.0	5.3%	96	0.8%
2008	56.1	1.6%	92.5	3.6%
2009	53.5	4.6%	93.3	-0.9%
2010	52.5	1.9%	92.6	0.8%
Aggregate Decline, GJ	7.7		4.2	
Avg Annual Decline	1.9	3.3%	1.1	1.1%
Ratio	1.8	307.5%		

35.2 Would FEVI agree that its forecast methodology will have to be revised from the current trend analysis If FEVI were to engage in a corporate strategy to market to customers who would use natural gas space and water heating instead of targeting new customers who are, say, fireplace only?

Response:

The FEU have always and will continue to engage in corporate strategies that market to customers who would use natural gas for space and water heating. The methodologies used in the forecast of short-term demand implicitly capture all the factors at play, including appliance mix. As a result, the FEU do not believe that the short-term forecast methodologies would need to be revised.

Further, the analysis and frequency distribution tables are not able to tell us the mix of new and existing customers in the low volume groups. The FEU believe it is reasonable to assume that a percentage of these low volume users are existing customers not subject to corporate marketing strategies that target new customers.

Finally, it should be noted that changes in demand patterns for new customers are diluted by the large existing customer base, so changes such as the one described could be expected to have a relatively small short-term effect.

35.3 According to Figure 4.5-1, the UPC in 2011 is 50.5 GJ. Please provide the data on customer consumption categories in the following table:

GJ	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0-24								
25-49								
50-74								
75-99								
Over 100								
TOTAL								

Response:

The following table depicts proportion of residential customer share over 2007 – 2010, by consumption categories.

Mainland

	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0 To 25	40,038	5%	43,195	6%	42,561	6%	47,698	6%
25 To 50	74,960	10%	83,301	11%	82,889	11%	93,492	12%
50 To 75	148,871	20%	162,991	22%	160,847	21%	168,637	22%
75 To 100	186,117	25%	189,020	25%	187,558	25%	184,436	24%
Over 100	289,149	39%	267,675	36%	276,514	37%	262,620	35%
Total	739135	100%	746182	100%	750369	100%	756883	100%

Vancouver Island

	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0 To 25	17,581	22%	19,911	24%	21,842	25%	23,951	27%
25 To 50	22,132	27%	23,564	28%	25,094	29%	26,861	30%
50 To 75	20,280	25%	20,949	25%	21,560	25%	21,449	24%
75 To 100	13,031	16%	12,495	15%	11,606	13%	10,758	12%
Over 100	8,334	10%	7,492	9%	6,720	8%	5,979	7%
Total	81,358	100%	84,411	100%	86,822	100%	88,998	100%

Whistler

	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0 To 25	607	29%	620	30%	700	32%	685	31%
25 To 50	290	14%	302	14%	300	14%	330	15%
50 To 75	258	12%	271	13%	275	13%	276	13%
75 To 100	229	11%	219	10%	223	10%	239	11%
Over 100	685	33%	674	32%	689	32%	669	30%
Total	2,069	100%	2,086	100%	2,187	100%	2,199	100%

Fort Nelson

	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0 To 25	16	1%	12	1%	13	1%	21	1%
25 To 50	45	2%	47	2%	41	2%	63	3%
50 To 75	120	6%	139	7%	114	6%	146	8%
75 To 100	318	16%	329	17%	283	15%	392	20%
Over 100	1,431	74%	1,409	73%	1,477	77%	1,315	68%
Total	1,930	100%	1,936	100%	1,928	100%	1,937	100%

Aggregate

	2007 Customers	2007 Percentage Share	2008 Customers	2008 Percentage Share	2009 Customers	2009 Percentage Share	2010 Customers	2010 Percentage Share
0 To 25	58,242	7%	63,738	8%	65,116	8%	72,355	9%
25 To 50	97,427	12%	107,214	13%	108,324	13%	120,746	14%
50 To 75	169,529	21%	184,350	22%	182,796	22%	190,508	22%
75 To 100	199,695	24%	202,063	24%	199,670	24%	195,825	23%
Over 100	299,599	36%	277,250	33%	285,400	34%	270,583	32%

36.0 Reference: Exhibit B-1, Application, Part 4.6.3

Whistler – Commercial Use Rates

FEW is forecasting a decline in UPC for the LGS-2 rate class by 6 percent annually and for the LGS-3 by 17 percent annually for the test period.

36.1 How many customers are currently in the LGS-2 and LGS-3 rate classes? If possible, please provide a description of the nature of business of the largest customers in LGS-2 and LGS-3.

Response:

In December 2010, there were 49 customers in Rate Class LGS-2 and 23 customers in Rate Class LGS-3.

Due to unreliable NAICS coding, FEW cannot reliably determine the nature of business for these customers. However, due to the small number of customers in these rate classes, a review of the customer names revealed that of the ten (10) largest consuming customer in 2010 in the Rate Class LGS-2, four (4) appeared to be resorts or hotels and four (4) appeared to be strata corporations.

For Rate Class LGS-3, of the ten (10) largest consuming customers in 2010, five (5) appear to be strata corporations and at least one (1) appears to be a hotel. The remaining includes a holding company where the nature of business is undetermined.

36.2 It appears from the tables in Appendix C3 that the forecast variances for UPC for the large commercial customer groups are over 20%. To counter the forecasting error, has FEW considered conducting surveys on large commercial customers to assess test year consumption? If not, why not.

Response:

In the past we have not surveyed commercial customers due to the large customer base and resulting labour costs associated with our survey methodology. Automation improvements being planned for our Industrial survey may allow us to add this capability in the future. A small change in the Commercial UPC forecast methodology would be required to incorporate the results of such a survey.

Commercial surveys could be expected to provide useful results in smaller regions such as Whistler and Fort Nelson where demand patterns changes in a small number of customers can significantly affect the rate class average. The value added by doing a commercial survey in Mainland and Vancouver Island may not produce better results because the effect of large demand changes in a small number of customers is averaged over the much larger customer base.

37.0 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).

37.1 Please provide the NYMEX natural gas futures five-day average forward prices at February 15, 16, 17, 18, and 22, 2011 that were used to calculate the commodity portion of the Cost of Gas in Table 5.2-2 for each of the three years.

Response:

The table below provides the NYMEX natural gas forward prices as of February 15 – 22, 2011 as used to calculate the five-day average forward prices utilized in the gas cost forecasts.

NYMEX Natural Gas Forward Prices as of February 15 - 22, 2011

	Feb 15 NYMEX *($US/MMBtu)*	**Feb 16 NYMEX** *($US/MMBtu)*	**Feb 17 NYMEX** *($US/MMBtu)*	**Feb 18 NYMEX** *($US/MMBtu)*	**Feb 22 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	$ 3.976	$ 3.921	$ 3.868	$ 3.876	$ 3.867	$ 3.902
Apr-11	$ 4.030	$ 3.961	$ 3.901	$ 3.906	$ 3.907	$ 3.941
May-11	$ 4.097	$ 4.030	$ 3.968	$ 3.976	$ 3.976	$ 4.009
Jun-11	$ 4.153	$ 4.088	$ 4.030	$ 4.037	$ 4.038	$ 4.069
Jul-11	$ 4.210	$ 4.143	$ 4.087	$ 4.095	$ 4.096	$ 4.126
Aug-11	$ 4.244	$ 4.175	$ 4.118	$ 4.125	$ 4.128	$ 4.158
Sep-11	$ 4.253	$ 4.187	$ 4.130	$ 4.135	$ 4.139	$ 4.169
Oct-11	$ 4.299	$ 4.233	$ 4.176	$ 4.180	$ 4.185	$ 4.215
Nov-11	$ 4.486	$ 4.425	$ 4.371	$ 4.376	$ 4.382	$ 4.408
Dec-11	$ 4.721	$ 4.658	$ 4.613	$ 4.616	$ 4.627	$ 4.647
Jan-12	$ 4.846	$ 4.783	$ 4.742	$ 4.748	$ 4.760	$ 4.776
Feb-12	$ 4.836	$ 4.774	$ 4.732	$ 4.738	$ 4.749	$ 4.766
Mar-12	$ 4.766	$ 4.704	$ 4.669	$ 4.678	$ 4.690	$ 4.701
Apr-12	$ 4.610	$ 4.557	$ 4.530	$ 4.538	$ 4.555	$ 4.558
May-12	$ 4.633	$ 4.584	$ 4.559	$ 4.568	$ 4.587	$ 4.586
Jun-12	$ 4.665	$ 4.616	$ 4.593	$ 4.603	$ 4.621	$ 4.620
Jul-12	$ 4.705	$ 4.656	$ 4.634	$ 4.644	$ 4.661	$ 4.660
Aug-12	$ 4.732	$ 4.683	$ 4.664	$ 4.674	$ 4.691	$ 4.689
Sep-12	$ 4.742	$ 4.693	$ 4.670	$ 4.680	$ 4.698	$ 4.697
Oct-12	$ 4.799	$ 4.750	$ 4.723	$ 4.731	$ 4.748	$ 4.750
Nov-12	$ 4.949	$ 4.900	$ 4.876	$ 4.886	$ 4.908	$ 4.904
Dec-12	$ 5.164	$ 5.118	$ 5.094	$ 5.101	$ 5.123	$ 5.120
Jan-13	$ 5.292	$ 5.250	$ 5.226	$ 5.231	$ 5.253	$ 5.250
Feb-13	$ 5.269	$ 5.228	$ 5.206	$ 5.211	$ 5.233	$ 5.229
Mar-13	$ 5.174	$ 5.136	$ 5.116	$ 5.121	$ 5.143	$ 5.138
Apr-13	$ 4.954	$ 4.921	$ 4.911	$ 4.911	$ 4.938	$ 4.927
May-13	$ 4.954	$ 4.921	$ 4.913	$ 4.913	$ 4.941	$ 4.928
Jun-13	$ 4.979	$ 4.946	$ 4.941	$ 4.941	$ 4.970	$ 4.955
Jul-13	$ 5.019	$ 4.986	$ 4.981	$ 4.981	$ 5.011	$ 4.996
Aug-13	$ 5.049	$ 5.016	$ 5.011	$ 5.011	$ 5.042	$ 5.026
Sep-13	$ 5.059	$ 5.026	$ 5.026	$ 5.026	$ 5.058	$ 5.039
Oct-13	$ 5.119	$ 5.086	$ 5.086	$ 5.086	$ 5.119	$ 5.099
Nov-13	$ 5.254	$ 5.221	$ 5.223	$ 5.221	$ 5.254	$ 5.235
Dec-13	$ 5.459	$ 5.431	$ 5.435	$ 5.433	$ 5.466	$ 5.445

Notes: (A) NYMEX three day average closing settlement price.

37.2 Given that there is not a currently an approved Price Risk Management Plan (PRMP) in place for FEVI for the 2011 through 2013 period, please describe the assumptions regarding the status of the PRMP and the hedging strategies that were used to calculate the forecast hedging costs / (gains) in Table 5.2-2.

Response:

FEVI did not make any assumptions regarding the status of the PRMP and the hedging strategies that were used to calculate the forecast hedging costs/(gains) in Table 5.2-2. The forecast hedging costs/(gains) presented in Table 5.2-2 are based upon mark-to-market values based on the forward prices at the time the forecast was prepared for existing hedges in place. The existing hedges in place were implemented according to the FEVI (formerly TGVI) 2009-2014 Price Risk Management Plan, which was approved by the Commission per Letters No. L-36-09 and No. L-45-09 dated June 8, 2009 and June 11, 2009, respectively, and represents 50 percent of the maximum hedgeable volumes for 2012 and 2013. As FEVI does not currently have an approved Price Risk Management Plan in place, no other hedges, other than existing hedges, were assumed in the forecast cost of gas. The mark-to-market values were calculated based on the NYMEX natural gas five-day average futures prices for February 15, 16, 17, 18, and 22, 2011.

37.3 Please provide a breakdown of the cost of gas to show the unaccounted for gas, company use gas, carbon tax and CMAE cost components for 2011, 2012 and 2013.

Response:

A table providing a further breakdown of the Vancouver Island 2011-2013 cost of gas, excluding royalty revenues and GCVA impacts, is shown below.

Amounts in $ Thousands	**2011 Projected**	**2012 Forecast**	**2013 Forecast**
UAF	$ 690	$ 744	$ 766
Company Use	931	1,115	1,219
Carbon Tax	464	539	606
Commodity	36,756	44,430	49,328
Transportation Demand Charges	7,451	8,173	7,584
Storage Demand Charges	3,457	3,499	3,432
Hedging Cost / (Gain)	16,394	15,174	12,786
CMAE	414	442	457
Other Gas Supply Management Costs	216	221	221
Total Cost of Gas	**$ 66,773**	**$ 74,337**	**$ 76,399**

38.0 Reference: Cost of Service

Exhibit B-1, Application, Section 5.2.2.1, p. 137

Amalgamation of Annual Contracting Plans

38.1 Please confirm that FEU intends to amalgamate the FEI and FEVI gas procurement portfolios effective November 1, 2012 co-incident with the start of the 2012/2013 contract year.

Response:

Confirmed. The FEU are intending to propose combining the gas procurement portfolios at the start of the 2012/13 gas contract year effective November 1, 2012. This proposal is discussed in the FEU 2011/12 Annual Contracting Plan that was confidentially filed on May 25, 2011, with the Commission. Moving to a single gas portfolio will require approval by the Commission and the FEU anticipate filing an application with Commission seeking such approval by the third quarter of 2011.

38.2 What are the potential implications of amalgamating the gas procurement portfolios two months in advance of the full amalgamation?

Response:

The FEU do not envisage any material implications arising from combining the gas portfolios two months in advance of full amalgamation (if approved); in fact, it is the FEU's intention to combine the gas portfolios whether or not full amalgamation is approved.

The reason the FEU have proposed to combine the gas procurement portfolios effective November 1, 2012, is to coincide with the standard industry contract year, often referred to as the "gas contract year". In other words, gas supply and midstream resources are generally contracted based on a gas contract year that begins each November 1 and concludes the following October 31. The combined pool of gas supply contracting and resources are not expected to change in any material way on a total basis in order to meet the Companies' winter and peak day loads under a combined portfolio. However, as the Companies are expected to maintain their current legal, regulatory and accounting framework until December 31, 2012, the costs from the combined portfolio will have to be reallocated back to the individual entities for the two months of November and December 2012. 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.

As discussed in the response to BCUC IR 1.38.1, the FEU anticipate filing an application for approval to combine the gas portfolios in the third quarter of 2011. Such application will include a description of the gas cost recovery methodology from the entities for the two month period (November and December 2012) and for subsequent calendar years if full amalgamation does not proceed.

38.3 Please confirm that FEU intends to proceed with the amalgamation of the FEI and FEVI gas procurement portfolios regardless whether or not the full amalgamation of the utilities proceeds.

Response:

Confirmed. The FEU are proposing to proceed with the amalgamation of the gas portfolios regardless of the decision on full amalgamation. Please refer to the response BCUC IR 1.38.6 for a description of the benefits of moving to a single gas portfolio. It is FEU's view that these benefits would be realized whether or not full amalgamation of the Utilities proceeds.

38.4 What are the potential implications of amalgamating the gas procurement portfolios in the event the full amalgamation does not proceed effective January 1, 2013?

Response:

It is FEU's view that the benefits of a combined gas procurement portfolio can be realized even in the event full amalgamation does not proceed. As discussed in the response to BCUC 1.38.6, a combined portfolio enables greater operational effectiveness, greater contracting flexibility and streamlined regulatory processes across the FEU. The management of the daily load on a combined basis provides for an effective use of resources, while the forecasting of future growth jointly within the FEU could result in further optimization opportunities within a single combined portfolio over time. The contracting flexibility from additional counterparties for supply and the diversity and mitigation activities from incremental resources, under a single portfolio, will benefit all core customers of the FEU.

One of the key implications if full amalgamation does not proceed is to ensure that gas portfolio costs are appropriately recovered from the various rate classes of customers within the individual entities. An assessment of the methodologies for recovery of gas costs from the customers within the different entities is being developed and will be discussed as part of the application for approval to combine the gas portfolios, which is expected to be filed in the third quarter of 2011.

38.5 Please confirm that FEU will track the costs of the gas procurement portfolios separately with respect to the FEI and FEVI utilities in the event that the full amalgamation does not proceed effective January 1, 2013. Describe how FEU will allocate and track these costs.

Response:

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. The methodologies are being developed and will be discussed within the application for approval to combine the gas portfolios expected to be filed later in 2011.

38.6 Please describe the benefits of a combined gas portfolio; in particular, the operational, contracting and regulatory efficiencies that may be realized.

Response:

A combined portfolio structure enables greater operational effectiveness, expanded contracting flexibility and regulatory efficiency. Furthermore, the objectives of providing secure and reliable gas supply at minimal cost would continue to be met effectively under a single combined gas portfolio.

Operational Effectiveness:

The total pool of available resources can be more effectively used under a single portfolio, in order to manage the total system load on a daily basis. Under a combined portfolio, only a single set of nominations will be required on a daily basis on the various pipeline systems. The FEU will be able to access gas supply from a complete pool of resources at short notice each day, in order to meet the total intraday load, especially during periods of cooler weather when more resources are required. In the event of plant outages on the Westcoast system, or extreme weather conditions, gas supply from Alberta could be sourced to aid in meeting the daily load even for the FEVI system. Diversity from one set of total available resources, to service the entire system load of the FEU, is expected to provide greater efficiency from a resource contracting and use perspective over the long term. Also, the annual forecasting of load versus the resources available and contracted to meet that demand is currently conducted at the individual entity level. The FEU's ability to match resources available in the region, against total system growth, would be potentially better forecast in the long term on a combined portfolio basis.

Contracting Flexibility:

A single set of counterparties would be available for the FEU to contract and procure gas supply required to meet the normal and design peak day load. Currently, FEI has a broad range of counterparties available for that entity only to enter into supply contracts. By using the counterparties available to FEI to contract under a single portfolio, the FEU will be better able to manage supply contracts, nominations and month-end processes. Furthermore, customers of FEVI will also benefit from an increase in the number of counterparties available for contracting for gas supply. Over the past few years, producer companies have been bought and sold resulting in changes or elimination of counterparty contracts, thus requiring FEI and FEVI to separately modify and novate their individual master purchase agreements. A single set of counterparties will result in only one master agreement with a supplier, and any modifications arising from ownership changes will need to be administered only once including filings with the Commission. Furthermore, as new creditworthy counterparties emerge in the industry, the FEU will have to negotiate only a single master agreement in order to serve all customers. Also, under a combined portfolio, the FEU may be able to realize a greater level of optimization due to the availability of a larger portfolio of resources combined with a single diverse set of counterparties.

Regulatory Efficiency:

The development of a single gas portfolio would result in streamlining the preparation and submission of key gas supply filings, such as the ACP and energy supply contracts, while eliminating the need for intercompany subleasing agreements for storage contracts. This would reduce the number of filings and issuance of orders between the individual entities of the FEU and the Commission each year, therefore providing greater regulatory efficiency.

Conclusion:

The Companies believe that a single combined gas portfolio is in the best interest of all core customers of the FEU. A combined gas portfolio, with consistent gas cost allocation methodology, provides the platform for consistent program offerings within the FEU such as the Customer Choice Program. Currently, only customers of FEI benefit from the Essential Services Model ("ESM") that allows customers to fix their commodity rates with a commodity provider of their choice. An expansion of this program can be facilitated to all customers, with efficiency, if the ESM model is implemented across the FEU including consistent cost accounting and allocation methodology. A single gas portfolio across the FEU would create greater effectiveness and efficiencies, in order to continue to successfully meet the objectives of the ACP.

39.0 Reference: Exhibit B-1, Application, p. 141

Company Use Gas and Unaccounted For Gas Volumes

On page 141 the Application states: *"UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Consistent with past practice, the UAF percentages are calculated based on the average historical recorded UAF percentages."*

39.1 Please provide the historical recorded UAF percentages in each year over the period 2006 – 2010 for each of the Mainland, Vancouver Island, Whistler and Fort Nelson systems.

Response:

The table below provides the historical recorded annual UAF percentages for the various the FEU service areas over the period 2006 – 2010.

Recorded UAF by Service Area

Year	Lower Mainland	Inland	Columbia	Fort Nelson	Revelstoke [1]	Whistler [2]	Vancouver Island
2006	1.16%	0.21%	3.72%	1.60%	2.21%	3.99%	0.29%
2007	-0.10%	-0.45%	1.03%	0.47%	3.87%	4.68%	0.86%
2008	-0.33%	0.21%	0.16%	1.51%	4.82%	3.80%	0.15%
2009	-0.30%	-0.63%	-0.62%	0.37%	2.25%	1.85%	0.03%
2010	0.02%	0.12%	-0.45%	1.09%	3.05%	0.02%	0.11%

Notes: 1. Revelstoke is a propane distribution system.
2. Whistler was a propane distribution system until mid-2009.

39.2 Following the amalgamation of its four utilities, does FEU intend to continue to calculate and monitor UAF on a system by system basis?

Response:

Yes. The FEU currently track and monitor UAF on a service-area basis. Following amalgamation of the Utilities, the FEU will continue to track and monitor UAF on an appropriate system basis, with the future allocation and cost recovery related to UAF to be determined pursuant to the outcome of the Amalgamation and Rate Design Phase 'A' application that will be filed in fall 2011.

40.0 Reference: Cost of Service

Exhibit B-1, Section 5.2.4.4, p. 142

CMAE Budget Requirements

In its 2009-2010 Revenue Requirements application, TGI requested and received approval to increase the base Core Market Administration Expense (CMAE) costs to include a transfer of direct and indirect costs from O&M.

40.1 Please provide a breakdown of CMAE actual, projected and forecast annual expenditures for each year from 2010 through 2013 by completing the following table, including the indicated line items for the direct cost associated with the transfer of O&M costs and the indirect costs for the shared services.

	2010 Approved	**2010 Actual**	**2011 Approved**	**2011 Projection**	**2012 Forecast**	**2013 Forecast**
IT						
Consulting & Legal						
Sundries & Subscriptions						
Training & Travel						
Labour						
Energy Management Services Revenue						
Transfer from O&M						
Shared Services						
Total	$4,011	$3,677	$4,147	$4147	$4,424	$4,569

<u>Response:</u>

Please see the table below for a breakout of CMAE costs. Direct costs associated with the transfer of O&M are listed under "Transfer from O&M" and indirect costs associated with the transfer of O&M are listed under "Shared Services".

Table BCUC IR1.40.1 - CMAE Breakout

Amounts in $ Thousands

Cost Component	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
IT	279	249	282	320	485	502
Consulting & Legal	290	313	311	313	315	325
Sundries & Subscriptions	193	192	194	180	200	207
Training & Travel	210	134	214	232	172	176
Labour	1,809	2,235	1,871	2,534	2,703	2,799
Energy Management Services Revenue	(171)	(171)	(177)	(177)	(197)	(207)
Transfer from O&M	676	-	707	-	-	-
Shared Services	725	725	745	745	746	767
Total	**4,011**	**3,677**	**4,147**	**4,147**	**4,424**	**4,569**

Based on the approval granted in the 2010-2011 Revenue Requirements Application, all direct O&M costs that the Company requested for transfer to CMAE were completed, with a corresponding decrease in the O&M budget. This direct transfer was a one-time adjustment and no additional amounts were requested as part of the 2012-2013 Revenue Requirements Application. These one-time adjustments are the amounts shown under "Transfer from O&M" for "2010 Approved" and "2011 Approved" and represent almost exclusively two components – the first being the labour costs of the gas accounting employees who complete activities related to services provided by Gas Supply and the second being the Company incentive payments for staff in the Gas Supply department. Once these costs were transferred they were no longer managed as stand-alone items and are rather included as part of overall labour costs incurred by employees working in Gas Supply and part of CMAE.

Consistent with the allocation methodology proposed in the 2004 Annual Review, establishing rates effective January 1, 2005, and accepted by the Commission under Order No. G-112-04, the CMAE costs, related to the integrated gas supply function, continue to be allocated 90 percent to FEI, which now includes FEW in its gas supply portfolio, and 10 percent to FEVI. Also consistent with current practice the FEI, including FEW, share of the CMAE is allocated 30 percent to the CCRA and 70 percent to the MCRA. Any variances from approved amounts, such as the $334 thousand favourable variance experienced in 2010, are captured in the various gas cost deferral accounts and flow back to customers.

40.2 Please confirm that the O&M expense forecast reflects the transfer of any direct costs and indirect Shared Services costs to the CMAE budget. Provide details regarding the amount of the O&M expense transferred to the CMAE budget, broken out by the department that the costs were transferred from.

Response:

Yes, FEI's O&M forecast for 2012 and 2013 includes an offset that reflects the charging of Shared Services costs to the CMAE budget. Based on the approval granted in the 2010-2011 Revenue Requirements Application, all direct O&M costs that FEI requested for transfer to the CMAE were completed, with a corresponding decrease in the O&M budget. This direct transfer was a one-time adjustment and no additional amounts were requested as part of the 2012-2013 Revenue Requirements Application.

Indirect O&M costs are included in a Shared Services fee that result in a charge to CMAE and an equal offset to FEI's O&M costs. The services included in the Shared Services fee and methodology used to determine the fee amount included in this Application is the same as that described and approved in the 2010-2011 Revenue Requirements Application. The services included in the Shared Services fee and their amounts are set out in the table below:

Table BCUC IR1.40.2 - Indirect O&M Cost Breakout (Shared Services Fee)

Amounts in $ Thousands

Department	Service	2012 Forecast	2013 Forecast
VP, Energy Supply & Resource Development	Management oversight	201	207
Marketing	Core customer loading forecasting	178	184
IT and Facilities	Support services, office space, materials	227	232
Legal Counsel	Contracts review	74	76
Credit Risk Management	Contract negotiation, counterparty credit analysis	67	69
Total		**746**	**767**

The forecast amount for 2012 is at the same approximate level as that projected for 2011, after adjusting for a reduced cost of some components and the addition of standard inflation for labour and materials. The amount for 2013 includes standard inflation for labour and materials expected over 2012.

41.0 Reference: Cost of Service

Exhibit B-1, Application, Section 5.2.4.4, p. 143

CMAE Budget Requirements

"The increase in expenditures forecast for 2012 is caused by the need for an additional employee required to assist in the completion of Gas Supply activities, by labour and materials inflation, and the need to support several enhancements to the information systems used by Gas Supply."

41.1 Please describe the nature of the Gas Supply activities that the additional employee is required to assist in the completion of?

Response:

The Gas Supply staff work as a integrated team to plan, manage and implement the gas resource portfolio development and procurement, midstream operations and daily optimization and mitigation. The requirement for an additional employee was identified due to a re-alignment of responsibilities within the team in response to increased levels of activity and the need to be better positioned to manage employee development and succession planning.

The increased level of activities include the following:

- Monitoring and developing responses to third-party regulatory and market developments that have the potential to impact availability and costs of contracted resources within the gas portfolio. It was determined that greater focus and attention is needed in this area because of the significant changes in terms of shale gas development and third-party pipeline developments and initiatives (e.g. Horn River, Montney, TransCanada and Spectra developments, Kitimat and other LNG export proposals, Ruby pipeline impacts) as well as changes to North American markets in general.

- Monitoring and developing new strategies to respond to constraints in regional storage capacity and changing market fundamentals to meet gas portfolio requirements. This work includes managing yearly storage and redelivery contracting and negotiations. This work also includes assessing and recommending future storage requirements and associated redelivery.

- Increased level of regulatory activities, working groups and submissions directed by the Commission including but not limited to North East market studies, review of price risk management objectives, gas mitigation activities and incentive plans, CCRA/MCRA rate setting mechanisms.

- Managing employee development to ensure the appropriate level of market expertise and experience on an on-going basis and to continue to support the level of activities in light of employee changes and transfers, competitive challenges and potential for impending retirements.

As a result of these requirements, in 2011 an existing long-term employee who was acting as a resource manager was appointed to a new senior advisor position established to focus primarily on expanded involvement in third-party regulatory issues and market developments, and external stakeholders. This position was also established to provide advice and coaching to newer and/or more junior employees to support market knowledge transfer and future succession planning. Subsequently, a market analyst was promoted to assume the resource manager responsibilities, which resulted in further changes and alignment of responsibilities among employees and the hiring of a new market analyst.

These changes, including the need for an additional employee, are required and prudent in order to be able to continue to manage the reliability and costs of the gas and midstream resources in the current market environment, and are in the best interests of customers.

41.2 On page 143 of the Application, FEU notes that 2010 expenditures were lower than approved in 2010 due in part to several vacant positions that were not filled until later in the year. Given that FEU made due in 2010 while being "short-staffed", please describe the change in circumstances that lead to a further increase in staffing requirements.

Response:

During the period of the vacancies, while the Company searched for appropriate gas cost accounting replacement employees, some of the work requirements were shared with existing employees and an external consultant was hired to help complete the remaining work requirements. While it was possible to complete the required work on this basis for the short-term, this was not the best long-term solution. Filling the vacancies helps to ensure that a sufficient group of employees is available to complete these specialized activities over the long term.

For clarity, these work activities associated with the vacant positions referred to on page 143 of the Application (Exhibit B-1), are different from the work activities resulting in the need for an additional employee required by Gas Supply. The work activities associated with the short-term vacancies are back-office in nature and limited to gas cost accounting. As discussed in the response to BCUC IR 1.41.1, the new employee in gas supply is the result of increased level of market activity and subsequent realignment of responsibilities. The cost of this additional position is currently being offset through cost savings in the 2011 CMAE budget but given that this position will continue to be operationally required after 2011, additional funding is being requested for this position starting in 2012.

41.3 Please describe the nature of the proposed enhancements to the information systems. Which systems are being enhanced and what business requirements are driving the need for the enhancements?

Response:

The enhancements FEI is planning to make relate to systems used to complete gas cost forecasts, and to how counterparty credit information is obtained, distributed to FEI's traders, and managed.

In the case of gas cost forecasting, FEI uses an end-of-life Microsoft Access Database tool for managing much of the data that feeds the gas cost forecasting process. This process is critical because it is used to evaluate the need for quarterly commodity cost adjustments that the FEU are required to complete. The database that is used in this process is at risk of being unsupportable given its age. FEI is in the process of evaluating alternatives to this database and has included an estimate of the incremental costs that will be incurred to support a new application.

Counterparty credit information is currently obtained and tracked using a number of manual methods. This approach can be improved with the greater use of technology so that this information is more current, and so that it is easier to identify changes in the credit outlook of counterparties the FEI does business with or is considering doing business with. This information can also be presented to traders in a manner that is more automated, so that it is easier to identify when the credit outlook of a counterparty has changed and communicate it to traders. This ability to effectively manage counterparty credit risk is critical to successfully managing gas costs on behalf of customers. FEI is in the process of evaluating alternatives, ranging from enhancements to the existing deal capture system to standalone solutions, and has included an estimate of the incremental costs that will be incurred to support the enhancements that are being considered.

42.0 Reference: Cost of Service

Exhibit B-1, Application, Section 5.2.4.4, p. 142

CMAE Budget Requirements

42.1 Does the forecast of CMAE budget requirements for 2013 as set out in Table 5.2-3 include any cost savings arising from the amalgamation of the gas procurement portfolios?

Response:

No, the CMAE budget for 2013 as set out in Table 5.2-3 (Application, Exhibit B-1) does not contemplate any cost savings arising from the amalgamation of the gas procurement portfolios. Please refer to the response to BCUC IR 1.42.1.1 for further discussion.

42.1.1 If so, please describe and quantify the forecast impact on the budget requirements for 2013 relative to 2012. If there are no cost savings arising from the amalgamation of the gas procurement portfolios, please explain why not.

Response:

Although gas portfolio amalgamation will benefit customers, as discussed in the response to BCUC IR 1.38.6, it is not expected to result in cost savings to the CMAE budget. While amalgamation of the gas portfolios will position the FEU to better optimize the gas supply and midstream portfolio over the long term, any benefit from that would flow back to customers through gas cost or midstream cost recovery charges and are unlikely to be material in the near to medium term.

Cost savings to the CMAE budget as a result of the amalgamation of the gas portfolios are not expected for a number of reasons. Since 2003, following the Utilities Strategies Project[10], the gas portfolios have been managed by a single team and consolidated CMAE budget. Costs included in the CMAE are largely labour and service related and are not expected to change in any material way as a result of the amalgamation of the gas portfolios. Where savings may be realized in the future involves simplifying contract negotiation, administration, and counterparty risk management. This simplification however is unlikely to result in significant savings and

[10] The Utilities Strategies Project was initiated in 2003 to restructure and integrate the management teams at then Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. into a single support team for all utility activities.

would unlikely be realized in the first years of the combined portfolios because there could be higher costs initially arising from the need to modify existing contracts or arrangements to accommodate a single portfolio. In any case, given that CMAE costs are recovered through gas charges, any savings that do materialize would flow automatically through to customers.

43.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.2.2, p. 147

O&M Labour and Benefit Increases for 2012 and 2013

Table 5.3-2: O&M Labour and Benefit Increases for 2012 and 2013[74]

($ thousands) Utility/Region	2012 Labour Inflation	2012 Benefits	Total for 2012	2013 Labour Inflation	2013 Benefits	Total for 2013
Mainland *	2,160	(127)	2,033	2,507	1,266	3,774
Vancouver Island	152	(649)	(497)	140	4	144
Whistler	17	4	21	4	3	6
Total	**2,329**	**(772)**	**1,557**	**2,651**	**1,273**	**3,924**

* Fort Nelson - Labour Inflation and Benefits is included in Mainland and allocated and allocated to Fort Nelson

43.1 The Benefits increases for 2012 and 2013 do not follow any standard relationship to the changes in Labour. Please provide more detail to explain the net change in Benefits presented in Table 5.3-2.

Response:

The tables below break down the benefit costs by company for 2012, and for 2013. Amounts shown are in $ thousands.

2012	Mainland	Vancouver Island	Whistler
Pension/OPEB - Current Service	2,133	33	4
Pension/OPEB - Past Service	(2,821)	(684)	-
Employee Wellness	151	(5)	(1)
Workers' Compensation Board	16	-	-
Medical Services Plan	33	(1)	-
Canada Pension Plan	61	(2)	-
Employment Insurance	25	(1)	-
Employee Savings Plan	44	-	-
Employee Share Purchase Plan	4	-	-
Employee Incentive Plan	227	11	1
Total Benefit Inflation	(127)	(649)	4

2013	Mainland	Vancouver Island	Whistler
Pension/OPEB - Current Service	279	20	1
Pension/OPEB - Past Service	(489)	(92)	-
Employee Wellness	462	27	1
Workers' Compensation Board	45	2	-
Medical Services Plan	106	6	-
Canada Pension Plan	183	10	-
Employment Insurance	76	4	-
Employee Savings Plan	125	8	-
Employee Share Purchase Plan	14	1	-
Employee Incentive Plan	466	17	1
Total Benefit Inflation	1,266	4	3

The Tables above provide a detailed breakdown of the incremental employee benefit costs for 2012 and 2013 for Mainland, Vancouver Island and Whistler.

- Pension/OPEB - as explained on page 150 of the Application (Exhibit B-1), incremental changes to Pension and OPEB, both current service and past service, are based upon actuarial estimates provided by the Companies' actuaries, Towers Watson and Morneau Sobeco.
- Employee Wellness is a combination of Extended Health, Dental, Group Life and Long Term Disability. Through an employee Choices program, employees have the flexibility of tailoring the Companies' contribution to Employee Wellness in a fashion that suits their individual/family needs.
- Workers' Compensation Board – are based on rates prescribed by the Provincial Government of BC.
- Medical Services Plan – are based on rates prescribed by the Provincial Government of BC.
- Canada Pension Plan – are based on rates prescribed by the Federal Government of Canada.
- Employment Insurance – are based on rates prescribed by the Federal Government of Canada.
- Employee Savings Plan – a corporate benefit that equates to 3 percent of base salary for eligible employees.

- Employee Share Purchase Plan – a corporate benefit whereby eligible employees can contribute up to 10 percent of their annual salary per calendar year to purchase Fortis Shares at 90 percent of the Average Market Price.
- Employee Incentive Plan – benefits are part of the Companies' Total Rewards framework as explained on page 146 of the Application (Exhibit B-1).

44.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.2.3, p. 150-151

Codes and Regulations

"Codes and Regulations funding requirements are driven by the Companies' need to comply with existing codes and regulations as well as anticipated new or changed codes and regulations."

44.1 Please confirm there have been no changes to codes and regulations since January 2010, or expected up to December 2013, that have resulted or will result in less cost for the FEU Companies.

Response:

As a general rule the need to comply with changing codes and regulations imposes increasing cost pressure over time. However, sometimes there is a one-time cost to achieve compliance, and other items are of a cyclical nature that can reduce costs. Any such one-time or cyclical cost reductions have been included in the Application. The removal of such costs when they are no longer required include, for example:

- 2011 Distribution - Single Point of Failure Analysis ($200 thousand)
- 2011 Distribution - Electronic Station Charts Study ($50 thousand)
- 2012 Distribution - Seismic Risk Assessment ($145 thousand)
- 2012 Transmission - CSA Z662 - Annex A Work Completed ($250 thousand)

There have been no changes to codes and regulations between January 2010 and June 2011 that have resulted or will result in less ongoing cost for the FEU. At this time, the FEU are not aware of any changes to codes or regulations that will result in less cost between June 2011 and December 2013. A new revision of CSA Z662 is expected to be published later in 2011, but its impact on costs is unknown at this time.

45.0 Reference: Summary of Forecast 2012 & 2013 Operating Costs (Departmental Overview)

Exhibit B-1, Application, Part 5.3.3, pp. 156-157

Operating Costs

45.1 In the same format as Table 5.3-6 provide schedules showing the 2006-2010 Approved, Actual and Variance (Approved – Actual) operating costs by department for FEI, FEVI, FEW and Fort Nelson. Also provide the tables in fully functional electronic format.

Response:

Actual O&M 2006 to 2010

Table 5.3-6 in the Application (Exhibit B-1) provides the O&M changes for each of 2012 and 2013 forecast by the five O&M cost drivers. 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 time period 2006 through 2010. However, in Appendix D-2 of the Application (Exhibit B-1) the FEU have provided actual O&M for the years 2006 through 2010 by activity view which provides a greater level of detail for reporting than the departmental view that was provided in Tables 5.3-6 through 5.3-13. These same schedules for 2012 and 2013 are included in the financial schedules for each of the utilities in Section 7 of the Application (Exhibit B-1). The spreadsheets from Appendix D-2 are included in fully functional electronic format as Attachment 45.1.

Approved O&M 2006 to 2010

The approved O&M for the years 2006 through 2009 was determined by formula for FEI and FEVI. Although, in the 2010-2011 RRAs, FEI and FEVI did allocate the approved formula-driven O&M to each of the departments for 2006 through 2009, the method by which this was achieved was to start with the 2003 base O&M, restate that base by the current departmental structure and then inflate each department's base by the formula for each of the years. To recreate this, given the changes in departments in the intervening period, would be a significant undertaking and, in the FEU's opinion, would be of very limited value since the amounts would still only be an allocation of a formula.

For 2010, FEI and FEVI provided the changes in forecast O&M by cost driver in their 2010-2011 RRAs and have reproduced the relevant tables below. Note that these figures do not equal the final approved O&M, since the NSAs for each of the utilities reduced this forecast O&M by $3.126 million and $0.874 million respectively for 2010 from what is shown in these tables.

FEI 2010: Proposed Department O&M Changes by Cost Driver

Department	*2009 Projection*	*2010 Inter Department Transfers*	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	*2010 Forecast*
Distribution	*36,952*	*150*	2,440	-	1,682	-	-	(142)	(28)	3,952	*41,054*
Gas Supply and Transmission	*16,946*	*(83)*	546	-	486	-	298	(1,679)	803	454	*17,317*
Marketing and Development	*66,557*	*(363)*	220	402	1,000	4,026	-	(1,616)	2,023	6,055	*72,249*
Business and Information Technology Services	*39,108*	*60*	1,680	-	1,277	-	243	1,246	3,653	8,099	*47,267*
Human Resources and Operations Governance	*8,445*	*236*	541	190	852	-	276	(26)	216	2,049	*10,730*
Finance and Regulatory Affairs	*9,585*	-	320	-	-	300	-	(199)	(365)	57	*9,642*
President	*17,486*	-	(2,931)	-	-	200	-	(725)	(2,699)	(6,155)	*11,331*
Total ($thousands)	*195,079*	-	2,816	592	5,297	4,526	817	(3,141)	3,604	14,511	*209,590*

FEVI 2010: Proposed Department O&M Changes by Cost Driver

Department	*2009 Projection*	*2010 Inter Department Transfers*	Labour Inflation and Benefits	Code and Regulations	Accounting Changes	Mt Hayes LNG	Service Enhancements	Total Incremental	*2010 Forecast*
Distribution	*5,500*	*(123)*	284	(95)	78	-	(18)	126	*5,626*
Gas Supply and Transmission	*5,549*	-	204	11	(1,219)	254	50	(700)	*4,850*
Marketing and Development	*6,886*	*(109)*	13	-	(476)	-	367	(205)	*6,681*
Business and Information Technology Services	*2,653*	*12*	23	45	-	-	(96)	(16)	*2,637*
Human Resources and Operations Governance	-	-	-	-	-	-	-	-	-
Finance and Regulatory Affairs	*325*	-	-	-	90	-	(35)	56	*381*
President and CEO	*7,863*	*220*	147	-	-	-	4,613	4,980	*12,843*
Total ($thousands)	*28,776*	-	671	(39)	(1,527)	254	4,882	4,241	*33,017*

Variance in O&M 2006 to 2010

The FEU are unable to provide this information by cost driver due to the factors discussed above. The FEU note that the 2010 actual vs. 2010 approved O&M amounts by department have been included by department in Section 5 of the Application.

46.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.4, pp. 158-159

Employees – Historical by category

46.1 Please provide a working spreadsheet which re-casts the data in Table 5.3-14 and includes 2009 Actual, for the Amalgamated companies, and separates the total employee FTE into Capital, Deferred – EEC, Deferred – Other, Thermal Energy Services, CMAE, and Operating & Maintenance. If any additional categories are required for clarity, such as NGV and Biomethane, please add and identify them. Separation by company is not required. Breakout by affiliation is not required.

Response:

Please refer to Attachment 46.1 for the FEU Total Employees by Category for 2009-2013. Please note that this table reflects full time equivalent employees as at December 31st for each year.

47.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.4, pp. 158-159

Employee/FTE – O&M by division

Operating & Maintenance Employees/FTE												
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13
		2009 **Actual**	2010 **Approved**	2010 Actual	2011 **Approved**	2011 Projected	2012 **Forecast**	2013 **Forecast**	Add in 2010 C4 - C3	Add in 2011 C6 - C4	Add in 2012 C8 - C6	Add in 2013 C9 - C8
Total O&M Employees/FTE												
	Mainland (excluding CMAE)		975	1,009	1,003	999	1,321	1,321				
	Vancouver Island		72	77	82	79	81	82				
	Whistler		3	1	2	2	2	2				
	Fort Nelson		3	3	3	3	3	3				
p. 159	**Total**	**0**	**1,053**	**1,090**	**1,090**	**1,083**	**1,407**	**1,408**		37	317	1
Sub-total By Group												
Distribution			407	412	**423**	413	**425**	**432**		16	**2**	**7**
Transmission			75	81	**80**	81	**86**	**88**		5	**6**	**2**
ES & RD excluding CMAE			21	20	**21**	23	**24**	**25**		0	**3**	**1**
Customer Services			29	31	**29**	31	**310**	**296**		0	281	(14)
Energy Solutions and External Relations			88	96	**92**	100	**107**	**107**		4	**15**	0
Information Technology			58	57	**58**	60	**66**	**67**		0	**8**	1
Operations Engineering			119	109	**126**	122	**129**	**129**		7	**3**	0
Operations Support			86	76	**88**	83	**89**	**92**		2	1	3
Facilities			17	14	**16**	17	**18**	**18**		(1)	2	0
Human Resources			71	116	**72**	70	**71**	**72**		1	(1)	1
Environment, Health & Safety			12	12	**14**	14	**14**	**14**		2	0	0
Finance & Regulatory Affairs			69	68	**69**	69	**69**	**69**		0	0	0
Corporate/President			2	1	**2**	1	**1**	**1**		0	(1)	0
pp. 165-262	**Total**	**0**	**1,054**	**1,093**	**1,090**	**1,084**	**1,409**	**1,410**	0	36	319	1
								Excluding Customer Services	**0**	**36**	**38**	**15**
								Codes & Regulations			**4**	**3**
								Customer/Stakeholer Expectations			**23**	**0**
								Service Standards & Reliability			**32**	**13**
								Additions as detailed in the Section 5 write-ups			**59**	**16**

47.1 Please provide the data for 2009 Actual (column 3).

Response:

Please refer to BCUC IR 1.47.2.

47.2 Please comment on the difference in the proposed staff additions in this schedule and the total number of proposed staff additions in the Codes & Regulations, Customer/Stakeholder Expectations, and Service Standards & Reliability groupings of Part 5 of the Application.

Response:

The FEU have adjusted the schedule above to reflect the Total Employees by Department (instead of O&M Employees by Department) in order to reconcile the proposed staff additions in this schedule against the total number of proposed staff additions in the Demographics, Codes & Regulations, Customer/Stakeholder Expectations, and Service Standards and Reliability groupings in Section 5 of the Application (Exhibit B-1).

Total Employees/FTE

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13
Total Employees/FTE		2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast	C4-C3	C6 - C4	C8 - C6	C9 - C8
	Mainland	1,161	1,294	1,316	1,311	1,692	1,701	1,701	134	17	390	(0)
	Vancouver Island	100	111	107	122	124	123	124	10	11	1	1
	Whistler	2	3	1	2	2	2	2	1	(1)	0	0
	Fort Nelson	3	3	3	3	3	3	3	0	0	0	0
	Total	1,266	1,411	1,427	1,438	1,821	1,828	1,829	145	27	391	1
Sub-total by Group for all employees (both capital and O&M)												
Distribution		556	622	595	624	658	661	670	65	2	37	9
Transmission		67	75	81	85	86	92	94	8	10	7	2
ES&RD excluding CMAE		39	42	40	42	45	46	47	3	0	4	1
Customer Service		29	36	37	36	367	325	309	7	0	289	(16)
Energy Solutions & External Relations		82	98	111	103	118	125	125	16	5	22	0
Information Technology		54	64	67	64	66	75	76	10	0	11	1
Operations Engineering		141	166	160	174	178	193	193	24	8	19	0
Operations Support		119	138	124	138	133	139	142	19	0	1	3
Facilities		11	17	14	16	17	18	18	6	(1)	2	0
Human Resources		92	71	116	72	70	71	72	(21)	1	(0)	1
Environment, Health & Safety		10	12	12	14	14	14	14	2	2	0	0
Finance & Regulatory Affairs		64	69	68	69	69	69	69	5	0	0	0
Corporate/President		2	2	1	2	1	1	1	0	0	(1)	0
Total		1,266	1,411	1,427	1,438	1,821	1,828	1,829	145	27	391	1
Less: CMAE		19	21	20	21	22	22	22	2	0	1	0
Less: Customer Service		29	36	37	36	367	325	309	7	0	289	(16)
Total Excluding CMAE & Customer Service		1,218	1,354	1,370	1,381	1,432	1,482	1,499	136	27	101	17
Demographics											2	1
Codes & Regulations											2	5
Customer/Stakeholder Expectation											23	0
Service Standards & Reliability											33	11
Updated Additions as detailed in the Section 5 write up											60	17
Difference											41	0

To explain the difference, we have created a table and accompanying notes that reflect the 2012 and 2013 employee additions by cost driver, including other employee additions that were not specifically referenced in Section 5 of the Application.

Department	Demographics	Codes & Regulation	Customer /Stakeholder Expectation	Service Standards & Reliability	Other employee additions	2012 Additions (2012 Forecast vs 2011 Approved)	Demographics	Codes & Regulation	Customer /Stakeholder Expectation	Service Standards & Reliability	2013 Additions (2013 vs 2012 Forecast)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Distribution	2			17	18	37	1	3		5	9
Transmission				4	3	7				2	2
ES&RD excluding CMAE				1	2	3				1	1
Customer Service						0					0
Energy Solutions & External Relations			22			22					0
Information Technology				9	2	11				1	1
Operations Engineering		2			17	19					0
Operations Support			1			1		2		1	3
Facilities				2		2					0
Human Resources						0				1	1
Environment, Health & Safety						0					0
Finance & Regulatory Affairs						0					0
Corporate/President					(1)	(1)					0
Total	**2**	**2**	**23**	**33**	**41**	**101**	**1**	**5**	**0**	**11**	**17**

Column 6 indicates 41 employee additions in 2012 that were either discussed without indicating the cost driver grouping or not mentioned in the O&M section of the Application. These employee additions of 41 are discussed by department below:

- In Distribution, there were 20 dependant contractors excluded in the 2011 approved that converted to regular employees in 2011 projection and 12 employee additions in the Operations Centre that were partially offset by the elimination of 14 IBEW positions, resulting in net employee additions of 18. These employees work mostly on capital related activities and have minimal impact on O&M. For further explanation, please see the response to BCUC IR 1.48.2.

- Transmission added 1 new employee in 2011 above what was approved for that year that is required to help ensure quality and code compliance for the Coastal Transmission System. In 2012, a further 2 employees are required to support ongoing measurement control requirements and for the completion of work associated with preventative maintenance plans.

- Energy Supply and Resource Development added 2 new employees in 2011 above what was approved for that year as business development specialists to help the Resource Development group as discussed on page 188 of the Application.

- Information Technology in-sourced 1 database analyst position for internal database support that is completely offset through reduction of external consulting dollars. Furthermore, IT added 1 technical resource in the Enterprise Application Support & Delivery team for SAP ECC (Financials, HR, Supply Chain, Preventive Maintenance, Work Management) based on the need to support additional technologies we have acquired over time that are used to support business operations. As stated in the

Application, page 222, Information Technology continues to maintain an effective staffing level commensurate with the broader organization in 2011 while balancing the mix of internal versus external sources.

- Operations Engineering is forecasting an increase in employees to address new and existing compliance requirements and to respond to anticipated capital program increases related to the LTSP (please refer to page 229 of the Application), however, the specific number of 17 additional employee additions in 2012 was not referenced in the Application.

- In Corporate, the reduction of 1 employee was due to the retirement of the FEU's past president as discussed on page 263 of the Application.

48.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, pp. 171-178

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

($ Thousands)	**Service Standards & Reliability**						
	Requested/ Approved 2010	Requested/ Approved 2011	Requested 2012	Requested 2013	New FTE 2012	New FTE 2013	
Distribution							
Service Enhancement cost drivers	(28)	351					
Field Service Delivery unit costs			416	272			Ref: Unit cost increases
Meter battery upgrades			160				Ref: Unit cost increases
Bridge crossing repairs			160				Ref: Unit cost increases
Station transition repairs			100				Ref: Unit cost increases
Leak repairs			110				Ref: Unit cost increases
Line locates			125				Ref: Unit cost increases
Valve inspections			200				Ref: Unit cost increases
Gas odour calls			200				Ref: Unit cost increases
NGV asset mgmt			225	115			Ref: NGV
Biomethane asset mgmt			23	68			Ref: Biomethane
Asset Mgmt - Analyst (1)/Asst (1)			160		2		Ref: NGV and Biomethane
Asset Mgmt - Assistants (2)				140		2	Ref: NGV and Biomethane
Ops. Centre - Planners (3) / OSRs (3)			448		6		
Ops. Centre - Planners (3)				58		3	
Reporting Analyst (1)			90		1		
IT Support Analyst (1)			70		1		
GIS IT licencing & staff			200		1		
System sustainment assessments			405	455			
System sustainment assessment staff			150		3		Engineer (1) & Analysts (2)
System sustainment assessment staff				45		1	Analyst (1)
System sustainment assessment staff			100		2		Planners (2)
Non-labour inflation			256	228			
Line Heater fuel			(590)				
First Response Standby			(440)				
Other			(48)	(138)			
Field Service Delivery unit costs			353	72			Ref: Vancouver Island
Bay St Bridge Crossing Repairs				330			Ref: Vancouver Island
Decling post-conversion costs			(42)	(6)			Ref: Whistler
Minor changes			(4)	7			Ref: Fort Nelson
Distribution	(28)	351	2,827	1,646	**16**	**6**	
	(28)	351	2,827	1,646			

48.1 Please confirm the table above represents the Distribution O&M budget and staff changes requested for 2010 through 2013 related to Service Standards & Reliability. If this table is incorrect, please provide the correct table.

Response:

The table in the preamble for this question above is correct as to dollar amounts, however, there were two minor errors related to headcount. We have included the correct tables below for 2012 and 2013.

For 2012:

			$000s	Description	New FTE in 2012
2012	FEI	$	90	Asset management analyst	1
		$	70	Asset management assistant	1
		$	200	*Mobile GIS license plus IT FTE***	
		$	160	Battery upgrades for industrial meters	
		$	225	NGV assets	
		$	23	Biomethane assets	
		$	110	Bridge crossing repairs	
		$	100	Station transition repairs	
		$	110	Leak repairs	
		$	125	Line locates	
		$	200	Valve inspections	
		$	(590)	Operations including line heater fuel	
		$	200	Gas odour calls	
		$	(440)	First response standby	
		$	1,130	Meter to cash costs	
		$	(1,120)	Meter to cash revenues	
		$	158	Field Service Delivery - Misc (stations, patrol,etc)	
		$	90	Distribution reporting analyst	1
		$	70	Process support analyst	1
		$	448	Operations center (regular operations)	6
		$	256	Vehicle & other non-labour inflation	
		$	45	Asset management analyst	1
		$	60	Asset management engineer	1
		$	45	Asset management analyst (system sustainment)	1
		$	1,000	System sustainment assessments	
		$	100	Operations center (system sustainment)	4
		$	(145)	Seismic risk analysis	
		$	(200)	Single point of failure analysis	
		$	**2,520**		**17**
2012	**FEVI**	$	353	Field Service Delivery (FEVI)	
		$	**353**		**0**
2012	**FEW**	$	18	Non-labour inflation	
		$	(60)	Management reduction	
		$	**(42)**		**0**
2012	**FEI FTN**	$	(4)	Minor changes	
		$	**(4)**		
		$	**2,827**		**17**

For 2013:

		$000s		Description	New FTE in 2013
2013	FEI	$	70	Asset management assistant	1
		$	70	Asset management assistant	1
		$	68	Biomethane assets	
		$	115	NGV assets	
		$	89	Operations including line heater fuel	
		$	58	Operations center (regular operations)	3
		$	228	Vehicle & non-labour inflation	
		$	45	Asset management analyst	
		$	500	System sustainment assessments	
		$	**1,243**		**5**
2013	FEVI	$	40	Delivery cost centers	
		$	330	Major Bridge repair	
		$	32	Vehicle & non-labour inflation	
		$	**402**		
2013	FEW	$	6	Vehicle & other	
		$	(12)	Industrial meter maintenance	
		$	**(6)**		
2013	FEI FTN	$	7	Minor changes	
		$	**7**		
		$	**1,646**		**5**

There was an error on page 176 of the Application (Exhibit B-1), third paragraph,

> *"Asset Management will require the following additional resources: one engineer and two analysts in 2012 ($150 thousand), and one additional analyst in 2013 ($45 thousand)".*

The corrected sentence should read,

> "*Asset Management will require the following additional resources: one engineer and two analysts in 2012 ($150 thousand). One engineer and one analyst will be hired at the start of the 2012. The second analyst will be hired in mid-2012. In 2013, an incremental $45 thousand is required to support this resource".*

This headcount is included in 2012.

48.2 Please explain the difference between the proposed O&M staff additions for 2012 and 2013 for Distribution's Service Standards & Reliability and Codes and

Regulations categories as presented in the Application detail and the numbers for O&M in Table 5.3-16 on page 165.

Response:

A portion of Table 5.3-16 from page 165 of the Application (Exhibit B-1), (Total Distribution Employees) has been reproduced below with two additional columns which detail the employee changes from 2011 Approved to 2012 and from 2012 to 2013. Please also refer to the response in BCUC IR 1.48.1 which correctly summarized the headcount impacts from the Service Standards & Reliability category.

Table 5.3-16 Distribution - Total Employees

Utility Region	2011 Approved	2011 Projection	2012 Forecast	2012 Forecast Less 2011 Approved	2013 Forecast	2013 Forecast less 2012 Forecast
Mainland	539	571	577	38	586	9
Vancouver Island	80	82	79	-1	79	0
Whistler	2	2	2	0	2	0
Ft.Nelson	3	3	3	0	3	0
Total	624	658	661	37	670	9
Changes:						
Additions - Service Standards & Reliability				17		5
Additions - Codes & Regulations				0		3
Additions - Demographics				2		1
Additions - Dependent Contractors Converted to IBEW				20		0
Additions - Operations Centre (various)				12		0
Deletions - Vancouver Island - IBEW				-3		0
Deletions - Lower Mainland -IBEW				-11		0
Net Change				37		9

The employee additions for the Service Standards & Reliability category are summarized in the response to BCUC IR 1.48.1 and are 17 for 2012 and 5 for 2013.

The employee additions for the Codes and Regulations category are 3 in 2013. These represent Asset Compliance Manager roles as described on page 172 in the Application.

The employee additions for the Demographics category are referenced on page 173.

The employee additions in 2011 related to Dependant Contractors are referenced in the footnote on page 159.

The employee additions in 2010/2011 related to the Operations Department (operations office positions) are various changes primarily related to capital work and include additional customer appointment representatives, impacts of a departmental restructuring, and planner additions for complex capital activities including third party work. These employees were not discussed in the O&M section since they are primarily capital.

Partially offsetting the additions in 2012 were the elimination of 14 positions (vacant field positions in the Lower Mainland and Vancouver Island) which were no longer necessary due to changes in crew numbers and configurations and ability to use contractors for peak shaving for capital activities. These position reductions were not discussed in the O&M section.

49.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.2, pp. 166-167

Distribution – Consultants and Contractors

"In 2010 and 2011, the contractor/consultant employee equivalent embedded in Distribution O&M budgets is approximately 45 employees."

49.1 Please provide the Distribution O&M budget for 2012 and 2013 for these contractors and consultants and explain if the cost is for labour and expenses only or if it includes equipment.

Response:

The contractor/consultant budgets embedded in the Distribution O&M are as follows:

2012:

FEI	$3,840,255
FEVI	$508,741
Total	$4,348,996

2013:

FEI	$4,635,578
FEVI	$838,198
Total	$5,473,776

The cost is for labour, vehicles, expenses, equipment and materials used by contractors/consultants in the completion of O&M activities. Generally speaking, the non-labour expenses are included in an overall inclusive rate charged by the contractor. For example, the leak survey contract has rates that provide for a per kilometre rate charged by the contractor for each kilometre of pipe surveyed. This rate is inclusive of labour, vehicles, expenses, tools and equipment and any materials used by the contractor in completion of the leak survey. Other contracts/consultants, such as long term system sustainment analysis, are expected to be primarily for salaries.

50.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 172

Distribution – ROW signage colour change

"ANSI standard Z535.1 requires natural gas markers to be yellow, instead of orange. FEU has implemented this change for distribution pressure mains and it is necessary to extend this program to pipelines in order to achieve compliance."

50.1 Please provide the cost of the colour change for the distribution pressure mains completed, and the number of kilometers of mains involved. Please provide the number of kilometers of pipelines involved in the 2012 program. Please explain the cost differential for the 2012 program.

Response:

The FEU have completed the installation of code compliant line markers for distribution pressure mains. The work was completed over a number of years and performed as part of new or replacement main installations which are capital activities or during normal line patrol maintenance activities. As a result, the cost for distribution mains was not tracked separately; therefore, cost or length details are not available.

Starting in 2012 and extending for approximately five years at a cost of $120 thousand per year, a program will be initiated to bring Intermediate Pressure and Transmission Pressure pipeline markers into compliance with the requirements of ANSI Z535.1; this program is not required on Vancouver Island as those markers are already compliant with Z535.1. Estimates for the programs initiated in 2012 and including 2013 are based on the number of kilometres of pipeline and an estimated number of markers per kilometre. The 2012 and 2013 funding request is based on approximately 700 kilometres of pipeline per year for five years and $170 per kilometre, 6 markers per kilometre and approximately $25 per marker. In addition, in instances where signs mark road crossings, the cost per kilometre is expected to be higher and where the pipeline is primarily in an open field the cost per kilometre is expected to be lower. Overall the program cost per unit is expected to be in the range of $25-$30 per marker.

50.2 Please provide the reference in the Application to the reduction in O&M for the completed work of changing the markers for the distribution pressure mains.

Response:

As discussed in BCUC IR 1.50.1, replacement of line markers for distribution mains was captured under capital main installation activities and routine corrective O&M and is not separately tracked. Going forward, new line markers will continue to be installed as part of capital main installation activities and routine O&M line marker replacements (e.g. replacing markers that are damaged, destroyed or removed by others). There is an ongoing need for this type of base O&M funding for line marker post replacement and first time new line markers are included in main capital project costs. As a result, there will be no reduction in O&M associated with routine replacement of line markers on distribution mains.

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). There will be no reduction in this incremental O&M request until 2017 when the bulk of replacements on these systems will be completed

50.3 Please explain why the colour change would not be done as the ROW signage required normal replacement. If the ANSI standard requires a more immediate change, please provide the reference from the ANSI standard.

Response:

Line markers typically last for a number of years between replacements (greater than five years). 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. Also, not all markers on a section of pipeline typically require replacement at the same time; this would result in a 'hit and miss' upgrade of the colours and further result in several years to complete the program. While markers replaced as a normal part of Right of Way ("ROW") maintenance will be upgraded to the new colour, the $120 thousand requested annually commencing in 2012 (please refer to the Application, page 172, Exhibit B-1) will enable a planned approach to upgrading the entire system, line section by line section. This program will be coordinated with other ROW maintenance activities to maximize efficiencies as well as ensuring that no markers on a line section are missed.

50.4 Please explain if the name change from Terasen to Fortis is also required on the ROW signage.

Response:

While the new line markers will include the FortisBC name, this is not required. The 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.

51.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 172

Distribution – Additional Asset Compliance Managers

"Three additional Asset Compliance Managers are requested in order to provide one manager per operational zone and facilitate effective monitoring of field work activities, particularly in light of the number of new employees, employees new in positions and contractors performing significant portions of new main and service installations. It is neither feasible nor practical to have two Asset Compliance Managers cover the entire five gas distribution service areas and the full scope of activities including new installations, routine operations and maintenance, emergencies, customer service work, design, and planning."

51.1 Please explain the "quality audit" program, including the process for selecting "activity" to audit, the number of audits, the reporting done, and the follow-up process on "failed" audits.

Response:

The quality audit program reviews those activities that affect the reliability of the asset, and as such all related field and office activities are subject to review. Initially audits will be based on random selection, maintenance results or anecdotal information received from Operations personnel. As experience is gained and the results are analyzed, future audits will be targeted at problem areas while continuing to maintain random samplings in areas of lesser concern.

Activities that fail to meet requirements will be corrected on site and a report issued to the local Operating Manager for review and follow up. The results of all inspections will be stored in a centralized repository and the results of the audits will be analyzed and included in the annual report on asset health provided to the FEU management.

51.2 Please describe the five operational zones, and explain if the work in each of the five zones is equal.

Response:

The five operational zones for Distribution are:

1. Metro Vancouver (including Vancouver, Burnaby, New Westminster, Richmond, New Westminster, Coquitlam);
2. Fraser Valley (including Delta, Surrey, Langley, Abbotsford, Chilliwack, Pitt Meadows, Maple Ridge, Mission);
3. Interior South (including Kelowna, Vernon, Penticton, Cranbrook, Trail);
4. Interior North (including Kamloops, Prince George); and
5. Vancouver Island (including Victoria, Nanaimo, Courtenay).

The type of work is consistent from zone to zone; however, the variation in the number of work activities in each zone is considerable. This is due to factors including: number/type of customers/meters, number of gas emergencies and odour calls, operational and maintenance activities, installation activities, etc. Another significant differentiating factor is the size (area) of each zone and the distance between regional and satellite service areas. Due to volume of work activity in each zone and the significant travel requirements, an Asset Compliance Manager per zone is required to ensure effective monitoring of field activities.

Please refer to BCUC IR 1.131.1 for customer, employee and work activity details on regional offices/musters.

51.3 Please explain the current process for monitoring field work activities, including why the staff currently monitoring and approving the field work activities can not continue to perform that work as well as assess the "quality" of the work completed.

Response:

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 audits, reviews, and evaluations."

This is new, incremental work and resources must be made available to complete the work in order to meet code. Additionally, having audits completed by the Asset Compliance Managers, who do not report to local management, provides the arms length relationship and minimizes potential conflict of interest.

These management resources are required to meet code requirements and ensure the integrity of the gas assets.

51.4 Please provide a percentage separation of the work of the Compliance Managers between installations (capital), routine and emergency (O&M), and customer service work related to EEC (deferred), Thermal, NGV and Biomethane (segregated). Please confirm the requested funding relates only to the O&M work category.

Response:

The Asset Compliance Managers will focus on capital (installation) activities and O&M (meter exchange, meter maintenance, emergencies, etc.). The capital and O&M split is anticipated to be 50/50. The requested funding only relates to O&M. At this time the Asset Compliance Managers are focussed on establishing the program for routine gas operations and are not auditing the activities associated with Thermal Energy, NGV or Biomethane assets. However, in the future as the Thermal Energy, NGV and Biomethane activity increases, there may be a requirement for Asset Compliance Managers to conduct audits on these assets as well. The work of the Compliance Managers is not related to EEC.

52.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 172

Distribution – Standardization of locks and security devices

"FEU must standardize locks and security devices at field facilities to meet code requirements and maintain adequate security measures (CSA Z662 and CSA Z246.1) to ensure only authorized personnel have the appropriate access to facilities and operating equipment. This is particularly important as the amalgamation of different companies and operating areas (the last one being Vancouver Island in 2006) has resulted in different keys and locks being used in different areas across the Province, limiting the ability to effectively move personnel and provide access to facilities as the work requires. FEU will implement a lock standardization program. The program plans to complete 50 percent of the lock upgrade and replacements in 2013 and complete the remainder of the program in 2014."

52.1 Please explain why standardization is required "to ensure only authorized personnel have appropriate access to facilities and operating equipment"? Are these facilities and operating equipment not currently secured?

Response:

All FEU field facilities are secured; however, changes are required to provide a higher level of security protection, specifically with respect to the ongoing control of keys and access.

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.

The FEU must upgrade field facilities to install a higher level of security and more limited access to ensure only authorized personnel are equipped to operate our facilities for the following reasons:

1. Changes in code requirements including CSA 662 and CSA Z246.1 require the operator to ensure adequate security protection of facilities;
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;
6. Changes in public expectations mean that the FEU have an obligation to ensure adequate security of field facilities; and
7. Changes in the external environment have identified natural gas facilities as likely targets for domestic and international terrorists.

52.2 Please explain why adherence to CSA Z662 and CSA Z246.1 is being addressed now and was not done in 2006 to 2009 since it was "particularly important" following "the amalgamation of different companies and operating areas … the last one being Vancouver Island in 2006."

Response:

CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems, was published in 2009 and the Oil and Gas Commission advised of their intent to adopt the regulation in September 2009. This increased the priority of addressing the security of the gas delivery facilities. Subsequent security vulnerability assessments of gas delivery facilities have also identified key control as an area where improvement is required.

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.

53.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 174

Distribution – Additional Planners and OSRs

"In 2012, three Planners and three Operational Support Representatives ("OSRs") in the Closing and System Survey sub-group of the Distribution group are required. In 2013, three additional Planners, including a work-leader to supervise a large planning group, are required. The Planners, who typically meet on construction sites with homeowners, developers and municipalities to design and cost estimate gas system infrastructure, ***are required primarily for capital activities****; however, they also engage in training, supervision and reviews of municipal project plans which are classified as O&M activities."* [Emphasis added]

53.1 Please provide the percentage of time spent by the planners, who are required primarily for capital activities, on O&M activities. Please confirm if the $506,000 requested is the full cost, on an annual basis, for these nine additional FTE, or is only for the O&M activities. If the 2013 amount does not cover the full annual cost, please provide the difference.

Response:

The percentage of time typically spent by the Planners on O&M activities (training, customer inquiries, municipal reviews, etc.) is 20 percent. Included with the Planner work group are Planning Work Leaders which are typically 100 percent O&M (primarily supervision activities). The three new OSRs in Closing and System Survey are also classified as 100 percent O&M.

On page 174 in the Application (Exhibit B-1), we incorrectly stated that the Planning Work Leader was one of the three Planners in 2013. The correct statement is that the Planning Work Leader is one of the three Planners identified in 2012.

The $506,000 requested ($448,000 in 2012 and $58,000 in 2013) is the O&M portion of the nine additional positions only. The $448,000 in 2012 is for 3 OSRs and1 Planning Work Leader (all four positions 100 percent O&M), together with 2 Planners classified as 20 percent O&M plus non labour expenses. The $58,000 in 2013 is for 3 Planners classified as 20 percent O&M plus non-labour expenses.

The Capital portion for the six additional headcount in 2012 is $124,000 and for the three additions in 2013 is $185,000.

The Planners typically work on Capital activities (company and customer driven) requiring significant interaction and coordination with customers, developers and municipalities including complex services, new mains, system improvements, hazard mitigation, alterations and various other capital projects. A portion of their Capital work is billable to third parties and accounted for in the Contributions in Aid of Construction ("CIAC") forecasts.

53.2 Please provide details of the total number of Planners and Operational Support Representatives as of the end of 2009, 2010, and projected for exist in 2011, 2012, and 2013 including these nine. Please provide the average cost per FTE in each year, 2009 through 2013.

Response:

The following tables provide the information requested.

		FTE's				
Cost Centre / Department		2009	2010	2011	2012	2013
CC 2095	**Closing & System Survey**					
	OSR's	17	17	18	21	21
CC 2101	**Planning**					
	OSR's			1	1	1
	Planners/Workleaders	35	37	36	39	42
Total		**52**	**54**	**55**	**61**	**64**

	Avg. Cost per FTE (O&M + Capital)				
	2009	2010	2011	2012	2013
Cost Centre / Department					
CC 2095 - Closing & System Survey					
OSR's	$ 55,392	$ 64,921	$ 68,475	$ 74,423	$ 78,004
CC 2101 - Planning					
Planners	$ 61,562	$ 69,172	$ 77,072	$ 79,999	$ 82,280
Planning Workleaders	$ 84,091	$ 94,994	$ 105,846	$ 108,900	$ 114,795

Operations Support Representatives (OSRs), Planners and Planning Workleaders are union personnel and salary rates are set through negotiated contracts with the COPE union. The usual contractual year over year increase for OSRs, Planners and Workleaders is a cost of living inflationary increase together with a step increase which recognizes another year of experience, and potentially an Employee Incentive Plan (EIP) payment based on corporate and personal results. Employees qualify for step increases early on in their positions until they reach a maximum number of years for their job grouping. In both cost centres above, there is a mix of employees entitled to the step increases and those already having reached the maximum of their job grouping. EIP payments vary by employee. The Planning group has also recently gone through several labour arbitration cases which have impacted average salaries and job levels.

53.3 How does the percentage increase of the nine new FTE compare to the percentage forecast customer additions in 2012 and 2013 compared to the base of forecast 2011?

Response:

The forecast customer additions in 2012 and 2013 (Table 4.2-2 page 77 in the Application, Exhibit B-1) are 5 percent higher in 2012 than 2011 and 4 percent higher in 2013 versus 2012. The FTE table in response to BCUC IR 1.53.2 summarizes the FTE headcount for the two departments and the 6 additional headcount in 2012 represents an 11 percent increase in 2012 versus 2011 and the 3 additional headcount in 2013 represents a 5 percent increase in 2013 versus 2012.

It is important to note that the increase in Operations Centre personnel is not directly linked to customer additions growth. The request for additional headcount is primarily being driven by an increase in other types of capital work including municipal and government projects which require relocation of gas mains and services, hazards mitigation work such as inactive services and stub services which need to be cut-off at the main, and meter-set upgrades.

54.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 175

Distribution – Costs driven by activity or unit cost changes

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 for battery upgrades for industrial meters, bridge crossing repairs, station transition repairs, leak repairs, line locates, valve inspections and gas odour calls.

54.1 For each of the items referenced above, please provide the comparable activity level or unit cost for each year from 2009 through 2013. Please explain why there are no changes referenced in the Application for these items in 2010, 2011 or 2013.

<u>Response:</u>

Please see Attachment 54.1, which summarizes the data requested for 2009-2013.

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.

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 $1,000 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.

The bridge crossing repairs were included in the 2010-2011 FEI RRA under "bridge and aerial crossing repairs" page 362 (2010 column). In 2013, there is a small incremental amount to 2012 which represents inflation.

The valve inspections were included in the 2010/-2011 FEI RRA under "Operations" page 364. The 2013 increment to the 2012 request is primarily labour/vehicle inflation.

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. Line locate activity is driven primarily by construction activity around larger size pipe together with BC One Call program awareness by excavators, municipalities and homeowners. The number of BC One Call tickets (request for gas location records) is increasing over time as the public becomes more aware of the service through public service advertising, the FEU gas awareness workshops, experience with hit lines, etc.

Gas odour calls are responded to as emergent calls and classified into five categories of calls (gas odour downstream of meter, gas odour upstream of meter, gas odour non-gas related, fire/explosion calls and carbon monoxide investigations). 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.

The 2013 funding request for the above activities is the same as in 2012 with the exception of the inclusion of inflation for the categories where labour is a significant component of the cost. The labour inflation is included in this Application (Exhibit B-1), Table 5.3-17, page 171 in the Labour Inflation and Benefits cost driver. The general comments with respect to labour inflation are located in section 5.3.2.2 page 146.

Two activities listed, battery upgrades for industrial meters and the station transition repairs, were excluded from the inflation adjustment in 2013 as they were essentially one-time, two-year programs involving a significant non labour component (materials, contractors).

55.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 176

Distribution – System Sustainment Assessments

*"In order to **support** the distribution system sustainment assessments, Asset Management will require the following additional resources: one engineer and two analysts in 2012 ($150 thousand), and one additional analyst in 2013 ($45 thousand). These resources are in addition to those identified to support Regular Operations and are required to ensure Asset Management has adequate skilled resources to ensure **capital investments** are appropriate, prioritized and administered effectively. In addition in 2012, the Operations Centre will require additional planners ($100 thousand) to manage increases in workload associated with the system sustainment assessments. The planners will work with engineers and analysts to plan, design and estimate changes such as **new installations**, alterations and **abandonments** to the gas distribution system. The Operations Centre requires adequate skilled resources to continue to plan, design and coordinate asset renewal projects and ensure **capital investments are appropriately coordinated.**"* [Emphasis added]

55.1 As these new requested positions are to support the existing processes, please provide the number of staff currently performing the distribution system sustainment assessments.

<u>Response:</u>

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").

Distribution has an ongoing program to assess asset renewal and replacements which is primarily reactive and involves two working groups within the Operations department. For example, when a municipality is planning to re-pave a road, the Planning group will determine if it is appropriate to replace or increase pipe capacity in coordination with the municipal works and make the appropriate recommendations to the Asset Management group. The number of employees currently performing these assessments in the Asset Management group is approximately three. The municipal project planning reviews conducted by the Planning department occur across the Province and vary substantially from municipality to municipality depending on level of infrastructure project activity. An estimate of the annual work effort Province wide for the Planning group is approximately three full-time equivalents. The municipal project reviews are typically within the context of a shorter-term perspective (0 to 5 years).

The detailed system sustainment assessments that look beyond five years are required in order to develop a proactive LTSP.

55.2 Please expand on the role of the Asset Management staff compared to the role of the Operations Engineering staff in the process of coordination of capital investment.

Response:

The System Integrity group within Operations Engineering provides services to Asset Management. Capital budgets are administered by Asset Management but the identification and prioritization of projects is influenced by the programs and information managed by Operations Engineering.

Operations Engineering provides additional services to Asset Management including project management and engineering. This work is typically in response to a request from Asset Management.

55.3 Please explain why the costs related to abandonments are not charged to the pool of funds charged for "salvage." Please confirm if the sustainment planning includes salvage of assets or assumes only abandonment.

Response:

The statement above that "costs related to abandonments are not charged to the pool of funds charged for salvage" is incorrect.

Planners in the Operations Centre charge their time to the job orders that they work on. Any of these job orders that are abandonment orders will therefore become part of the cost of an abandonment job, and will be part of the actual removal costs (negative salvage) that are incurred in any given year. These actual removal costs form the basis of the negative salvage estimates, and by this process the costs related to these planners are included in the negative salvage provision.

We have interpreted the second part of the question, whether sustainment planning includes salvage of assets or assumes only abandonment, to be a reference to whether positive salvage amounts are also considered in planning jobs. The FEU confirm that to the extent any salvage proceeds are received, they serve to reduce the costs incurred.

56.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.7, p. 177

Distribution – Vehicle and Other non-labour inflation

"Also included in the Service Standards and Reliability category is $256 thousand in 2012 and $228 thousand in 2013 for vehicle and other non-labour inflation such as contracts and materials."

56.1 Please explain why there was no comparable inflation increase requested in 2010 and 2011?

Response:

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.

57.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.5.11, p. 180

Transmission – Asset Management / Assessments

"an additional four employees are required in 2012, followed by an addition of two more employees in 2013. The four employees in 2012 are comprised of management and field staff for the increased asset management activities that the Companies expects as it completes detailed assessments of aging assets to determine the scope and timing of future asset renewals."

57.1 Please provide a summary of all employees, across all divisions and companies, performing "asset management" activities related to "detailed assessments of aging assets" and "the scope and timing of future asset renewals." For each division and/or company, please provide the appropriate measure of the amount of assets being reviewed, and how the number of FTE within an area (division; company) compares to those in the other areas in comparison to the assets being reviewed, separated by capital, O&M and deferred if required.

Response:

The FEU have interpreted BCUC IR 1.57.1 as a request for further details to better understand the Long Term Sustainment Plan (LTSP) given that the references to "*detailed assessments of aging assets*" and "*the scope and timing of future asset renewals*" made in the Application referred specifically to the LTSP and not to the Company's asset management practices in general.

The table that follows provides an estimate of the number of FTEs, and level of O&M and Capital included in the Application that is notionally attributable to the LTSP. The table is based on an estimate, because while the LTSP is an initiative to enhance existing processes used for the management of gas system assets, it is not a separate program with its own discreet resources and capital budget. With the exception of one technical FTE in FEVI, all other FTEs and associated O&M is with FEI. LTSP O&M costs associated with FEVI and FEW are allocated to those utilities via the shared services arrangement. For these reasons a company-by-company breakout was not completed.

The following table includes estimated O&M funding and associated FTEs, followed by Capital funding and associated FTEs attributable to the LTSP. Following the table is a discussion of each of these components.

Table BCUC IR1.57.1-1 - LTSP Summary
FEU Total

O&M Amounts in $ Thousands

Department	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Operations - Distribution	147	449	1,014	1,563
Operations - Transmission	375	373	1,491	2,305
Resource Development	-	-	74	155
Operations Engineering	-	481	242	377
Operations Support - Procurement	-	-	-	107
Total	**523**	**1,303**	**2,821**	**4,507**

FTEs - O&M

Department	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Operations - Distribution	0.50	0.50	3.00	3.50
Operations - Transmission	1.50	1.50	4.00	5.83
Resource Development	-	-	0.50	1.00
Operations Engineering	-	-	1.60	2.20
Operations Support - Procurement	-	-	-	1.00
Total	**2.00**	**2.00**	**9.10**	**13.53**

Capital Amounts in $ Thousands

Department	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Operations - Distribution	-	-	8,190	13,630
Operations - Transmission	-	-	14,378	17,753
Resource Development	-	-	-	-
Operations Engineering	-	-	-	-
Operations Support - Procurement	-	-	-	-
Total	**-**	**-**	**22,568**	**31,383**

FTEs - Capital

Department	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Operations - Distribution	-	-	3.00	4.00
Operations - Transmission	-	-	0.50	0.67
Resource Development	-	-	-	-
Operations Engineering	-	-	2.40	4.80
Operations Support - Procurement	-	-	-	-
Total	**-**	**-**	**5.90**	**9.47**

As described in the Application (Exhibit B-1), the FEU face an approaching wave of asset replacement requirements and increasing regulations to maintain the safety, reliability, and integrity of the transmission and distribution system. This challenge can be best met by continuing to improve the Companies' asset management practices. Significant advance planning is required so that appropriately detailed asset condition assessments can be completed to be able to estimate with confidence the probable time in the future when assets need to be refurbished or replaced. This capability will enable the development of longer term and more comprehensive capital plans than are possible today. It will also allow for an efficient mobilization of the additional material, equipment, services, labour, and contractor resources that will be required for the successful completion of asset replacements.

The FEU are responsible for managing gas system assets with a book value of approximately $3 billion. Approximately 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40 to 55 years. The FEU anticipate that over the next 40 years approximately two-thirds of current asset will need to be replaced. A significant portion of the O&M funding and FTEs attributable to the LTSP is required to complete a more detailed analysis of all gas system assets. This analysis is needed in order to better understand risks faced by individual assets, to determine optimal maintenance strategies, and to estimate probable end of useful life. As a result of the early stage of this work there are no metrics that can be applied in a meaningful way to compare LTSP work across divisions or utilities.

LTSP O&M

The Asset Management group within the Operations department is responsible for managing all gas delivery assets, including all pipe, stations, and other associated facilities. Included in these responsibilities is the continued evolution and improvement of the Companies' asset management practices. The LTSP is a significant initiative in support of this responsibility. Although the Asset Management group focuses largely on the management of existing gas system assets, in the future it will increasingly need to manage new assets that are required to meet capacity growth and the provision of new services.

Asset Management also relies on other departments in the Companies, who are listed in the table above, to assist in meeting its responsibilities. Resource Development will help in the development of alternatives for large capacity projects and major infrastructure upgrades and to secure the necessary internal and regulatory approvals. Operations Engineering will assist in the development of project cost estimates and in the preparation of feasibility studies that are a precondition for any project approval. Finally, the Procurement group will lead the procurement of the necessary resources needed for the completion of capital projects once they go ahead.

The O&M for the period from 2010 to 2013 represents funding required for two broad purposes and is set out in the table that follows:

Table BCUC IR1.57.1-2 - LTSP Summary

LTSP O&M Resource Use

Amounts in $ Thousands

	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
LTSP Planning & Development	523	822	701	950
Capital Project Support	-	481	2,120	3,557
Total	**523**	**1,303**	**2,821**	**4,507**

The first purpose is to help complete the initial LTSP planning that started in 2010, including the overall asset management framework and planning for process improvements, and to identify areas for new potential technology use. Further effort is required in 2012 and 2013 to continue with the development of this framework. The planning work in 2010 and 2011 also included the completion of an initial asset risk assessment that was used as the basis for identifying projects, primarily in 2012 and 2013, which need incremental capital funding. This incremental capital funding requirement is included in the Application and is discussed in more detail below.

The second purpose of the O&M is to support the development and completion of capital projects. In 2011 this funding was required to help complete initial project cost estimates. These estimates form the basis for the incremental LTSP capital required in 2012 and 2013. It is important to note that the majority of the O&M funding required to support Capital projects was historically treated as part of the Capital cost. Under current accounting guidelines these costs now need to be treated as an O&M expense.

The O&M dedicated to the planning and development of the LTSP and required to support capital projects is funded from two sources, and is set out in the table that follows:

Table BCUC IR1.57.1-3 - LTSP Summary

LTSP O&M Funding Sources

Amounts in $ Thousands

	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Existing Approved O&M	523	1,303	574	671
Incremental O&M per Exhibit B-1	-	-	2,247	3,836
Total	**523**	**1,303**	**2,821**	**4,507**

The first source came from existing approved O&M. The decrease in existing approved O&M after 2011 is attributable to the elimination of the seismic risk and single point of failure analysis that are described in Exhibit B-1 on page 176 and a decrease in funding used to help estimate the cost of capital projects required in 2012 and 2013. The second source is from the incremental O&M requested in the Application and is needed for the further development of the LTSP, for the preparation of project cost estimates, and in the preparation of feasibility studies required for future projects after 2011. The majority of the incremental O&M funding that is requested in the Application, and set out in Table BCUC IR1.57.1-3 above, is required to support of Capital projects. As pointed out earlier, the majority of the O&M funding required to support Capital projects was historically treated as part of the Capital cost. Under current accounting guidelines these costs now need to be treated as an O&M expense.

Incremental O&M funding is required in 2012 and 2013 to enable further development of the Company's asset management practices, including detailed system sustainment assessments, as described above. The full implementation of the required asset management enhancements will take some time given the complexity of the improvements that are foreseen, although a number of important organizational, process and system advancements that form the foundation for technical and process improvements have already been made. Inadequate funding will limit the ability to develop the management systems needed to support a long term asset management view. Current resources are insufficient to complete the considerable reviews and analysis that are required to support future capital expenditure commitments in the amounts anticipated.

LTSP FTEs – O&M

The estimated FTE count required to support the LTSP is used in the same manner as the O&M described earlier. FTEs are needed to complete a range of planning and development work, including the identification of potential projects. A second group is required to help support capital projects once they are approved. These two groups of FTEs are set out in the following table:

Table BCUC IR1.57.1-4 - LTSP Summary

LTSP O&M FTE Use

	2010 Actual	**2011** Projection	**2012** Forecast	**2013** Forecast
LTSP Planning & Development	2.00	2.00	6.88	8.33
Capital Project Support	-	-	2.22	5.20
Total	**2.00**	**2.00**	**9.10**	**13.53**

The estimated FTE count is provided by two sources. First, a number of existing employees have been assigned additional responsibilities related to the planning and development of the LTSP. The second source is from the incremental O&M requested in the Application. These new FTEs are needed for the further development of the LTSP, for the preparation of future project cost estimates, and in the preparation of feasibility studies required for future projects after 2011. A breakout of these two sources for the estimated FTEs required to support the LTSP is provided as follows:

Table BCUC IR1.57.1-5 - LTSP Summary

LTSP O&M FTE Sources

	2010 Actual	**2011** Projection	**2012** Forecast	**2013** Forecast
Existing Approved O&M	2.00	2.00	2.50	3.00
Incremental O&M per Exhibit B-1	-	-	6.60	10.53
Total	**2.00**	**2.00**	**9.10**	**13.53**

All of the O&M FTEs apply to FEI, except for 0.25 in 2012 and 0.33 in 2013 that apply to FEVI.

LTSP Capital

The capital required to complete projects that are notionally related to the LTSP, and set out in Table BCUC IR1.57.1-1 above, is included in FEU's sustainment capital. Sustainment capital requirements are reviewed in detail in section 6.2.2 of Exhibit B-1, with the specific actual and forecast requirements set out in Table 6.2-5 on page 343. Specific projects that are included in sustainment capital are described on pages 346-352 and 356 of Exhibit B-1, with additional capital project information provided in the response to BCUC IR1.91.1.

The estimated LTSP capital requirement in 2012 is $22.6 million and in 2013 is $31.4 million. Of these amounts, $5.5 million in 2012 and $5.2 million in 2013 apply to FEVI.

LTSP FTEs – Capital

The estimated LTSP FTEs required to support the completion of LTSP capital projects forecast for 2012 and 2013, and set out in Table BCUC IR1.57.1-1 above, is estimated to be 5.9 in 2012 and 9.5 in 2013. These additional FTEs are all incremental to those currently with FEU and are required to complete a range of activities related to the completion of LTSP related capital projects discussed in the Application. All of these FTEs apply to FEI, except for 0.50 in 2012 and 0.67 in 2013 that apply to FEVI.

58.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.6, pp. 187-188

Energy Supply & Resource Development – Asset Planning

"The group is responsible for identifying and developing new regional projects as well as system infrastructure projects within the Company's current service areas, including pipeline, compressor, and storage projects. Identifying the need for such major initiatives and projects is important in order to determine and plan infrastructure projects required for system reliability and to meet demand growth. Once these projects have been built and the assets commissioned they become the responsibility of the Asset Management group in Operations for ongoing management." [Ref: p. 187]

"Two new employees were added in 2011 as business development specialists to help the Resource Development group with work identifying and developing new regional projects as well as system infrastructure projects. An additional two employees are expected to be required after 2011 for this group, one in 2012 and the second one in 2013. Both employees will also work as business development specialists that are required to assist the Resource Development group to meet its objectives." [Ref: p. 188]

58.1 Please explain the difference between the work done by this group in identifying required system infrastructure projects and the asset assessments for potential upgrading of infrastructure done/proposed in the Distribution and Transmission groups.

Response:

The two groups work closely together to ensure asset health needs are a key part of the justification and development of large projects.

Resource Development is a small group of specialized resources responsible for identifying and transitioning, from concept to construction, large-scale, multi-year, system infrastructure projects often requiring a high degree of complexity, including pipeline, compressor, and storage. For example, the group would develop a CPCN application requiring the analysis of multiple alternatives, a high degree of stakeholder consultation, and involvement of multiple agencies. There are numerous reasons for these projects, including factors that address capacity, gas supply, system reliability, operational flexibility, aging infrastructure, safety, and environmental stewardship. The group is also currently evaluating projects identified in the Companies' Long-Term Resource Plan, including the Okanagan Reinforcement, Kingsvale-Oliver Reinforcement, and Huntingdon Bypass. In addition to infrastructure projects, other related initiatives are coordinated through this group, such as the extension of the T-South Enhanced Service.

The Asset Management group in Operations (part of Distribution and Transmission) is responsible for the physical distribution and transmission assets of the Companies. They perform asset health reviews and determine all repair or replacement activities, and ensure that all maintenance programs are completed per codes and standards. Once assets have been built and commissioned they become the responsibility of the Asset Management group in Operations for ongoing management.

58.2 Please expand on the specific Resource Development group objectives that are the focus of these four business development specialists. Please identify if any of the work involves Thermal Energy Services, NGV, and/or Biomethane or similar non-traditional utility operations.

Response:

Please refer to the response to BCUC IR 1.58.1 for Resource Development group objectives. The core work completed by this group is not related to Thermal Energy Services, NGV, and/or Biomethane or similar operations. However, if an expansion of the supply infrastructure was required to support these operations, then Resource Development would become involved.

59.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.7.3, p. 193

Customer Service – Bad Debt expense

"Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities." [Ref: p. 64]

"At the time of this Application, no variance to budget for cost items, including bad debt expense, is anticipated for the 2011 projected expenditure. Since bad debt expenditure is driven by a number of factors including economic conditions, it is too early in the year to ascertain the likelihood of a variance to budget for 2011 such as that experienced in 2010." [Ref: p. 193]

59.1 Please explain the apparent contradiction of the two statements on the FEU Company's bad debt experience and expectations.

Response:

The two statements refer to different relative comparisons and thus do not contradict one another.

The first statement refers to lower bad debts experienced in 2010 compared to the budget. Late Payment Charge revenue for this same period was also lower than budget consistent with the bad debt expense.

The second statement refers to the 2011 projected bad debt expense as compared with the 2011 budget. As of the current reporting period, no year-end variance between the 2011 projected bad debt expense and 2011 budget bad debt expense is expected.

60.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.7.3, pp. 201-202

Customer Service – Information Technology

"IT forecasts incremental headcount for the Enterprise, Application and Infrastructure support teams to support the Customer Service department's business processes and supporting technologies. Specifically, the IT department requires additional headcount to bolster the key functions in customer self-serve, billing operations and technical support for IT infrastructure and software applications in production. In order to facilitate these functions, IT forecasts the addition of ten employees for a total of $988 thousand in 2012 with continued support to the Customer Choice program estimated at a combined resource of one employee. It is important to note that labour costs in 2012 represent three quarters of the year (April – December 2012) as the project stabilization period (January – March 2012) remains a charge to the CCE Project. As such, an incremental $310 thousand is required in 2013 to account for the full year."

An important part of the in-sourcing of the customer system was the synergy of existing IT staff and the ability to lever that existing support in a cost effective manner.

60.1 Please confirm these additional eleven FTE are no higher than that as presented in the in-sourcing business case approved as part of the CPCN.

Response:

Confirmed.

61.0 Reference: Energy Solutions and External Relations (ES & ER) Departmental Overview

Exhibit B-1, Application, Part 5.3.8.1, p. 208

TGI 2010-2011 RRA, BCUC 2.1.2 and BCUC 2.13.2; 1992 PNG RRA Decision, p. 19

Community Involvement

In 2008 Terasen Gas spent $448,184 on Community Involvement. The spending by activity for this year was as follows:

Terasen Volunteers & Employee Give Where You Live Program Donations	$151,220
Community Investment projects	$75,574
Local Community Event and Program Sponsorships	$221,390

In 2009, 2010 & 2011 Terasen Gas forecasts to spend $426,000 in each calendar year on Community Involvement. The Budget Forecast for each of these years is as follows:

Terasen Volunteers & Employee Give Where You Live Program Donations-	$200,000
Community Investment Projects	$60,000
Local Community Event and Program Sponsorships	$166,000"

(TGI 2010-2011, BCUC 2.1.2)

61.1 Please provide the actual 2009-2011 Community Involvement expenditures by year and utility (FEI, FEVI, FEW and Fort Nelson).

Response:

This response addresses both BCUC IR 1.61.1 and 1.61.2.

The Table below provides actual community involvement spending for 2009, 2010 and 2011 year to date, as well as the 2011, 2012 and 2013 budgeted amounts for FEI and FEVI. Note that in 2010, the budgets for the FEU's Give Where You Live and Employee Matching Funding programs were transferred from the Energy Solutions & External Relations Department to the Human Resources Department. Spending on community involvement is expected to continue through the revenue requirement period at current levels, with some adjustment for inflation in 2012 and 2013. No other changes have been requested in the Application. FEW and Fort Nelson do not have similar budgets for community investment and program expenditures.

Employee Give Where You Live Program

The FEU *Give Where You Live* program facilitates employee contributions to charitable organizations across the Province. The program offers donations to any non-profit organization for which our employees volunteer. The Companies tops up employee donations by 50 per cent when they give during our annual Giving campaign or through our payroll deduction program. The alignment of our community programs with employee volunteer recognition provides a foundation upon which the FEU can both support and assist their engagement – the result is an positive incremental impact on the communities we serve.

Community Investment Projects

Each year the FEU plan an employee volunteer event in three regions across the Province – the utility contributes $30,000 to each charitable initiative and employees contribute a day of volunteering. These initiatives help to solidify our role as a trusted operator in the community, and communities benefit from the projects as they provide upgrades and improvements to non-profit organizations that serve community interests. Past projects have included a transition home, homes for those living with developmental disabilities, a park for an early childhood development association and sharing farms.

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

Please note that for FEVI, community sponsorship spending is budgeted together with other communications activities. The budgeted amounts for sponsorship on FEVI are therefore approximate; however, actual spending is tracked and has been provided for 2009, 2010 and 2011 (year to date).

61.2 Please provide the proposed 2012-2013 Community Involvement expenditures by year and utility (FEI, FEVI, FEW and Fort Nelson).

<u>Response:</u>

Please refer to the response to BCUC IR 1.61.1.

"The Commission believes that donations are a normal business expense which provides benefits to the customers and the shareholders, and accordingly the cost has been reduced by 50 percent in the Schedules to reflect an equal sharing." (1992 PNG RRA Decision, p. 19)

61.2.1 Are the 2012 and 2013 donation and sponsorship costs shared equally between the ratepayers and the shareholder? If not, why not?

Response:

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.

The 1992 PNG RRA Decision cited in the IR, which was limited to charitable donations only and not sponsorship costs, does not reflect more recent Commission decisions with respect to the FEU and other utilities. In BCTC's F2008 Revenue Requirements Application (Order No. G-64-07, dated June 12, 2007. Appendix A, page 6) and BC Hydro's F2009 and F2010 Revenue Requirements Application (Decision dated March 13, 2009, page 113), the Commission accepted 100 percent cost recovery of donations. The Commission's most recent revenue requirements decision that considered the issue with respect to the FEU was the Commission's Decision dated February 4, 2003 on then BC Gas Utility Ltd.'s 2003 Revenue Requirements Application. That decision also does not apply the 1992 PNG RRA Decision, but permitted recovery of $120,000 in donations.

Encompassing more than just charitable donations, community investment is increasingly a measure of Companies, by municipalities and Indian Bands, whose co-operation and/or approval is required to carry out services to our customers. Councils and officials expect utilities to contribute to health, education, arts, environment and community development initiatives as part of being good citizens of the community. Permissions, approvals, licences, and/or co-operation required to provide prompt and reliable service to customers can be delayed or accelerated as a result of the relationships developed in the community by this kind of participation.

For example, the First Nations Skill Builder program that has been created by FEI, and now partners with all major utility companies in BC, delivers capacity and skills to First Nations allowing them to gain meaningful and sustainable employment that could be achieved through no other additional means. These skills can be utilized to diversify our aging workforce and deliver service to communities not previously accepting of our services. Also, our "Give Where You Live" annual program connects our employees with the communities in which they live - delivering community social service value that has no other means of community support.

Because community investment is required for the successful operation of the utility for the benefit of customers, these costs should also be borne by customers.

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

Exhibit B-1, Application, Part 5.3.8.3, p. 211

New Initiatives

"This increased spending was approved by the Commission and a number of new initiatives were implemented by FEU following the approval. Some of the accomplishments that this increased spending allowed include:

New and expanded energy efficiency programs for 2010 and 2011 that will result in cumulative energy savings of over 700,000 GJs and associated GHG reductions;

- *Bringing carbon neutral biomethane produced using local agricultural waste into the gas distribution system and developing a complete biomethane service offering for customers;*
- *Critical work toward the successful completion of negotiations for service agreements with a number of Vancouver Island municipalities;*
- *The development of new natural gas fueling service for fleet vehicles that will benefit all natural gas customers through increasing year-round loads on the gas distribution system; and"*

62.1 Please provide a breakdown of the increased spending by initiative and year for 2010-2011. Also provide a breakdown of the initiative spending by resource.

Response:

This response also addresses BCUC IR 1.62.2.

The referenced paragraph is intended to be an introduction to initiatives that have been implemented by the ES&ER group since the submission of the 2010-2011 RRA and which are discussed within the 2012-2013 RRA. Details of the forecasted costs for these initiatives and explanations of these initiatives have been provided in the Application (Exhibit B-1) as follows:

New and Expanded Energy Efficiency Programs

A complete explanation of Energy Efficiency and Conservation ("EEC") programming is contained in Appendix K of the Application. Actual expenditures in 2010 on EEC for both FEI and FEVI are provided in Table 2-3, page 8 and Table 2-4, page 10 of the 2010 EEC Annual Report contained in appendix K-4 of the Application. These tables should be read in conjunction with Sections 1 and 2 of that report for a full understanding of the expenditures and resource allocation. Please see Table K-1 in Appendix K-1 for approved 2010 and 2011 funding, and Table K-2 in Appendix K-1 for funding levels applied for in 2012 and 2013. All of Appendix K-1 should be read for a full understanding of EEC funding allocations for those years.

Carbon Neutral Biomethane

A full explanation of this initiative is provided in Appendix J of the Application. Actual, projected and forecast capital costs related to the Biomethane initiative are provided in Table J-1 on page 6 of Appendix J. Actual, projected and forecast O&M costs by resource for the biomethane initiative are provided in Table J-2 on page 8 of Appendix J. The actual amounts in deferral accounts by year are provided in Table J-3 on page 9 in Appendix J. Our biomethane initiative has been the subject of a separate BCUC application and approval process.

Vancouver Island Service Agreements

The negotiating of new operating agreements with Vancouver Island municipalities has been necessary as many of existing agreements on the Island are due for renewal in 2012. These agreements give FEVI the authority to operate within the municipality and help us coordinate construction activities with municipal needs. This initiative is a basic part of ongoing O&M activities required to serve natural gas customers on Vancouver Island and as such has not been tracked separately from other O&M activities to the extent requested in this IR. Once new service agreements are in place the efforts of those staff involved will shift to other important needs in the ongoing management of our important relationships with municipalities, first nations and government at all levels.

Natural Gas Vehicle Fueling Service

The natural gas vehicle fueling service initiative is fully described in Appendix I of the Application. Full development of an NGV fueling service offering occurred during 2010 and 2011, with an application currently before the Commission awaiting final approval. As part of our ongoing commitment to meet the needs of natural gas customers, this O&M activity necessary to develop the initiative has not been tracked separately from other natural gas related O&M, as discussed further in response to BCUC IR 1.162.1. A summary of capital and O&M cost estimates for fuelling stations and natural gas delivery for Rate 16 NGV customers for 2011, 2012 and 2013 are provided in the following table along with the revenues that this initiative is expected to generate. Appendix I fully explains the details behind the revenues and costs for this initiative. Business development activities (O&M) for these services are not budgeted separately from other natural gas business development activity for these years; however, an estimate for these costs is provided and discussed in Section 5 of Appendix I, pages 14 and 15.

Forecast Summary of NGV fueling station costs and revenues.

Forecast Summary	2011	2012	2013
Fueling Stations			
Estimated total number of stations	4	7	11
($ thousands)			
Capital Costs	3,800	4,000	3,800
Annual O&M		358	579
Annual Contract Revenue	341	2,107	3,104
Natural Gas Delivery			
Delivery Margin + Rate 16 Revenue	259	1,636	2,295

62.2 Will the increased spending on the initiatives listed above continue in 2012 and 2013? Please provide and explanation for each initiative.

Response:

Please refer to the response to BCUC IR 1.62.1.

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

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

Communications and Public Affairs Plan

"A communications and public affairs plan was also made a priority for funding reallocation and continues to be implemented."

63.1 Please provide the "communications and public affairs plan" and amount of the reallocation of funds to the "communications and public affairs plan" from other activities by year for 2010-2013.

Response:

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.

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. At this time, there are no substantive funding reallocations currently planned for 2011, 2012 or 2013. Note that the plan provided recommended actions to capture opportunities that existed at the time the plan was prepared and that the FEU's actual expenditures in some cases reflect adjustments to the plan in response to an ever-shifting business environment.

The Communications and Public Affairs Plan is a key, strategic communications-planning document that will deliver important customer benefits. Firstly the plan serves to focus the organization's communications and outreach efforts to address what customer groups and other stakeholders have told the FEU, specifically, to communicate about energy solutions that help them manage energy cost pressures. The plan helped to identify a range of strategies that would effectively speak to these customer expectations and increase customer satisfaction.

Secondly, the document serves to focus the organization's efforts to achieve the following:

- strong employee engagement and goal alignment to ensure effective customer care;
- energy solutions that optimize the use of conventional natural gas.

- communicating the development of a broader range of thermal energy solutions being sought by our customers and ensuring that natural gas remains an important part of B.C.'s energy mix;
- energy efficiency and conservation tools and resources; and
- strong commitments to communities.

In summary, the Communications and Public Affairs Plan represents a key planning document designed to focus the organization on key activities that will deliver better customer service, and help to ensure that natural gas remains an important building block of B.C.'s long term energy solution.

64.0 Reference: Energy Solutions and External Relations

Exhibit B-1, Application, Part 5.3.8.5, p. 213

Codes and Regulations Operating Costs

"…the Mainland natural gas Safety Management Plan to meet the requirement of the CSA Oil and Gas Systems Standard Z662-07. Part 10.2 of the Standard indicates that operating companies must 'develop, implement and maintain a documented safety and loss management system for the pipeline system that provides for the protection of people, the environment, and property'.[86]"

64.1 Does CSA Oil and Gas Systems Standard Z662-07, Part 10.2 specifically require that operating companies develop safety education programming?

<u>Response:</u>

This response addresses both BCUC IRs 1.64.1 and 1.64.2.

The need for operating companies to develop safety education programming as part of their safety and loss management and integrity management systems is defined in a number of areas within the Pipeline Standard Z662-07, including Part 10.2, Annex A, Annex M and Annex N.

In addition to the above noted reference from Standard Z662-07, which clearly sets out the requirement for Operators with respect to the implementation of a safety and loss management system that protects people, the environment and property, Part 10.2.2 on page 177 identifies Annex A of the Standard as the recommended practice for a safety and loss management system. Part A.4.3.2 of Annex A on page 342 of the Standard Z662-07 states that:

> *"Management shall develop and implement procedures for internal and <u>external</u> communications that effectively support the safety and loss management system".* [emphasis added]

While Annex A is identified as a recommended practice, the FEU consider its inclusion in the Standard and reference in the mandatory Part 10.2 to make it an industry standard. In managing risk; therefore, the FEU consider it necessary to meet this standard.

Annex M sets out the distribution system integrity management guidelines. Parts M.10.2 and M.10.5 of Annex M state that improved public awareness and education programs should be implemented to reduce the frequency of failure and damage incidents, as well as to reduce the consequences of such failure or damage incidents. Annex M appears as an informational section of Standard Z662-07 that is optional for distribution system owners and operators;

however, the FEU believes that the inclusion of this Annex establishes its implementation as an industry standard and therefore considers its implementation as necessary.

Annex N sets out guidelines for pipeline integrity management programs and states that improved public awareness of and education about the pipeline should be used to reduce the frequency of failure incidents, the frequency of external interference incidents and the consequences of such incidents (Parts N.12.2 and N.12.5). The formal adoption of Annex N by the BC Oil and Gas Commission as a requirement for owners and operators of pipelines confirms that Annex N is now a mandatory standard. Attachment 64.1 contains Information Letter #OGC 06-12 setting out Annex N as a requirement for pipeline owners and operators.

In summary, the FEU believe the importance of communicating with the public about natural gas safety is an integral part of the Oil and Gas Systems standard. A properly funded public safety education program is good operating practice and will meet the requirements of Section 10.2 of the standard.

"Further, Annexes M and N of Z662-07 guide the development and implementation of integrity management systems for gas distribution and pipeline systems."

64.2 Do CSA Oil Annexes M and N of Z662-07 specifically require that operating companies develop public safety education programs?

Response:

Please refer to the response to BCUC IR 1.64.1.

65.0 Reference: ES & ER 2012 and 2013 Forecast - Mainland

Exhibit B-1, Application, Part 5.3.8.5, pp. 214-15

Public Safety Education

"Approximately two thirds of the incremental funding requested for public safety education is expected to be spent on gas odour and action awareness in 2012 and 2013 in addition to current activities. In the 2010-2011 RRA, FEU requested and received approval for $1.0 million in safety awareness spending, primarily to increase the public's awareness of how to identify and respond to a gas leak.

...Table 5.3-40 shows that the number of third party damage incidents in each the past 5 years decreased from 2007 to 2009 and then seems to have levelled off.

...The additional funding of $750 thousand in 2012 and $850 thousand in 2013 will bring FEU's annual safety education spending during the test period closer to $2 million, or approximately $2 per customer, annually."

65.1 Given that "third party damage incidents in each the past 5 years decreased from 2007 to 2009 and then seems to have levelled off", please quantify the safety improvements that FEI expects to achieve as a result of the additional funding of $750 thousand in 2012 and $850 thousand in 2013 (fewer third party damage incidents, reduced time required for gas odour calls).

Response:

With the required additional funding, FEI will continue to implement awareness initiatives that will target improvements in public safety with regard to gas odour recognition and taking safe action as well as the reduction of the current number of third-party damage incidents. Expected percentage increases in gas odour awareness or reductions in third-party damages for each safety education dollar spent are difficult to predict, due to the large number of factors that could affect such an outcome. FEI is also not aware of any studies that have successfully identified such improvement factors.

Page 214 of the Application (Exhibit B-1) explains that current gas odour and action safety awareness levels are currently low and that awareness levels of at least 50 percent (of people who can recall our safety message without assistance) are targeted. 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.

Marketing experts indicate that message recall and communications' effectiveness are dependent on the clarity, consistency and frequency of the message. The FEU's own primary research has also shown that unless a message becomes internalized as knowledge, recall eventually dissipates once a message is no longer repeated. FEI requires this additional funding to continue to strengthen the public safety education messaging on excavation diligence, to increase the number of times that the messages are delivered and to ensure that the messages reach the entire service area. FEI expects that in addition to other public safety initiatives it is undertaking, an enhanced public safety education program will reduce the number of third-party incidents below current levels. We also expect that a reduction in damage incidents will reduce the operational response requirements for crews, technicians and managers responding to such incidents, although this expectation is also difficult to quantify. It should be noted that the number of third-party damages cannot be directly correlated to the number of gas odour calls, as there are many reasons unrelated to excavation that can cause a member of the public to make such a call.

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. The remaining 10 percent of the total amount will be spent on seasonal gas safety awareness programming. It is FEI's intent to use the required additional funding in a prudent and diligent manner to enhance public safety education in order to reduce risk to people, property and the environment.

66.0 Reference: ES & ER 2012 and 2013 Forecast - Mainland

Exhibit B-1, Application, Part 5.3.8.5, pp. 215-216

Forecasting, Research and Integrated Resource Planning

"ES&ER will require $1.616 million in 2012 and a further $299 thousand in 2013 in support of the forecasting, research and integrated resource planning activities and the Biomethane service offering."

66.1 Please provide a breakdown of the $1.616 million in 2012 and a further $299 thousand in 2013 by the Commission Directive/FEU listed in Table 5.3-41 and the Biomethane service offering. Also provide a breakdown by year and resource.

Response:

The portion of the $1.616 million required to comply with Commission directives and stakeholder expectations listed in Table 5.3-41 is $1.2 million in 2012, of which approximately $555 thousand is labour and $645 thousand is non-labour resources. This spending forecast anticipates that it will take some time in early 2012 to hire the required labour resources. In 2013, the required labour resources will be in place resulting in a further $300 thousand requirement in 2013 reflecting a full year of staffing.

Due to the interrelated nature of the activities needed to meet the Commission directives contained in the Commission's Decision on the Companies' 2010 LTRP[11], the FEU did not approach the problem of funding these activities by individual directive. As a result, the FEU cannot provide the requested breakdown. Please see the response to BCUC IR 1.66.2 for an explanation of the FEU's approach to determining the funding needs for these activities and the response to BCUC IR 1.68.1 for an explanation of how the required activities and funding relate to the Commission directives and stakeholder expectations.

The biomethane portion of these costs is summarized on Page 217 of the Application (Exhibit B-1) and further detailed in Appendix J, Table J-2. In 2012 this amount totals $416,384 which is comprised of $100 thousand in labour costs, $10 thousand in computer costs, $300 thousand in customer education costs and $6,384 in inbound calls. In 2013 there is an incremental $2 thousand in labour costs, -$10,000 in computer costs, $6,000 in customer education costs and $128 in inbound calls, resulting in a net incremental cost in 2013 of -$1,872.

[11] Decision dated February 1, 2011 and Order G-14-11

66.2 Please identify which Incremental Budget Items in Table 5.3-41 are due to Commission Directives or Stakeholder Expectations and the incremental 2012 and 2013 spending related to each item. Also provide a breakdown of each incremental item by year and resource.

Response:

The FEU acknowledge that a better title for the right hand column of Table 5.3-41 on page 216 in the Application (Exhibit B-1) would be "Funding Requirement and Description", as the table does not truly identify individual budget items, but rather provides a list of interrelated activities that require additional funding. The FEU believe that all of the incremental activities and funding requirements identified in Table 5.3-41 are due to both Commission directives and stakeholder expectations. The response to BCUC IR 1.68.1 explains how all of the activities and funding in that table are related to the Commission directives and how the stakeholder expectations are entwined with the Commission directives.

A direct assignment of each individual item on the left hand side of the table to an individual FTE is not reasonable. Many of the activities needed to address Commission directives will take the time of more than one new staff member, and these activities cannot be assigned before staffing resources have been acquired. 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. Please see the response to BCUC IR 1.66.1 for a description of the required incremental funding by year and resource.

67.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.8.2, pp. 210-211

Energy Solutions and External Relations – Additional FTE in 2011

"Three of the fifteen are included in the Customer Service Department in '2011 approved', but are moved into the ES&ER department in '2011 projection', therefore representing a transfer and not an actual increase in headcount within the company. Four new positions in the Energy Solutions group were created through a reallocation of approved budget spending to ensure the group continued to meet its commitments to customers. Finally, one position was created to manage the new biomethane service offering and was approved by Commission Order G-194-10 as part of a separate biomethane application."

67.1 What function was transferred from Customer Services to move the three employees to ES&ER?

<u>Response:</u>

These three positions, providing assistance in managing customer relations and key customer accounts, joined the newly created ES&ER department from Customer Service. When these two departments were formed from the previous Marketing and Business Development ("M&BD") department, these three positions originally had a reporting relationship to one of the Customer Service Managers within Customer Service. It was later identified that these roles were more suited to reside within the Energy Solutions group. With this transfer, the two new ES&ER and Customer Service departmental budgets created from the former M&BD budget remained equal to the original approved 2011 M&BD budget.

67.2 Where was the approved budget that was transferred to ES&ER to fund the four new employees in 2011?

<u>Response:</u>

The transfer involved a reallocation of labour and non-labour budgets from within the newly created ES&ER department budget. Consulting budget dollars and savings from the existing labour budget were sufficient to fund these four positions. In this transfer of budget dollars, the combined ES&ER and Customer Service budgets remained equal to the original 2011 approved Marketing and Business Development budget from which they had evolved.

68.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.8.5, pp. 215-216

Energy Solutions and External Relations – Long Term Resource Plan

"In consideration of these needs, the Commission's decision on the 2010 LTRP together with Commission Order G-14-11 requires FEU to comply with a number of related directives. Currently, our integrated resource planning function has very few resources that can be dedicated to these activities. Therefore, In order to comply with these directives and to implement additional initiatives that will improve FEU's integrated resource planning, we are requesting an annual budget increase of $1.5 million, including an additional 7 employees."

"Table 5.3-41 provides an explanation of the requested incremental funding in relation to the Commission's directives and new FEU initiatives related to our long range planning activities."

"Currently, 1 full time employee and one shared analyst position are dedicated to the preparation of the Long Term Resource Plan."

68.1 Please provide a extract from Table 5.3-41 of just the items required by Commission Order G-14-11, and provide the specific reference from the Order for each item.

Response:

The Commission directives, stakeholder expectations and FEU initiatives that FEU is addressing with the incremental funding are interrelated (see also FEUs responses to BCUC IRs 1.66.2 and 1.66.1). Table 68.1 below is a reproduction of Table 5.3-41 with the addition of an explanation column that describes how all of the activities and funding listed in the table relate to the Commission directives set out in the decision on the 2010 LTRP.

The Commission's preamble to the listed directives in their decision on the 2010 LTRP make it clear that all of these issues are interrelated and significant additional work is required in the preparation of FEU's future Long Term Resource Plans. The preamble, together with the listed directives, is also copied below for convenience. Table 5.3-41 of Exhibit B-1 in fact does represent FEUs understanding of the activities that are required to comply with the specific Commission orders.

Table 5.3-41: Additional Resources are Required to Comply with Stakeholder Expectations and Commission Directives Related to Long Range Planning

Commission Directive / FEU Initiative	Explanation	Incremental Budget Item and Description
20 year vision - Macro-economic analysis and scenario development / review - Market transformation scenarios - Contribution to GHG reductions - New technology forecasting - Impact on BC Energy Objectives - Drivers for non-EEC/infrastructure resource requirements	*These activities are required by Commission directive no. 1. Sub-bullets in left hand column describe FEU's understanding of scope of this directive. All activities and funding in right hand column and some from other rows are required to meet this directive.*	- Staffing for increased economic research, analysis and reporting - Staffing for increased technology research, analysis and reporting - Staffing for increased energy use and GHG modelling, analysis and reporting - Funding for economic studies and reports, access to economic forums - Funding to support market access and transformation studies, reports and analysis - Staffing and activities associated with investigating non-EEC/infrastructure resource requirements

Commission Directive / FEU Initiative	Explanation	Incremental Budget Item and Description
New Stakeholder Consultation Initiatives - Resource Planning Advisory Group, Community Consultation Activities and other new consultation activities	*This item is not specifically listed in the Commission directives; however, FEU committed to setup a Resource Plan Advisory Group during the proceeding. The Commission Panel commented as follows:* *"With respect to stakeholder input, the Panel is most encouraged by Terasen's intention to establish a Resource Plan Advisory Group as it may provide a sounding board and assist in the preparation of future plans." (p. 13)* *"The Panel believes that these recommendations along with the stated intention of Terasen Utilities to setup a Resource Plan* *Advisory Group will be helpful in promoting further development of the long term planning process." (p. 19)* *Increased consultation activities are a necessary part of the additional scenario setting, analyses and review of outcomes needed to improve the LTRP. The need to consult with stakeholders is apparent throughout the Commission decision report and is highlighted by the discussion of intervener submissions in the preamble to the directive. All activities and funding in the right hand column of this row are required for successful stakeholder consultation.*	- 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

Commission Directive / FEU Initiative	Explanation	Incremental Budget Item and Description
EEC Planning and Impacts of New Initiatives - GHG impact modelling and analysis - Improved analysis of long term EEC planning and scenarios - Impact of new service initiatives on EEC scenarios, resource requirements, demand and emissions	*These activities are required by Commission directive no. 2. Sub-bullets in left hand column describe FEU's understanding of scope of this directive. All activities and funding in right hand column of this row and some from other rows are required to meet this directive.*	- Staffing for increased 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 - Funding for increased research into and review of technology advancements affecting energy use

Commission Directive / FEU Initiative	Explanation	Incremental Budget Item and Description
Planning Environment and Demand Forecasting - Develop end-use forecasting methodology - Compare with traditional methodology and prove out new methodology pros and cons - Broader consideration of economic inputs to and impacts of planning scenarios - Incorporate potential legislative, regulatory or market transformational changes into forecast and resource assessment - Rigorous analysis of scenarios that consider the impact of new service initiatives on resource needs, energy demand and GHG emissions - Consideration of other variables that could impact scenarios and results - Regional / provincial thermal energy demand investigations - Regional / provincial transportation energy demand investigations	*These activities are required by Commission directive no. 3. Sub-bullets in left hand column describe FEU's understanding of scope of this directive. All activities and funding in right hand column of this row and some from other rows are required to meet this directive.*	- 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 for increased consideration of economic variables in developing future scenarios and considering impacts on energy use and resource needs - 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 - Funding to support additional staffing and forecasting initiatives

Commission Directive / FEU Initiative	Explanation	Incremental Budget Item and Description
New report and document preparation requirements	*This item is not specifically listed in the Commission directives; however, improved reporting and documentation throughout the integrated resource planning process is necessary to develop, present and gather feedback on the new activities required by the Commission directives. The amount of reporting and documentation will increase in order to meet this requirement.*	- Staffing and funding support for communicating issues and analysis results and for including the increased long-range analysis and scenario considerations within the LTRP

The following is an excerpt from pages 21 to 25 of the Commission's Decision, dated February 1, 2011 on the FEU's 2010 Long Term Resource Plan:

3.0 DISCUSSION OF ISSUES ARISING

3.1 Quality of the 2010 LTRP

In Section 2.0 the Commission Panel determined that acceptance of the Terasen Utilities 2010 LTRP is in the public interest. In making this determination, the Panel noted that the 2010 LTRP was in its view adequate only and there were a number of areas which could be improved upon in future resource plan submissions.

Among the Interveners, both the CEC and BCOAPO have expressed concerns with respect to the 2010 LTRP.

The CEC submits that there are numerous items which have not been factored into Terasen's capital and supply plans over the 20 year planning time frame. These result in the Company failing to undertake a broader integrated and consolidated view of the issues facing it and the initiatives it may be considering. In addition, the CEC notes that Terasen's resource plan fails to "lay sufficient ground work for the nature and scale of the activities which would be required to contribute significantly to the BC Energy Objectives." (CEC Final Submission, pp. 2-4) The CEC makes the following recommendations with respect to inclusions in future plans:

- Scenarios which include a full 20 year response to the British Columbia's energy objectives with particular regard to GHG emission reduction planning.
- Development of a practical number of scenarios related to GHG reduction, electricity and fuel pricing, fuel switching and technology development to allow Terasen to demonstrate its response to varying circumstances.
- Scenarios covering the transformation of trucking markets in BC to natural gas which would include analysis of and impact on the government's objectives for GHG reduction.
- With respect to EEC funding to address key market transformations to be considered for long term funding based on the requirements necessary to achieve the desired result.

- To broaden its resource planning to cover the full 20 year time-frame and examine alternatives to defray system upgrade costs. Referring to this the CEC submits that among the alternatives consideration should be given to targeted EEC programs where the result might be the deferral of capital expenditures due to conservation and efficiency improvements.

(CEC Final Submission, pp. 6, 8, 11, 13 and 14)

BCOAPO, in addition to raising concerns as to the need to address what it terms to be the "big question," makes the observation that given the sector is facing dramatic transformation, the 2010 LTRP projects minimal consideration of the changes which might be expected over the 20 year period covered by the plan. It is BCOAPO's position that an aim of the plan is to provide a roadmap for the evolution and direction of Terasen in future years. Aside from suggesting that Terasen Utilities may wish to consider a more robust econometric forecasting approach, BCOAPO provides little specific comment on how the plan can be improved. (BCOAPO Final Submission, pp. 1-3)

Terasen in Reply notes that the purpose and scope of the resource planning process is found in section 44.1 of the *UCA* and the Commission's Resource Planning Guidelines. Additionally, the Company submits that the focus for the 2010 LTRP is on forecasted demand and its plans to meet that demand through resource acquisition and demand-side measures. Terasen's position is that while long-term resource planning may support or provide context for planned initiatives, it does not replace the need for individual *UCA* approvals allowing them to move forward. With respect to the CEC's specific recommendations, Terasen notes that many of the requests for further analysis are in process and points to its answer to the CEC 2.1.1 as supporting this. Further, it sees no need for the econometric forecasting approach suggested by BCOAPO. On a final note Terasen Utilities support the value of scenario analysis but express the need to limit the types of analysis as a practical matter. (Terasen Reply, pp. 1-6)

Commission Panel Directives

As stated previously by the Panel, the 2010 LTRP, while accepted, is viewed as being just adequate. It falls short of our expectation that resource plans should provide a comprehensive 20 year view of a utilities trajectory and provide a strong support for programs and initiatives which will be filed with the Commission. The Panel is also disappointed that there was no attempt to describe a vision of Terasen Utilities 15-20 years from now. Adding this sense of vision completes the picture of how the actions being undertaken in the near future in combination with plans in an early stage of development will create the Terasen of tomorrow. In this way Terasen can demonstrate it is capable of meeting the challenges presented by British Columbia's energy objectives and evolving government policy.

The foundation of any planning exercise is the analysis which is conducted to better understand the issues and challenges arising or anticipated to arise in the coming years. This is often supported by the development of well crafted scenarios outlining in detail a potential outcome or series of outcomes. The CEC has pointed out in its recommendations that Terasen would benefit from additional work in this area. Its concern is the limited number of scenarios and lack of detail for each falls short of providing a clear picture of the impact of the challenges faced by the Company and how its plans will assist in meeting these challenges. The Panel agrees with the CEC on this matter.

The Commission Panel has considered this and the balance of evidence in developing a series of directives for the next resource planning exercise. We believe these will provide some guidance in moving this process forward. Accordingly, pursuant to section 44.1(2) (g) of the *UCA*, the Panel directs the following be included in the next LTRP:

1. Terasen Utilities – A 20 Year Vision

This vision could describe what Terasen may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe.

Areas which are appropriate to be covered in preparing this Vision include but are not limited to the following:

- The extent to which markets will be transformed.
- The extent to which Terasen can contribute to overall British Columbia GHG reduction objectives.
- The impact the Company's contributions to GHG reduction will have on demand.
- The importance new technology and new initiatives will have on the overall business, and their significance in terms of percentage share of its traditional business.
- An outline of what initiatives are currently planned or being considered and the status.
- The impact Terasen's efforts have, and expect to have, on meeting British Columbia's energy objectives.
- The key drivers impacting the need and timing for human, physical and other (information technology, capital etc.) resource requirements.

2. GHG Reduction Targets – EEC Planning and Impacts of New Initiatives

In respect of GHG reduction targets as impacted by EEC Planning and New Initiatives the Commission Panel directs future LTRPs to include the following:

- An analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time.
- Greater coordination between EEC planning and the development of future resource plans. This will allow for a more detailed presentation of future EEC programs over a longer time period with expected impacts to be included as part of the LTRP process.
- Development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast and GHG emission reductions.
- An outline of the impact of the implementation of New Initiatives on the demand forecast and GHG emission reductions.

3. New Business Environment and Approach to Demand Forecasting

Future LTRPs need to more adequately convey Terasen Utilities' understanding of the new energy and business environment, its impact on gross demand and how resource plans will be reflective of future demand growth. Accordingly, Terasen is directed to include the following in future resource plans.

- A description of the new end-use forecasting methodology, how it compares with Terasen's traditional demand forecasting approach, and reconciliation of the results of the two different approaches.
- The development of a most likely or reference case demand forecast and outline of the underlying assumptions taking into account potential legislative, regulatory or market transformation changes.
- An integration of the reference case demand forecast with the EEC scenarios and a description of the impacts.
- A detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios.
- A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.

Finally, Terasen is directed to provide an estimate of the extent to which its proposed programs and initiatives will contribute to the achievement of British Columbia's energy objectives.

68.2 Please explain how many other resources from across the FEU companies are involved in the LTRP. Please comment on whether the addition of another 1.5 FTEs would result in twice the quality of LTRP than as previously filed.

Response:

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. For example, the number of engineers and analysts required to fully investigate all the options to increase capacity on the Vancouver Island transmission system in the 2006

Resource Plans was greater than that employed for the 2008 Resource Plans for that activity once a final decision on the Vancouver Island system constraints was made. 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. An additional 1.5 FTEs would allow the FEU to conduct some of the additional analyses and activities required by the Commission directives in the 2010 LTRP Decision, but would fall well short of the desired outcomes.

The 2010 LTRP was completed in a similar manner and standard to that of previous Resource Plans, all of which were accepted by the Commission. This new step change increase in the need for resources, analysis, consultation and reporting is the result of the changing energy planning environment that the FEU are operating within, the associated shifting in customer needs and the increased uncertainty about how future energy needs will be met. As a result, the Commission has directed the FEU to significantly increase the level of activity and effort the FEU undertake with regard to long range planning, and the FEU agree with this need. The FEU have examined the resources and funding that it will take to meet the 2010 LTRP Decision directives and have included those required resources in the 2012-2013 RRA.

69.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.9.3, p. 223

Information Technology – Savings on US dollar exchange rate

"There were some very specific one-time opportunities related to software in 2010 that drove lower O&M of approximately $360 thousand. These included the elimination of PST mid-year (returned to customers through the Income Tax Variance deferral account), savings related to the US dollar conversion and inflationary savings on several contracts with software companies, and finally the pre-buying of software licenses and maintenance plans for infrastructure administration and security software. The IT department anticipates that its 2011 spending will be in line with approved."

69.1 Please provide the US dollar exchange rates used in the IT O&M budgets for 2010 and 2011, and compare these to the actual and currently projected exchange rates for 2010 and 2011. Please provide the savings in 2010. Based on the current and projected exchange rates, what is the expected total savings, on IT O&M spending for 2011?

Response:

The US Dollar (USD) exchange rates used in the IT O&M Budgets for 2010 and 2011 are $1.1615 and $1.1273 respectively. The actual 2010 USD exchange rate over the year related specifically to IT transactions was $1.0351. The forecasted USD exchange rate in 2011 is $0.9737. Based on the difference in budgeted exchange rates to actual in 2010 on a total USD amount of $493,406.68, the savings amounted to $62,366.60 CAD. For 2011, savings are expected to amount to $75,787.27 CAD.

69.2 Please provide the total US dollar denominated costs for Information Technology O&M embedded in the FEU O&M expenses for 2012 and 2013. Based on the current and forecast exchange rates, what is the expected total savings, on IT O&M spending for 2012 and 2013? Please identify where this reduction can be seen in the Application.

Response:

The total USD denominated costs for IT O&M embedded in the FEU's 2012 and 2013 O&M expenses are $746,065.75 and $768,945.75. Based on the exchange rates forecast in the

Application of $1.0125 for 2012 and $1.0284 for 2013 and comparing to the CAD amounts at the current 2011 USD exchange rate of $1.0141, there will be a loss of approximately $1,100 CAD in 2012 and a savings of approximately $12,000 CAD in 2013, which form part of the contract inflationary costs included in the Service Standards and Reliability cost driver.

69.3 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 Parts 2.6 and 3.3 of Appendix G.

Response:

Please refer to the responses to BCUC IRs 1.69.1 and 1.69.2.

70.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.10.4, p. 231-232

Operations Engineering – CSA S250 Mapping Standard for Underground Utilities

"The soon to be published CSA S250 Mapping Standard for Underground Utilities is the first new driver of funding requirements. This new standard "will specify the mapping requirements for the recording and depiction of underground utility infrastructure, and related appurtenances at or near grade and will apply to proposed existing, abandoned in-place, retired, or reserved for future use, underground utility infrastructure."

70.1 Please provide a description of the existing mapping process at the FEU, including how the FEU currently map the existing, abandoned in-place and reserved for future use underground utility infrastructure. Please explain how the FEU existing process differs from the new CSA S250 Mapping Standard.

Response:

The FEU currently map changes to the existing, abandoned in-place and reserved for future use underground utility infrastructure when construction drawings for specific jobs are required. Our planners and engineers provide information and instruction on the required changes to the plant. Our landbase is updated in the immediate area where the change to the plant is to be made and then the plant change is mapped in the GIS system. In conjunction with the mapping activities, construction drawings are prepared showing the size of main, material, offset, and third-party underground utilities. The construction drawings are circulated for approval and any required changes incorporated into the maps and drawings. Once the specific job is complete, changes resulting from construction are mapped in the GIS system.

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.).

70.2 Please provide a schedule showing the existing and proposed mapping staff at the FEU, including the GIS staff, their position titles, numbers of FTE, and total costs separated by at least the categories of labour, consultants, equipment, and other.

Response:

The following schedule shows the existing (2011) and proposed (2012 and 2013) mapping staff and associated costs.

Positions	2011	2012	2013
GIS Drafting Leader	1	2	2
Tech 3 - GIS	3	3	3
QA/QC Tech	2	2	2
GIS Drafter 3	3	3	3
GIS Drafter 2	3	3	3
GIS Drafter 1	10	10	10
OSR 2	2	2	2
Total FTE	**24**	**25**	**25**
O&M Costs			
Labour	$ 777,000	$ 877,000	$ 877,000
Employee Expenses	$ 8,000	$ 8,000	$ 8,000
Materials and Equipment	$ 31,000	$ 31,000	$ 31,000
Computer Costs	$ 10,000	$ 82,000	$ 82,000
Fees and Administration	$ 172,000	$ 172,000	$ 172,000
Contractor and Consultant	$ 25,000	$ 75,000	$ 25,000
Total Costs	**$ 1,023,000**	**$1,245,000**	**$1,195,000**
Inflation not included			

71.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.10.4, p. 232

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

"New regulations made under OGAA require pipeline companies to perform extensive consultations with communities, landowners, First Nations, environmental groups and industry, reflecting the needs of the people, environment, industry and government. In response to the new and expanded requirements of the OGAA, we need an additional $103 thousand in 2012 to be maintained in 2013 to fully fund an employee for the OGAA Project Coordinator position."

71.1 Please provide a schedule for 2009 through 2013 showing the existing and proposed staff across the entire FEU that consult with communities, landowners, First Nations, environmental groups and industry. Please provide the data by department within the FEU and separated by type of stakeholder, type of consultation, department FTE for this function and total costs by department.

<u>Response:</u>

The new Consultation and Notification Regulation[12] ("CNR") created pursuant to the Oil and Gas Activities Act ("OGAA") prescribes a formal process for pipeline companies who are seeking OGC permits to formally notify and/or consult with individuals or organizations that may be affected by OGC permits. This is a new regulation that did not have a predecessor/counterpart under the former BC Pipeline Act. The Oil and Gas Commission has also created an extensive and step-by-step Consultation and Notification Manual[13] to ensure that the requirements are clearly understood and followed by industry.

The table below shows the FEU staff and O&M costs by department involved in consultation and notification activities with First Nations, local government, organizations or land owners, for the 2009 -2013 period in relation 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.

[12] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/1976694347#section4

[13] http://bcogc.ca/document.aspx?documentID=909&type=.pdf

Activity	FTE 2009	O&M 2009 ($000)	FTE 2010	O&M 2010 ($000)	FTE 2011	O&M 2011 ($000)	FTE 2012	O&M 2012 ($000)	FTE 2013	O&M 2013 ($000)
Community Relations Capital project support *	3	356	3	357	3	384	3	407	3	421
Property Services Capital project support **	2	203	2	203	2	208	2	208	2	211
OGAA Consultation and Notification compliance	0		0		0		1	103	1	106
Total	**5**	**559**	**5**	**560**	**5**	**592**	**6**	**718**	**6**	**738**

* Community Relations activities include a broad range of communications and interactions with First Nations, local government, organizations or land owners outside the scope of compliance requirements of the Consultation and Notification Regulation of the Oil and Gas Activities Act. The amounts in the table are pro-rated estimates of the time and resources spent in support of OGC permitted capital projects.

** Property services activities include communication with landowners directly affected by capital projects to negotiate working space, right-of-way and related agreements. These types of agreements are viewed as separate and distinct from the formal Consultation and Notification Regulation process by the OGC. The amounts in the table are pro-rated estimates of the time and resources spent in support of OGC permitted capital projects.

72.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.10.4, p. 232

Operations Engineering – Long Term Sustainment Plan (LTSP)

"For future years, Operations Engineering is forecasting a necessary increase in employees to address new and existing compliance requirements as detailed in Part 5.3.10.4 and to respond to anticipated capital program increases related to the LTSP. The employee increases related to proposed increases in capital spending will predominantly occur within the Project Management Office and will be managed to ensure appropriate resource response to capital project levels and timelines. [Ref: pp. 229-230]

"Operations Engineering needs to increase its resource capacity in order to deliver on the sustainment plan described in Part 6.2. We need an additional $242 thousand in 2012 and $135 thousand in 2013 to provide the required administrative and support resources for the LTSP and programs identified in the plan."

72.1 Please provide a schedule for the total costs of the LTSP, from 2010 through 2013, by department across the FEU, with detail by capital and O&M for the FTE involved.

Response:

Please refer to the response to BCUC IR 1.57.1.

72.2 Please explain if this type of support for capital projects would normally be included in the capital overhead loading.

Response:

Yes it would be. 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 support 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, along with other incremental O&M requested in this Application not classified as direct capital support costs, are subject to the approved overhead capitalization rate of 14 percent.

73.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.11.4, pp. 238-239

Operations Support – Codes and Regulations

"Operations Support requires an additional $105 thousand in O&M funds in 2012 to maintain our fleet of gas detectors due to the introduction of new units that are capable of monitoring methane and other dangerous gases. This funding requirement is critical to the ongoing maintenance of these units as they are the first line of defense for our customers and employees working in an environment where dangerous gases can be present."

73.1 Please explain if this requirement for new gas detectors capable of monitoring methane is in any way connected to the introduction of Biomethane into the FEU system.

Response:

This request is not connected to the FEU's recent expansion into Biomethane. The FEU have deployed these advanced portable gas detector units to all field employees within the Companies to ensure they can quickly and accurately confirm the existence of potentially dangerous levels of product gases within the ambient air during any customer visit or at any other work site. As such, the FEU require additional funds to maintain these portable gas detectors for the safety of both customers and employees.

"In 2014, Measurement Canada, the federal agency that regulates FEU's meter fleet, is legislating sampling plan SS06 which is a more rigorous standard on meter sampling, testing and accuracy tolerances than the existing standard. In particular, SS06 will result in a 50 percent increase in the number of meter samples. As such, in 2013 Operations Support requires $65 thousand to meet Measurement Canada's requirements for testing and reporting of meters in order to avoid potentially costly fines. To ensure FEU's meter fleet meets these requirements and avoids costly fines two additional labour resources will be required in the second half of 2013. These resources will be trained on measurement operations and be involved with additional meter handling and testing so our meter fleet will be in compliance with Measurement Canada's regulations by January 1, 2014."

73.2 Please provide details, for each year of 2009 through 2014, of the number of existing and proposed meter related staff and the number of meter samples.

Response:

The requested breakdown of residential meter sample related staff to ensure compliance with Measurement Canada requirements is provided below.

	2009	2010	2011	2012P	2013F*	2014F
Number of Meter Samples	8116	8248	7937	9000	9000	14000
Equivalent Employee-Years Supporting Meter Samples	4	4	4	4	5	6
Samples/Equivalent Employee	2029	2062	1984	2250	1800	2333

* As referenced above, the incremental employees will be hired and trained in the second half of 2013 in preparation for the increase in residential meter samples beginning in 2014.

74.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.11.4, pp. 239

Operations Support – Service Standards and Reliability – Extension of Asset Life

"Beginning in 2011, FEU began recalling electronic meters installed in vertical subdivisions to be tested for accuracy in accordance with Measurement Canada regulations. At the same time, these meters are scheduled to have their batteries replaced to ensure reliable operation after redeployment to the field. This level of maintenance will continue through 2012 and 2013 and beyond as the next group of installed electronic meters become due for recall. Also in 2010 one of the vendors supplying rotary meters currently deployed in FEU's fleet began offering lithium battery packs to energize the associated micro-correctors in place of the alkaline batteries previously used. This change has resulted in an incremental cost for each meter maintained in the meter shop. The total increase in O&M funding to support the battery replacements in 2012 is $181 thousand and in 2013 an additional $71 thousand. Secondly, FEI will be purchasing additional parts for meter sets to continue delivering gas safely to customers at an additional cost of $149 thousand in 2012. Funding for these materials will allow the Company to extend the life of these assets deferring the cost of replacement."

74.1 Please provide the estimated value of the extension of the service life compared to the additional cost of the lithium battery packs separated from the extension of the service life due to the additional parts for meter sets.

<u>Response:</u>

For clarification, the funding request for lithium battery pack replacement within residential electronic meters and rotary meter micro-correctors is entirely independent of the funding request for additional parts for meter sets. Within the gas distribution industry, a meter set refers to the prefabricated mechanical assembly to which all gas meters are attached. The components for a typical meter set include a single gas meter, a single or multiple pressure regulator, by-pass and shutoff valves and piping with the associated fittings. The meter set is attached to the end of the service at each customer's premise and the design will differ based on the size of the load. As such, the funding request for additional parts for meter sets relates specifically to maintenance activities that are completed upon commercial and industrial pressure regulators to ensure their safe and reliable operation.

The Companies' program to replace battery packs for electronic components involved in metering is important to ensure these assets operate in a cost-effective and reliable manner. A key fact which influences the timing of battery replacement for these devices is the Measurement Canada requirement that all electronic metering devices within the FEU's fleet be recalled to an accredited meter shop for accuracy testing and recalibration. The current mandated time interval between scheduled recalls for these devices is 6 years after the initial deployment and every 5 years for the remaining service life. As such, the most cost-effective time to execute a battery replacement on these devices is when they are in the meter shop for testing and recalibration. With respect to residential electronic meters, the current battery packs are not expected to supply enough energy to allow the meters to operate through two consecutive recall cycles. As the unit cost of a replacement battery pack is estimated to be 66 percent of the cost of an unscheduled field visit, it is prudent to replace the battery packs during the first scheduled recall. Similarly, for rotary meter micro-correctors the existing alkaline batteries frequently do not have the capacity to energize the device between scheduled field visits. As the unit cost of a lithium battery pack is estimated to be 90 percent of a single unscheduled field visit, it is prudent to replace the alkaline batteries with a lithium battery pack at the time of a scheduled recall.

75.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.14.4, pp. 255-256

Environmental Health & Safety – Disaster Recovery Planning

"FEI will attain an expanded DR capacity as well as an alternate location (to Surrey) for first response employees to work from in the event of an impacting event. In 2012 and 2013, $36 thousand is required, in order to purchase licenses, wiring, and other equipment related to telephony; in 2013, a further $50 thousand is required for similar materials that will enable the data access expansion to the DR site. Alternate physical work locations in existing FEI offices in the Lower Mainland will be equipped to manage daily operational requirements outside of the Surrey Operations site. Phone applications will also be expanded to alternate locations, such that post incident system restoration efforts can proceed without significant delay."

75.1 Please explain how these proposed changes fit with the extensive Disaster Recovery systems that were installed in the new Customer Service centre as part of the in-sourcing CPCN.

Response:

The Disaster Recovery systems housed in Prince George contain business critical applications and associated hardware that will only be accessible through the internet or the corporate Wide Area Network if the primary Surrey data center becomes inoperable, but does not provide an alternate workspace for Surrey Operations Centre employees in the event of a disaster.

The proposed changes outlined in the Application (Exhibit B-1), Section 5.3.14.4, pages 255-256 and identified below are to facilitate users' workspace needs in the event of a displacement from the Surrey Operations Centre:

- To equip alternate physical work locations in existing FEI offices in the Lower Mainland, but outside of the Surrey Operations Centre; and
- To expand the phone applications and telephony used in the Surrey Operations Centre to alternate locations.

Telephony encompasses telephones, fax machines and other applications or systems that need phone lines. Currently, the telephone system is non-transferable if the Surrey Operations Centre is inaccessible and/or if the Surrey Operations Centre data centre is severely impacted.

76.0 Reference: Revenue Requirement and Rates

Exhibit B-1, Application, Part 5.3.16.4, p. 265

Vancouver Island O&M Increase

Looking at Table 5.1-1 on page 145, the increase in O&M for Vancouver Island from 2011 to 2012 is about 7.75 percent, much higher than the 4.8 percent average.

Looking at the O&M costs by resource on Schedule 21 of Part 7.1, the combined Fees & Administration Costs and Contractor Costs are up about 12.6% from 2011 to 2012; the footnote references 2012 reflects customer service costs previously contracted.

"In 2012, the $2.25 million increase in this category is primarily due to a $1.5 million increase in the shared service fee from the Mainland … The increase in the shared service fee is reflective of the increase in O&M for the Mainland business areas which provide operational support but do not charge their cost directly to Vancouver Island." [Ref: p. 265]

76.1 Please provide additional detail on the $1.5 million increase in the shared service fee from the Mainland, including amounts included for individual groups and the comparisons for 2010 and 2011. Please provide the comparable detail for Whistler and Fort Nelson.

Response:

Please refer to Table 1 below for the requested data for FEVI and FEW. Fort Nelson is not a separate legal entity from FEI, and as a result no formal shared service agreement between the two regulatory entities exists. For regulatory reporting purposes, an allocation from Mainland Corporate O&M is made, recognizing the functional support provided to Fort Nelson. This allocation is not done at the individual department level; instead the overall O&M for the Mainland, reduced by the total departmental O&M in those departments where Fort Nelson is able to calculate its directly related costs (i.e. Distribution), is used as an allocation base. This approach is consistent with the past practice and was approved by Commission Order No. G-27-08.

Table 1: Shared Services Fee Breakdown by Department

	TOTAL SHARED SERVICES FEE				INCREMENTAL		TOTAL	
	2010		2011		2012		2012	
(in $'000's)	FEVI	FEW	FEVI	FEW	FEVI	FEW	FEVI	FEW
Distribution	$ 1,573	$ 41	$ 1,659	$ 43	$ 269	$ 7	$ 1,927	$ 50
Transmission	109	3	115	4	122	3	237	7
Energy Supply & Resource Development	106	3	108	3	15	0	122	3
Customer Service	285	7	292	8	515	13	808	21
Energy Solutions & External Relations	872	36	886	38	207	5	1,093	43
Information Technology	1,042	27	1,136	28	186	5	1,322	33
Operations Engineering	703	19	746	20	19	0	765	20
Operations Support	466	12	475	13	6	0	482	13
Facilities	164	4	168	4	13	0	181	5
Human Resources	666	16	691	17	83	2	774	19
Environmental & Safety	245	7	251	7	33	1	284	8
Finance & Regulatory	852	22	880	23	49	1	929	24
Corporate	157	5	132	6	(18)	(0)	114	6
Total Incremental Shared Services	**$ 7,239**	**$ 202**	**$ 7,541**	**$ 212**	**$ 1,499**	**$ 39**	**$ 9,040**	**$ 251**

As part of the 2010-2011 RRA process, the FEU had completed a review of their Shared Services agreements followed by KPMG independently reviewing and validating the reasonability of the approach and suitability of the proposed agreements. The incremental shared services amounts proposed in the current Application were calculated in the manner consistent with the shared service allocations included in the 2010-2011 RRA.

The increases in 2012 are primarily driven by the in-sourcing of the Customer Service function and incremental Long Term Sustainment Plan initiatives.

77.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.18.1, p. 272

Corporate Services – Internal Audit

"The overall structure of FHI has remained relatively constant since 2009. FHI has reviewed the Corporate Services approach as part of this RRA. The same approach and methodologies, which were reviewed and validated by KPMG for the 2010/2011 RRA, have been used by management. FEI considers the results to be reasonable and representative of the activities and their value provided by FHI to FEI, FEVI and FEW. The increase in the fee is generally due to higher headcount in certain functions to support the businesses plus higher costs due to inflation. The higher headcount is in Internal Audit and Taxation."

77.1 Please provide a list of the internal audits performed on the FEU companies in 2009, 2010 and 2011 year to date, and provide the executive summary of any that received a less then acceptable result.

Response:

Summaries of Internal Audit reports for the years 2009 and 2010 have been provided as part of the Companies' annual reporting to the BCUC for those years. The following is a list of audit reports issued up to May 31, 2011. None of these audit reports have received a less than acceptable result.

- BCUC - Summary of IA Reports
- BCUC – Financial Directions & Orders
- FortisBC Energy – Post Implementation Review – Whistler Pipeline and Appliance Conversion Review
- FortisBC Energy - Employee Expense Report/P-Card Review
- FortisBC Energy – Energy Efficiency and Conservation Program – Process and Internal Control Review
- FortisBC Energy – Closing Group Review

78.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.18.2, pp. 272-276

Shared Services – Provision of services to Thermal Energy Services

"In Commission Order G-141-09, FEI agreed to charge Thermal Energy Services customers $0.5 million for 2010 and $0.5 million for 2011 for services provided by the gas utility. In this Application, FEI has undertaken a review of which services should be included in this administrative charge and what the charge should be for 2012 and 2013."

"Based on the review, FEI has estimated that a charge of approximately $0.5 million for both 2012 and 2013 be included as a recovery of overheads for the benefit of FEI and its ratepayers. This charge represents the expected administrative costs of supporting the AES [sic] business."

78.1 Please provide a copy of the review undertaken to support the overhead of $0.5 million.

Response:

The review undertaken was one where the FEU determined through interviews with various support departments the amount of service provided to Thermal Energy Services ("TES"). The interviews considered the direct services provided, such as office space, to more indirect services such as finance and accounts payable. Please refer to Attachment 78.1 which shows the details of the overheads for TES.

79.0 Reference: Cost of Service

Exhibit B-1, Application, Part 5.3.18.2, p. 276

Shared Services – Sharing of services with FortisBC Inc.

"In order to simplify this process between similar regulated entities, FEI is proposing to simplify the cross charges between FEU and FBC. In this Application, the FEU are requesting to allow for charges between these regulated entities to be based on a fully loaded benefits and concessions charge but to not include overheads or a facilities fee."

79.1 Please provide the total charged from FEU to FBC and from FBC to FEU in 2010 and year-to-date in 2011.

Response:

In 2010, FBC charged the FEU $208 thousand and the FEU charged FBC $98 thousand for shared services. In 2011, FBC charged the FEU $301 thousand and the FEU charged FBC $62 thousand for shared services on a year-to-date (to April 30, 2011) basis.

79.2 Please comment as to the expectation of charges for 2012 and 2013, specifically if the percentage of charges between the two companies is expected to change.

Response:

The expectation is that charges between the FEU and FBC for 2012 and 2012 will remain at the same level as in 2011. The relative percentage of charges between the two companies is not expected to be materially different than in 2011.

80.0 Reference: Cost of Service

Exhibit B-1, Application, Section 5.5.4, pp. 296-297

Allocation of Southern Crossing Pipeline Third Party Revenues

In this Application, FEU is seeking a change in the allocation between the delivery margin and midstream of the Southern Crossing Pipeline (SCP) costs and revenue, and of the Spectra Energy Kingsvale South charges related to the NWN capacity.

80.1 Please describe the allocation methodology and percentages currently used for the purposes of allocating SCP third party revenues between the delivery margin and the midstream.

Response:

NW Natural holds a long-term transportation contract for east to west service from Yahk to Huntingdon and pays approximately $9 million per year in demand charges. This total amount is credited against delivery margin.

FEI also reserves firm east to west service on SCP as part of its midstream portfolio. As a result an annual charge of $3.6 million is debited against the MCRA and an equal and offsetting amount is credited to the delivery margin.

The SCP related mitigation revenue is realized through buy/sell transactions that involve the use of SCP along with FEI's contracted capacity on Westcoast T-South and/or NGTL/Foothills and includes:

- purchasing commodity at Station 2 and selling Huntingdon;
- purchasing commodity at Station 2 and selling Kingsgate; and
- purchasing commodity at AECO and selling Huntingdon.

The allocation of T-South mitigation revenue between MCRA and delivery margin is based on the need by FEI to hold T-South capacity to flow supply on SCP to the Lower Mainland. The costs of holding the T-South Capacity are captured in the MCRA. For ease of administration the formulas below were used to determine the allocation to the MCRA and delivery margin:

Winter (November-March):

- 26 TJ Open T-South ÷ (26 TJ FEI Open T-South capacity + 113 TJ Kingsvale South Capacity) = 19% allocated to MCRA.

- The delivery margin allocation equals 100%-19%= 81%.

Summer (April-October)

- 113 TJ SCP Capacity ÷ 389 TJ T-South Capacity = 29% allocated to delivery margin.
- The MCRA allocation equals 100% - 29%= 71%.
- The following definitions apply to the above formulas:
    - Open T-South capacity refers to 26 TJ of capacity contracted in the 2010/11 ACP for Station 2 spot purchases in the winter.
    - Kingsvale South Capacity refers to 113 TJ of T-South Inland (Kingsvale) capacity that is used with SCP capacity.
    - T-South Capacity refers to 389 TJ of T-South Lower Mainland, Export and Inland (Kingsvale) capacity held by FEI in the 2010/11 ACP.

80.2 What is the total capacity, revenue and term of the T South Enhanced Service agreement with Spectra?

Response:

The total capacity of the firm transportation agreement with Spectra Energy is up to 87 MMcf/d of firm west to east on FEI's transmission system including SCP. The availability of capacity is limited by the physical capacity of FEI's 12" transmission line from Kingsvale to Oliver where it interconnects with SCP.

Revenue is forecast to be $5.7 million per year from 2011 to 2013 based on contracting the full capacity of 87 MMcf/d. However, under the agreement with Spectra the volume of contracted capacity could change from period to period which would in turn change the total amount paid by Spectra. (Note that Spectra uses this capacity to offer T-South Enhanced Service to its shippers for terms that could vary from 1 to 5 years. The volume contracted with FEI matches the volume contracted by Spectra Shippers under the T-South Enhanced Service).

The initial term of this agreement was May 1, 2010 to April 30, 2012. This agreement was recently extended to October 2014.

80.3 To what extent has the T South Enhanced Service offering been contracted for by shippers on the Spectra system?

Response:

The initial T-South Enhanced Service was fully contracted effective August 2010 through to April 2012 excluding one 10 MMcf/d contract that expires in July 2011. Spectra recently indicated that this 10 MMcf/d contract has since been recontracted by a shipper through 2014. At this time there is approximately 20 MMcf/d of T-South Enhanced Service available for contracting effective May 2012.

80.4 In the event that FEU determines it is feasible to expand the transmission system between Kingsvale and Oliver, how would the costs and benefits of the incremental capacity be allocated between the delivery margin and the midstream?

Response:

At this time, FEI is not able to provide any specifics with respect to the allocation of costs and benefits related to such an expansion of the transmission system but would seek Commission approval for the appropriate allocation of costs and benefits of the incremental capacity as part of any future application to expand the transmission system between Kingsvale and Oliver.

81.0 Reference: Rate Base

Exhibit B-1, Application, Section 5.5.4, p.297

SCP Third Party Revenues

On page 297 of the Application, FEU notes that "Any variance from the forecast net mitigation revenues of $5.7 million will be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a five year period."

81.1 On page 391 of the Application, FEU states that "Any variation from this $5.7 million and actual revenues received will be captured in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a three year period through delivery rates." Please confirm if the time period is three years or five years as stated on page 297 of the Application. Please explain the rationale for the time period whether it is three years or five years.

Response:

The SCP Mitigation Revenues Variance Account will be returned to or recovered from customers over a three-year period through delivery rates as noted on page 391 of the Application (Exhibit B-1); the reference on page 297 of the Application was incorrect.

The change to a three-year period was requested and approved through Commission Order No. G-141-09 pertaining to the 2010-2011 RRA (2010-2011 RRA, Exhibit B-1, Section C, Tab 8, page 431). The rationale for the three-year time period selected was to align the amortization period of the SCP Mitigation Revenues Variance Account with other margin related deferral accounts such as the Midstream Cost Reconciliation Account and the Revenue Stabilization Adjustment Mechanism.

81.2 Please describe how the forecast amount of $5.7 million is determined.

Response:

The $5.7 million represents forecast annual revenues received from the contracting of 87 MMcf/d of firm transportation service to Spectra to support Spectra's T-South Enhanced Service (see also the response to BCUC IR1.80.2).

81.3 Please describe the factors that would lead to variances in the forecast net mitigation revenues of $5.7 million.

Response:

The primary factor that could impact the forecast net mitigation revenues of $5.7 million would be the amount of T-South Enhanced Service under contract by Spectra's Shippers. If this service is not fully contracted, revenues would be less than the annual $5.7 million forecast at this time.

Please also refer to the response to BCUC IR 1.80.2.

82.0 Reference: Mainland SCP – Other Revenues

Exhibit B-1, Application, Part 5.2, p. 297

Other Revenues

As discussed above, FEI is seeking approval in this Application for a change in the allocation between the delivery margin and midstream of the SCP costs and revenues, and of the Spectra Energy Kingsvale South charges related to the NWN capacity. As shown in Table 5.5-6 above, the net impact to the forecast annual SCP revenues for 2012 and 2013 of this change, as compared to the approved 2011 SCP revenues, is zero because the allocation of additional costs associated with NWN related Spectra Energy Kingsvale South capacity component is offset by the allocation of an additional $3.3 million in net mitigation revenues associated with the T-South Enhanced Service.

82.1 Please explain if this change will have any impact on rates or ratepayers.

Response:

The proposed change in allocation amongst the delivery margin and midstream does not impact rates. In both the delivery margin and midstream, the change in the allocation of forecast costs is offset by the change in the allocation of forecast revenue.

82.2 Please explain if this change will have any impact on any third parties involved in transactions involving the SCP?

Response:

FEI assumes that the reference to "*any third parties in transactions involving the SCP*" contained in the question above, refers to specifically Spectra Energy and NWN. There will be no impact on any third parties involved in transactions involving the SCP.

82.3 What is the purpose of this requested change?

Response:

FEI has requested this change in order to increase transparency and allocate costs based on the principle of cost causation.

Midstream (or MCRA) customers do not have any firm rights to the NWN related Spectra Energy Kingsvale South capacity. However currently the cost of this NWN related Spectra Energy Kingsvale South capacity is allocated to the MCRA. FEI is seeking approval to allocate these costs to the delivery margin, thereby matching costs with revenues as delivery margin receives all SCP related NWN revenues.

Spectra Energy holds its own T-South capacity to deliver supply to FEI under the T-South Enhanced Service. The current SCP allocation methodology splits SCP mitigation revenue between the midstream and delivery margin because in order to mitigate SCP costs, FEI must access T-South capacity held in the MCRA. In order to generate mitigation revenues under the T-South Enhanced Service, FEI does not require the use of the MCRA held T-South capacity. As result FEI is proposing to allocate all SCP mitigation revenues associated with T-South Enhanced Service to the delivery margin.

82.4 If this change is not approved, what will be the impact on FEU and other parties involved in these SCP transactions?

Response:

If this change is not approved FEI would continue to allocate SCP mitigation revenues to delivery margin and midstream based on the methodology currently in use. FEI assumes that the term "*other parties involved in these SCP transactions*" refers to Spectra Energy and NWN. Spectra Energy and NWN are not impacted by the change in allocation of the costs and revenues within FEI between delivery margin and midstream.

82.5 Has FEI communicated this proposed change to any third parties involved in the SCP transactions and has any feedback resulting from these proposed changes been received from any third parties?

Response:

No, FEI has not communicated this proposed change to any specific third party. Third parties involved in the SCP transactions, such as NWN and Spectra Energy, will not be impacted by this change in the allocation methodology.

83.0 Reference: Property and Sundry Taxes

Exhibit B-1, Application, Section 5.6.2, pp. 300-306; Section 7, Tabs 7.1- 7.4,

Schedule 24-26

Details of Forecasted Property Taxes

Property taxes for 2012 and 2013 uses FEU's forecasts of assessed values of taxable assets, municipal mill rates, and taxes from revenues earned from natural gas consumed within Municipalities.

83.1 Please provide the assessed values used in the forecast of property taxes and complete the following table:

	2009 Actual	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast
Total Property Assessed Value (in millions)	$XXX^	$XXX^	$XXX^	$XXX^	$XXX^
Average Property Tax Rates	X.XX%*	X.XX%*	X.XX%*	X.XX%*	X.XX%*
Total (in $ millions)	$X.X**	$X.X**	$58.59	$59.96	$61.92

*Calculated (**/ ^)

** Agrees to Table 5.6-1, p. 300

Response:

The Approved 2011 FEU property taxes were incorrectly stated in Table 5.6-1 and subsequently also incorrectly referenced in Tables 5.6-2 to 5.6-5 of the Application. Revised tables are provided below which reflect the Approved 2011 property tax expense for each utility. Please note that the error was in the tables only and this change does not impact the forecast cost of service or delivery rates for 2012 and 2013 in any way.

REVISED Table 5.6-1: Property Tax Expense by Utility/Region[14]

($ thousands) Utility / Region	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland	$ 50,211.0	$ 48,858.0	$ 49,656.5	$ 51,239.0
Vancouver Island	9,564.3	9,292.1	9,895.0	10,262.5
Whistler	278.0	269.3	236.2	244.2
Fort Nelson	165.2	165.8	172.4	178.0
Total Property Taxes	**$ 60,218.5**	**$ 58,585.2**	**$ 59,960.1**	**$ 61,923.7**

REVISED Table 5.6-2: Forecast Mainland Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 17,486.0	$ 16,539.6	$ 17,889.3	$ 18,842.7
Transmission Assets	13,497.2	13,309.6	14,035.4	14,485.9
Gas Storage Assets	471.5	942.1	987.5	1,033.9
Manufactured Gas Assets	13.8	25.8	27.0	28.3
General Assets	2,479.2	2,681.9	2,804.4	2,935.3
Revenue and Other Taxes	16,263.2	15,359.0	13,912.9	13,912.9
Total Property Taxes	**$ 50,211.0**	**$ 48,858.0**	**$ 49,656.5**	**$ 51,239.0**

[14] Section 7.1 to 7.4, Schedule 25 & 26

REVISED Table 5.6-3: Forecast Vancouver Island Property Tax Expense

($ thousands) **Asset Type**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets	$ 4,700.7	$ 4,426.7	$ 4,715.6	$ 4,968.1
Transmission Assets	2,373.1	2,472.8	2,601.9	2,686.7
Gas Storage Assets	618.9	507.6	620.6	634.7
Manufactured Gas Assets	-	-	-	-
General Assets	170.4	152.4	359.1	375.1
Revenue and Other Taxes	1,701.3	1,732.6	1,597.9	1,597.9
Total Property Taxes	**$ 9,564.3**	**$ 9,292.1**	**$ 9,895.0**	**$ 10,262.5**

REVISED Table 5.6-4: Forecast Whistler Property Tax Expense

($ thousands) **Asset Type**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets	$ 118.2	$ 108.8	$ 115.9	$ 123.8
Transmission Assets	-	-	-	-
Gas Storage Assets	-	-	-	-
Manufactured Gas Assets	-	-	-	-
General Assets	-	-	-	-
Revenue and Other Taxes	159.8	160.5	120.3	120.3
Total Property Taxes	**$ 278.0**	**$ 269.3**	**$ 236.2**	**$ 244.2**

REVISED Table 5.6-5: Forecast Fort Nelson Property Tax Expense

($ thousands) **Asset Type**		**Approved** **2011**		**Projected** **2011**		**Forecast** **2012**		**Forecast** **2013**
Distribution Assets	$	94.9	$	92.1	$	99.5	$	104.4
Transmission Assets		0.3		0.3		1.3		1.3
Gas Storage Assets		-		-		-		-
Manufactured Gas Assets		-		-		-		-
General Assets		12.5		13.5		14.2		14.9
Revenue and Other Taxes		57.5		60.0		57.4		57.4
Total Property Taxes	**$**	**165.2**	**$**	**165.8**	**$**	**172.4**	**$**	**178.0**

The following requested table of assessed values used in the forecast of property taxes has been populated using the revised versions of Tables 5.6-2 through 5.6-5:

	2009 **Actual**	**2010** **Actual**	**2011** **Projected**	**2012** **Forecast**	**2013** **Forecast**
Total Property Assessed Value (in millions) ^	1,664.24	1,725.96	1,763.99	1,880.44	1,963.87
Average Property Tax Rates *	3.3%	3.4%	3.3%	3.2%	3.2%
Total (in $ millions) **	55.49	58.24	58.59	59.96	61.92

* Calculated (**/^)

83.2 Tables 5.6-2, 5.6-3, 5.6-4, and 5.6-5 show the property taxes by asset type for each utility. Please provided the assessed values used in the forecast of property taxes for each asset type by completing the following table for **each utility (FEI-Mainland shown here only as an example)**:

($millions)	**Actual 2009**	**Actual 2010**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets-assessed value^						
Property Tax Expense**			$17.46	$16.54	$17.89	$18.84
Calculated Property Tax Rate (**/^)						
Transmission Assets – assessed value^						
Property Tax Expense**			$13.30	$13.31	$14.04	$14.49
Calculated Property Tax Rate (**/^)						
Gas Storage Assets – assessed value^						
Property Tax Expense**			$0.85	$0.94	$0.99	$1.03
Calculated Property Tax Rate (**/^)						
Manufactured Gas Assets – assessed value^						
Property Tax Expense**			$0.27	$0.26	$0.27	$0.28
Calculated Property Tax Rate (**/^)						
General Assets – assessed value^						
Property Tax Expense**			$2.79	$2.68	$2.80	$2.94

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Calculated Property Tax Rate (**/^)						
Revenue and Other Taxes^						
Property Tax Expense**			$15.13	$15.36	$13.91	$13.91
Calculated Property Tax Rate (**/^)						

Response:

Please refer to BCUC IR 1.83.1 for revised tables 5.6-2 through 5.6-5, which have been updated to reflect a correction to the Approved 2011 column. For each utility, the requested table has been split into the applicable asset categories, and then the total table.

Mainland (FEI)

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets-assessed value^	786.42	831.11	855.38	830.99	890.28	937.03
Property Tax Expense**	15.79	16.56	17.49	16.54	17.89	18.84
Calculated Property Tax Rate (**/^)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Transmission Assets-assessed value^	433.56	433.06	439.38	449.71	471.81	485.72
Property Tax Expense**	12.36	12.74	13.50	13.31	14.04	14.49
Calculated Property Tax Rate (**/^)	2.9%	2.9%	3.1%	3.0%	3.0%	3.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Gas Storage Assets-assessed value^	14.04	14.61	13.42	30.00	31.24	32.54
Property Tax Expense**	0.50	0.53	0.47	0.94	0.99	1.03
Calculated Property Tax Rate (**/^)	3.6%	3.6%	3.5%	3.1%	3.2%	3.2%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Manufactured Gas Assets - assessed value^	0.39	0.57	0.38	0.57	0.58	0.60
Property Tax Expense**	0.01	0.03	0.01	0.03	0.03	0.03
Calculated Property Tax Rate (**/^)	2.6%	5.3%	2.6%	5.3%	5.2%	5.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
General Assets - assessed value^	95.17	98.81	94.52	98.57	102.49	106.58
Property Tax Expense**	2.51	2.66	2.48	2.68	2.80	2.94
Calculated Property Tax Rate (**/^)	2.6%	2.7%	2.6%	2.7%	2.7%	2.8%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Total Assets - assessed value^	1,329.59	1,378.16	1,403.08	1,409.83	1,496.41	1,562.47
Property Tax Expense**	31.17	32.52	33.95	33.50	35.74	37.33
Calculated Property Tax Rate (**/^)	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%

Vancouver Island (FEVI)

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets-assessed value^	231.65	238.86	248.69	233.85	248.37	261.42
Property Tax Expense**	4.32	4.51	4.70	4.43	4.71	4.97
Calculated Property Tax Rate (**/^)	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Transmission Assets-assessed value^	82.53	82.07	81.63	83.31	87.22	89.84
Property Tax Expense**	2.45	2.42	2.37	2.47	2.60	2.69
Calculated Property Tax Rate (**/^)	3.0%	2.9%	2.9%	3.0%	3.0%	3.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Gas Storage Assets-assessed value^	2.59	11.97	27.93	20.56	25.00	25.53
Property Tax Expense**	0.04	0.29	0.62	0.51	0.62	0.63
Calculated Property Tax Rate (**/^)	1.5%	2.4%	2.2%	2.5%	2.5%	2.5%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
General Assets - assessed value^	3.25	3.97	5.62	5.60	11.87	12.33
Property Tax Expense**	0.11	0.12	0.17	0.15	0.36	0.38
Calculated Property Tax Rate (**/^)	3.4%	3.0%	3.0%	2.7%	3.0%	3.1%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Total Assets - assessed value^	320.02	336.87	363.87	343.32	372.46	389.12
Property Tax Expense**	6.92	7.34	7.86	7.56	8.29	8.67
Calculated Property Tax Rate (**/^)	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%

Whistler (FEW)

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets-assessed value^	6.82	7.29	6.99	7.11	7.56	8.03
Property Tax Expense**	0.10	0.11	0.11	0.11	0.12	0.12
Calculated Property Tax Rate (**/^)	1.5%	1.5%	1.6%	1.5%	1.6%	1.5%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Manufactured Gas Assets - assessed value^	4.33	-	-	-	-	-
Property Tax Expense**	0.12	-	-	-	-	-
Calculated Property Tax Rate (**/^)	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Total Assets - assessed value^	11.15	7.29	6.99	7.11	7.56	8.03
Property Tax Expense**	0.22	0.11	0.11	0.11	0.12	0.12
Calculated Property Tax Rate (**/^)	2.0%	1.5%	1.6%	1.5%	1.6%	1.5%

Fort Nelson

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets-assessed value^	3.17	3.25	3.31	3.28	3.54	3.72
Property Tax Expense**	0.09	0.09	0.09	0.09	0.10	0.10
Calculated Property Tax Rate (**/^)	2.8%	2.8%	2.7%	2.7%	2.8%	2.7%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Transmission Assets-assessed value^	-	0.01	0.03	0.01	0.01	0.06
Property Tax Expense**	-	-	-	-	-	-
Calculated Property Tax Rate (**/^)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
General Assets - assessed value^	0.31	0.37	0.41	0.44	0.46	0.48
Property Tax Expense**	0.01	0.01	0.01	0.01	0.01	0.01
Calculated Property Tax Rate (/^)**	3.2%	2.7%	2.4%	2.3%	2.2%	2.1%

($millions)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Total Assets - assessed value^	3.48	3.64	3.75	3.73	4.01	4.25
Property Tax Expense**	0.10	0.10	0.11	0.11	0.11	0.12
Calculated Property Tax Rate (/^)**	2.9%	2.7%	2.9%	2.9%	2.7%	2.8%

A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. For all municipalities, except the City of Vancouver, the utility pays a tax of 1 percent of revenues in the second preceding year. For the City of Vancouver, the utility pays 1.25 percent of revenues earned in the preceding year.

83.3 Please complete the following table for FEW, FEVI and Fort Nelson each **(FEVI shown here only as an example)** and provide explanations for any differences:

	2009 Actual				**2011 Projected**		**2012 Forecast**		**2013 Forecast**	
Corporate Revenues from gas consumed (in millions)	2006	$*	2008	$*	2009	$*	2010	$*	2011	$*
A: Calculated Revenue and Other Taxes Component of Property Tax (*x 1%)										
B: Corporate Revenues from gas consumed x 1% = Corporate Revenue component of Property Tax (in millions)					$1.73**		$1.60**		$1.60**	
Difference (A-B)										

**Agrees to Table 5.6-3, p. 302

Response:

The requested tables are provided below for Vancouver Island, Whistler and Fort Nelson. In these tables, rows D and E equal the Total Revenue and Other Taxes amounts in the revised version of Tables 5.6-3 through 5.6-5 as provided in the response to BCUC IR 1.83.1. An additional reconciliation to line 3, of Schedules 24 and 25 of Section 7.2, Section 7.3 and Section 7.4 follows each table:

Vancouver Island

In millions	Actual 2009		Actual 2010		Approved 2011		Projected 2011		Forecast 2012		Forecast 2013	
A: Corporate Revenues from gas consumed	2007	155.17	2008	164.27	2009	165.52	2009	168.36	2010	154.89	2011	154.89
B: Revenue Component of Property Tax (A1 x 1.0%)		1.55		1.64		1.66		1.68		1.55		1.55
C: Other Taxes (OGC Fees)		0.02		0.05		0.05		0.05		0.05		0.05
D: Total Calculated Revenue and Other Taxes		1.57		1.69		1.71		1.73		1.60		1.60
E: Corporate Revenue Component of Property Tax (in millions) Schedule 24 -26		1.57		1.69		1.71		1.73		1.60		1.60
F: Difference (D-E)		-		-		-		-		-		-

FEVI Reconcilation of Revenue and Other Taxes	**2010 Actual**	**2011 Approved**	**2011 Projected**	**2012 Forecast**	**2013 Forecast**
1% in Lieu Revenue Component per Line 3, Schedule 24-26	1.64	1.66	1.68	1.55	1.55
Other taxes embedded in Line 5, Schedule 24-26	0.05	0.05	0.05	0.05	0.05
Total Revenue and Other Taxes per Schedule 24-26	1.69	1.71	1.73	1.60	1.60
Total Revenue and Other Taxes per BCUC IR 1.83.3	1.69	1.71	1.73	1.60	1.60
Variance	-	-	-	-	-

Whistler

In millions	Actual 2009		Actual 2010		Approved 2011		Projected 2011		Forecast 2012		Forecast 2013	
A: Corporate Revenues from gas consumed	2007	14.95	2008	17.04	2009	15.98	2009	16.05	2010	12.03	2011	12.03
B: Revenue Component of Property Tax		0.15		0.17		0.16		0.16		0.12		0.12
C: Other Taxes (OGC Fees)		-		-		-		-		-		-
D: Total Revenue and Other Taxes		0.15		0.17		0.16		0.16		0.12		0.12
E: Corporate Revenue Component of Property Tax (in millions) per Schedule 24-26		0.15		0.17		0.16		0.16		0.12		0.12
F: Difference (D-E)		-		-		-		-		-		-

FEW Reconcilation of Revenue and Other Taxes	**2010 Actual**	**2011 Approved**	**2011 Projected**	**2012 Forecast**	**2013 Forecast**
1% in Lieu Revenue Component per Line 3, Schedule 24-26	0.17	0.16	0.16	0.12	0.12
Other taxes embedded in Line 5, Schedule 24-26	-	-	-	-	-
Total Revenue and Other Taxes per Schedule 24-26	0.17	0.16	0.16	0.12	0.12
Total Revenue and Other Taxes per BCUC IR 1.83.3	0.17	0.16	0.16	0.12	0.12
Variance	-	-	-	-	-

Fort Nelson

In millions	Actual 2009		Actual 2010		Approved 2011		Projected 2011		Forecast 2012		Forecast 2013	
A: Corporate Revenues from gas consumed	2007	3.82	2008	5.50	2009	5.75	2009	5.75	2010	6.05	2011	5.69
B: Revenue Component of Property Tax (A1 x 1.0%)		0.04		0.06		0.06		0.06		0.06		0.06
C: Other Taxes (OGC Fees)		-		-		-		-		-		-
D: Total Revenue and Other Taxes		0.04		0.06		0.06		0.06		0.06		0.06
E: Corporate Revenue Component of Property Tax (in millions) per Schedule 24-26		0.04		0.06		0.06		0.06		0.06		0.06
F: Difference (D-E)		-		-		-		-		-		-

Fort Nelson Reconcilation of Revenue and Other Taxes	2010 Actual	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
1% in Lieu Revenue Component per Line 3, Schedule 24-26	0.06	0.06	0.06	0.06	0.06
Other taxes embedded in Line 5, Schedule 24-26	-	-	-	-	-
Total Revenue and Other Taxes per Schedule 24-26	0.06	0.06	0.06	0.06	0.06
Total Revenue and Other Taxes per BCUC IR 1.83.3	0.06	0.06	0.06	0.06	0.06
Variance	-	-	-	-	-

83.4 Please complete the following table for FEI-Mainland and provide explanations for any differences:

	2009 Actual		2010 Actual		2011 Projected		2012 Forecast		2013 Forecast	
Corporate Revenues from gas consumed (in millions)	2008	$*	2009	$*	2010	$*	2011	$*	2012	$*
A: Calculated Revenue and Other Taxes Component of Property Tax (*x 1.25%)										
B: Corporate Revenues from gas consumed x 1.25% = Corporate Revenue component of Property Tax (in millions)					$15.36**		$13.91**		$13.91**	
Difference (A-B)										

Response:

The requested table is provided below for Mainland. In this table, rows D and E equal the Total Revenue and Other Taxes amounts in the revised version of Table 5.6-2 as provided in the response to BCUC IR 1.83.1. An additional reconciliation to line 3, of Schedules 24 and 25 of Section 7.1 follows the table:

In millions	Actual 2009		Actual 2010		Approved 2011		Projected 2011		Forecast 2012		Forecast 2013	
A1: Corporate Revenues from gas consumed - All Municipalites except Vancovuer (in $)	2007	1,177.59	2008	12.95	2009	1,266.83	2009	1,203.70	2010	1,059.83	2011	1,059.83
A2: Corporate Revenues from gas consumed - Vancouver only (in $)	2008	276.70	2009	250.36	2010	271.86	2010	250.96	2011	312.95	2012	312.95
A3: Total Calculated Corporate Revenues from gas consumed (A1 + A2)		15.23		263.29		1,538.69		1,454.66		1,372.785		1,372.785
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)		-		-		-		-		-		-

FEI Reconcilation of Revenue and Other Taxes	2010 Actual	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
1% in Lieu Revenue Component per Line 3, Schedule 24-26	16.05	16.07	15.17	13.73	13.73
Other taxes embedded in Line 5, Schedule 24-26	0.18	0.20	0.19	0.19	0.19
Total Revenue and Other Taxes per Schedule 24-26	16.23	16.27	15.36	13.91	13.91
Total Revenue and Other Taxes per BCUC IR 1.83.4	16.23	16.27	15.36	13.92	13.91
Variance[1]	-	-	-	(0.01)	-

[1] *A 0.01 rounding variance exists in 2012*

Please note the following:

1. Revenues for actual 2009, actual 2010 and projected 2011 reflect actual revenues reported to municipalities as required under Section 353 of the Local Government Act and Section 398 of the Vancouver Charter. Taxes payable under Section 398 of the Vancouver Charter are shown separately in the table above as they require payment at 1.25% rather than 1% as required under the Local Government Act.

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%

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.

83.5 FEVI has stated on p.303 in point #4 that the Langford regional operations centre is not taxable in 2011 as it is not expected to complete until April 2011.

Please provide an explanation why it would not be taxable in the year that it is complete.

Response:

Property taxes payable in 2011 uses property values that are to reflect market conditions at July 1 of the previous year (2010), but based on the state and condition of the property at October 31 of that same year. In the case of the Langford Regional Operations Centre, only land was taxable in 2011 as construction had not commenced in 2010.

FEW stated on p. 304 in point #1 that FEW was successful on an appeal in 2011 that resulted in lower assessment values and therefore 2011 projected property taxes are lower than the amounts projected.

83.6 Please confirm if the lower assessment value is factored into the forecast for 2012 and 2013.

Response:

Confirmed. The lower assessment values were factored into the forecasts for 2012 and 2013.

84.0 Reference: Financing Costs and Return on Equity

Exhibit B-1, Application, Section 5.7, p. 309

Equity Component of FEVI and FEW

This section (see Section 5.7.2) also explains why the Companies are seeking Commission's permission to defer the filing of evidence with respect to FEVI and FEW's equity component as directed in Directive No. 7 of Commission Order G-158-09. As discussed in this section, given FEU's plans to file an application in Fall 2011 to Amalgamate the Companies, FEU believes that it is more efficient to defer the filing of the evidence until that time.

84.1 FEU is seeking permission to defer the filing of evidence with respect to FEVI and FEW's equity component, which is a requirement under Commission Order G-158-09. Although it may be more efficient to do this in the event amalgamation is approved in the future, how will the FEU (and FEW and FEVI) address any differences in the equity component of FEVI and FEW's capital structure if application for amalgamation is not approved, as it relates to this current RRA and the rate changes being requested?

Response:

As noted in the preamble above, the FEU is seeking to defer the filing of evidence until Fall 2011, as part of the amalgamation application. The FEU will put forth evidence related to capital structure for both the amalgamated FEU, should amalgamation be accepted, and the standalone FEVI and FEW, should amalgamation be rejected.

The Companies' evidence of stand-alone capital structures will support a higher equity thickness for FEVI and FEW. However, in the event amalgamation is rejected, FEVI and FEW are prepared not to seek to have the increase in equity thickness implemented until after 2013 in order to facilitate a negotiated settlement of the revenue requirements.

84.2 If amalgamation is approved and there are differences in the equity component of FEVI and FEW, how will the FEU (and FEW and FEVI) address the impact of these differences on the 2012 rates before the implementation of the proposed amalgamation and harmonized rates in 2013?

Response:

If amalgamation is approved, it would not take effect until 2013, please refer to BCUC IR 1.84.1. As such, the FEU do not propose or intend to apply to change the capital structure during 2012 such that it would impact 2012 rates. The impact of amalgamation (lower borrowing costs) would only come into effect post amalgamation and would only impact amalgamated rates starting in 2013.

As noted in the response to BCUC IR 1.84.1, in the event amalgamation is not approved and the Commission approves different capital structures for FEVI and FEW, the FEU expect that the new capital structures would take effect after 2013.

85.0 Reference: Rate Base Overview and Summary by Utility/Region

Exhibit B-1, Application, Section 6.1, pp. 317-323; Section 7, Tabs 7.1-7.4, Schedule 42

Capital Expenditures and Plant Additions for Capital Projects and CPCN's

The increase in rate base for FEI-Mainland is primarily attributable to investments in system sustainment and reliability and the addition of assets related to the CPCN Projects – Customer Care Enhancement, Fraser River Crossing Seismic Upgrade, and Kootenay River Crossing; for FEVI is primarily related to the full impact of the CPCN Project - Hayes LNG Facility; for FEW is primarily related to the CPCN Project – Customer Care Enhancement; and for Fort Nelson is primarily related to the full impact of the Muskawa River Crossing Project.

85.1 Schedule 42 summarizes the forecasted capital expenditures for each project, however, does not provide information on the status of costs incurred to date in relation to the approved budget for the projects under their respective CPCN's or to budget for non-CPCN projects. Please complete Attachment 2 to this document which is a modified schedule 42 for each of the FEU utilities. (Note that the attached modified schedule only shows FEI-Mainland but should be prepared for all utilities)

Response:

Please refer to Attachment 85.1 for the completed schedule as requested. The FEU have identified some minor changes to reflect refinements in the timing of expenditures which impact the CPCN expenditure for the year, work in progress balances and AFUDC as originally shown in the Application (Exhibit B-1) on Schedule 42 of Tabs 7.1-7.4. These changes do not impact the total overall project costs nor do they impact the projected or forecast total plant additions.

Schedule 42 of Tabs 7.1-7.4 will be amended reflecting the revised amounts as provided in Attachment 85.1, and provided when Evidentiary Updates are filed.

86.0 Reference: Gross Plant in Service

Exhibit B-1, Application, Section 6.1.5.1, pp.321-324; Section 7, Tabs 7.1 to 7.4, Schedules 36-38 and schedules42-51

Plant Additions and Retirements

The FEU forecasts retirements based on a percentage of additions each year, which is based on a five year historical average for all classes except those subject to amortization accounting.

86.1 Please provide analysis of five year historical average for all classes except those subject to amortization accounting.

<u>Response:</u>

Excluding those asset classes subject to amortization accounting, the table below contains all other assets with recorded retirements during the period 2006 – 2010.

Asset Class	2006 Additions	2006 Retirements	2007 Additions	2007 Retirements	2008 Additions	2008 Retirements	2009 Additions	2009 Retirements	2010 Additions	2010 Retirements	Total Additions	Total Retirements	Average
FEI													
449-00 Local Storage Equipment (Tilbury)	216	(112)	263	(196)	2,955	(1,298)	1,171	(82)	479	0	5,085	(1,688)	33.2%
465-00 Mains	6,482	(388)	4,236	(77)	7,999	(67)	5,599	(685)	7,647	(321)	31,963	(1,538)	4.8%
466-00 Compressor Equipment	33	(16)	15	0	308	(63)	175	0	3,359	(450)	3,890	(528)	13.6%
467-20 Telemetering	862	(1,511)	1,070	(237)	616	(27)	259	(176)	288	(69)	3,095	(2,019)	65.3%
473-00 Services	18,074	(9,990)	24,197	(2,936)	21,585	(3,694)	16,440	(4,274)	17,475	(2,956)	97,771	(23,851)	24.4%
474-00 House Regulators and Meter Installations	7,174	(7,604)	7,609	(4,762)	6,307	(6,986)	8,017	(7,331)	10,731	(17,526)	39,837	(44,210)	111.0%
475-00 Mains	19,611	(2,028)	12,510	(1,497)	18,609	(2,444)	19,977	(3,349)	13,260	(969)	83,967	(10,287)	12.3%
477-00 Measuring & Regulating Equipment	5,407	(971)	3,996	(427)	2,436	(905)	2,210	(567)	2,842	(256)	16,891	(3,126)	18.5%
478-00 Meters	8,521	(3,815)	9,368	(3,247)	8,000	(4,774)	8,628	(4,140)	8,305	(6,433)	42,821	(22,410)	52.3%
482-00 Structures & Improvements	2,008	(191)	2,969	(1,680)	1,093	(2,006)	1,685	(317)	2,731	0	10,486	(4,194)	40.0%
484-00 Vehicles	41	(7)	11	(93)	177	(40)	157	(33)	502	(7)	889	(180)	20.3%
485-10 Heavy/Mobile Work Equipment	26	(70)	10	(0)	131	0	80	0	423	0	670	(70)	10.5%
FEVI													
467-10 Measuring & Regulating Equipment	641	0	737	(412)	494	(131)	127	(61)	184	(669)	2,183	(1,273)	58.3%
473-00 Services	6,196	0	6,167	(3)	8,869	(675)	6,839	(285)	8,272	(198)	36,342	(1,162)	3.2%
475-00 Mains	4,679	0	8,997	35	8,414	(179)	4,347	(155)	4,155	(90)	30,592	(389)	1.3%
477-00 Measuring & Regulating Equipment	142	0	180	(48)	40	(80)	538	0	520	(0)	1,420	(128)	9.0%
478-00 Meters	401	0	657	0	240	0	374	0	188	0	1,859	0	0.0%
482-00 Structures & Improvements	70	0	74	(12)	322	0	489	(952)	207	0	1,161	(963)	83.0%
484-00 Vehicles	833	(981)	435	(685)	752	(198)	499	(370)	521	(163)	3,040	(2,397)	78.8%
485-10 Heavy/Mobile Work Equipment	63	(94)	158	(35)	96	(84)	393	0	274	(12)	984	(226)	23.0%
FEW													
473-00 Services	191	0	848	(5)	203	(7)	485	(10)	192	(3)	1,919	(25)	1.3%
475-00 Mains	59	0	(49)	(3)	63	(5)	1,612	(0)	343	(147)	2,027	(156)	7.7%
478-00 Meters	6	0	27	0	0	0	(48)	0	19	0	3	0	0.0%
482-00 Structures & Improvements	0	0	0	0	0	0	0	0	14	(5)	14	(5)	34.9%
484-00 Vehicles	17	0	0	(111)	54	0	53	0	0	0	125	(111)	88.8%

To clarify the methodology of forecasting plant retirements, the following is an overview of the basis used for forecasting of 2012 / 2013 retirements for all of FEU`s asset classes.

Transmission and Distribution Assets:

Most of the Transmission (44X, 46X) and Distribution (47X) asset classes retirements listed are based on a historical percentage of additions methodology, with the exceptions being service and meter retirements.

Services and Meters:

For 2012 and 2013, services and meter forecast retirements are based on the level of forecasted abandonments and meter retirements respectively. In the past, services and meter retirements were forecasted using the historical percentage of additions methodology. For its 2011 Mains and Services retirement projections, instead of using the historical percentage methodology, the projected amounts are based on recent year's experience which is more refined.

Meter Installations and Regulators:

Forecast retirements are based on the proposed adoption of amortization accounting where retirements are forecast at the time the assets becomes fully amortized.

General Plant:

Amortization Accounting Applied

Within the General Plant classification, some of the asset classes, 483 Computer Hardware / Software, 483 Office Equipment and Furniture, 486 Tools and Equipment, 487 NGV Cylinders, 488 Telephone and Radio Equipment are subject to amortization accounting. As a result, retirements for these asset classes are forecast at the time the asset becomes fully amortized.

No Amortization Accounting Applied

General plant asset classes where the assets are individually tracked and not subject to amortization accounting include building structures, vehicles, and heavy work/mobile equipment. Retirements for these asset classes are based on forecasted known retirements or in the case of vehicles using a percentage of historical additions.

86.2 Please provide a schedule showing estimated provisions for the last 5 years (2007-2011) compared to actual retirements to demonstrate how effective this estimation process is.

Response:

The FEU have provided schedules for each utility showing the estimated compared to actual retirements for the last five years.

For FEI, from 2007 to 2009, the estimated retirements were determined using a percentage of formula additions approach in accordance with the PBR agreement. The use of this approach, with a starting base in 2003, did not allow for the estimated retirements to be updated for current assumptions. Updating the estimates would have reduced the actual to forecast differences significantly.

For FEI, for 2010, the total retirements of $53 million were relatively close to the estimate of $48 million. In 2011, which is on a projected basis, the difference between the total estimate and the projection is primarily in the services, meters and meter installations asset classes, with lower anticipated retirements in these respective areas.

For FEVI, over the five years, actual retirements were relatively close to the estimates with the only significant variance in 2010 where a larger amount of office equipment was retired. These retirements were necessary to transition towards the adoption of the amortization accounting approach approved for 2010 for specific general plant asset classes.

For FEW, over the five years, actual retirements were relatively close to estimates with variances in 2009/2010/2011 years due to the difference in the timing of the asset retirements resulting from the conversion of the propane system to natural gas.

The FEU note that the forecast amount of retirements does not affect the determination of rate base, as the same amount of retirements are forecast for plant additions and for accumulated depreciation. The impact of retirements is limited to its impact on depreciation expense for the test period only. For example, in those years where retirement forecasts were greater than actual, all else equal, depreciation expense was lower than actual.

FEI Retirements

Asset Classes	2007 Estimate	2007 Actual	2008 Estimate	2008 Actual	2009 Estimate	2009 Actual	2010 Estimate	2010 Actual	2011 Estimate	2011 Projection
402-00 Other Intangible Plant				(85)						
402-01 Application Software - 12.5%					(8,983)	(15,430)	(8,954)	(8,365)	(10,840)	(11,301)
402-02 Application Software - 20%					(1,473)	(344)	(1,847)	(2,527)	(1,147)	(91)
TOTAL INTANGIBLE PLANT	0	0	0	(85)	(10,456)	(15,774)	(10,801)	(10,892)	(11,987)	(11,392)
442-00 Structures & Improvements (Tilbury)		(16)		(6)						
443-00 Gas Holders - Storage (Tilbury)		(80)		(2)						
449-00 Local Storage Equipment (Tilbury)		(196)		(1,298)		(82)				(709)
TOTAL MANUFACTURED GAS / LOCAL STORAGE	0	(292)	0	(1,306)	0	(82)	0	0	0	(709)
460-00 Land in Fee Simple								(1)		
462-00 Compressor Structures		4		(13)		(40)				
463-00 Measuring Structures		(41)				(1)				
464-00 Other Structures & Improvements						(12)				
465-00 Mains	(174)	(77)	(180)	(67)	(184)	(685)	(998)	(321)	(1,367)	
466-00 Compressor Equipment				(63)						
466-00 Compressor Equipment - OVERHAUL								(450)		
467-00 Measuring & Regulating Equipment		(237)		(27)		(176)		(69)		
TOTAL TRANSMISSION PLANT	(174)	(351)	(180)	(170)	(184)	(914)	(998)	(841)	(1,367)	0
470-00 Land in Fee Simple				(5)						
472-00 Structures & Improvements		(19)		(80)		(35)		(3)		
473-00 Services	(3,932)	(2,936)	(3,150)	(3,694)	(3,042)	(4,274)	(6,579)	(2,956)	(6,966)	(3,687)
473-00 Services - LILO										(77)
474-00 House Regulators & Meter Installations	(516)	(4,762)	(509)	(6,986)	(516)	(7,331)	(9,614)	(17,526)	(10,098)	
475-00 Mains	(3,570)	(1,497)	(3,351)	(2,444)	(3,367)	(3,349)	(1,979)	(969)	(1,983)	(1,021)
475-00 Mains - LILO										(47)
477-00 Measuring & Regulating Equipment	(540)	(427)	(555)	(905)	(570)	(567)	(714)	(256)	(716)	
477-00 Telemetering	(8)		(8)		(8)		(11)		(11)	
478-10 Meters	(605)	(3,247)	(575)	(4,774)	(580)	(4,140)	(7,869)	(6,433)	(8,277)	(3,827)
TOTAL DISTRIBUTION PLANT	(9,171)	(12,888)	(8,148)	(18,888)	(8,083)	(19,696)	(26,766)	(28,143)	(28,051)	(8,659)
480-00 Land in Fee Simple		(1,136)								
482-00 Structures & Improvements		(1,680)		(2,006)		(317)				
- Frame Buildings										(6)
483-30 GP Office Equipment	(39)	(39)	(1,264)	(1,219)	(90)	(89)	(90)	(1,077)	(991)	
483-40 GP Furniture							(5)		(1,230)	(1,462)
483-10 GP Computer Hardware	(8,750)	(12,727)	(755)	(753)	(8,956)	(3,559)	(6,245)	(7,466)		
483-20 GP Computer Software	(7,624)	(7,208)	(14,215)	(4,564)			(20)		(198)	(198)
483-21 GP Computer Software	(7,208)	(7,586)	(4,564)	(14,291)		6		(20)		
484-00 Vehicles		(93)		(40)		(33)		(7)		(424)
484-00 Vehicles - Leased							(2,321)	(2,107)	(1,641)	(2,226)
486-00 Small Tools & Equipment	(167)	(159)	(2,346)	(2,179)	(327)	(326)				(1,806)
487-00 Equipment on Customer's Premises		(1,812)								
- Telephone	(2)		(45)		(10)		(202)		(1,596)	(1)
- Radio	(545)	(517)	(419)	(243)	(529)	(584)		(3,223)	(954)	(952)
489-00 Other General Equipment										
TOTAL GENERAL PLANT & EQUIPMENT	(24,335)	(32,957)	(23,608)	(25,295)	(9,912)	(4,902)	(8,883)	(13,900)	(6,610)	(7,075)
499 Plant Suspense		(24)								
TOTAL UNCLASSIFIED PLANT	0	(24)	0	0	0	0	0	0	0	0
Total	(33,680)	(46,514)	(31,936)	(45,745)	(28,635)	(41,368)	(47,448)	(53,778)	(48,015)	(27,835)

Note 1: Figures as provided in the Annual Reviews, Annual Reports and RRA Filings.

Vancouver Island Retirements

Asset Classes	2007 Estimate	2007 Actual	2008 Estimate	2008 Actual	2009 Estimate	2009 Actual	2010 Estimate	2010 Actual	2011 Estimate	2011 Projection
402-01 Application Software - 12.5%						(47)	(91)	(431)	(340)	
TOTAL INTANGIBLE PLANT	0	0	0	0	0	(47)	(91)	(431)	(340)	0
463-00 Measuring Structures								(220)		
465-00 Mains				(1)		(5)				
466-00 Compressor Equipment				(5)						
467-00 Measuring & Regulating Equipment	(200)	(412)		(131)		(61)		(669)		(58)
468-00 Communication Structures & Equipment				(18)				(33)		
TOTAL TRANSMISSION PLANT	(200)	(412)	0	(154)	0	(66)	0	(921)	0	(58)
473-00 Services	(254)	(3)	(675)	(675)	(409)	(285)	(357)	(198)	(379)	(159)
474-00 House Regulators & Meter Installations	(42)				(77)		(56)		(56)	
475-00 Mains	(344)	35	(179)	(179)	(300)	(155)	(239)	(90)	(294)	(69)
477-00 Measuring & Regulating Equipment		(48)	(4)	(80)				(0)		(27)
478-10 Meters	(28)				(42)		(51)		(52)	(312)
TOTAL DISTRIBUTION PLANT	(668)	(16)	(858)	(935)	(829)	(440)	(703)	(288)	(781)	(567)
482-00 Structures & Improvements	(12)	(12)				(952)				
- Leasehold Improvement										(1)
483-30 GP Office Equipment							(897)	(1,626)	(729)	
483-10 GP Computer Hardware							(192)	(961)	(175)	
483-20 GP Computer Software		(0)			(47)					
484-00 Vehicles	(243)	(685)	(148)	(198)		(370)	(52)	(163)	(162)	(341)
485-10 Heavy Work Equipment		(35)	(24)	(84)				(12)	(32)	(34)
486-00 Small Tools & Equipment									(210)	(210)
487-00 Equipment on Customer's Premises	(4,928)	(4,928)								
488-00 Communications Equipment	(4)	(74)	(127)	(127)	(230)	(371)				
- Telephone							(160)	(22)	(22)	(156)
TOTAL GENERAL PLANT & EQUIPMENT	(5,187)	(5,734)	(299)	(410)	(277)	(1,693)	(1,301)	(2,784)	(1,330)	(742)
Total	(6,055)	(6,162)	(1,157)	(1,499)	(1,106)	(2,245)	(2,095)	(4,424)	(2,451)	(1,367)

Note 2: Figures as provided in the Annual Reports, Negotiated Settlements and RRA Filings.

Whistler Retirements

Asset Classes	2007 Estimate	2007 Actual	2008 Estimate	2008 Actual	2009 Estimate	2009 Actual	2010 Estimate	2010 Actual	2011 Estimate	2011 Projection
461-00 Transmission Land Rights							(4)			
TOTAL INTANGIBLE PLANT	0	0	0	0	0	0	(4)	0	0	0
430-00 Manufact'd Gas - Land							(899)			(899)
431-00 Manufact'd Gas - Land Rights		(0)				(4)				
432-00 Manufact'd Gas - Struct. & Improvements						(2,879)	(2,879)			
433-00 Manufact'd Gas - Equipment						(1,695)	(1,695)			
434-00 Manufact'd Gas - Gas Holders						(2,070)	(2,070)			
436-00 Manufact'd Gas - Compressor Equipment						(38)	(38)			
437-00 Manufact'd Gas - Measuring & Regulating Equipment						(344)	(344)			
443-00 Gas Holders - Storage						(38)	(38)			
TOTAL MANUFACTURED GAS / LOCAL STORAGE	0	(0)	0	0	0	(7,067)	(7,962)	0	0	(899)
472-00 Structures & Improvements								(0)		
473-00 Services		(5)		(7)	(18)	(10)	(5)	(3)	(5)	(1)
475-00 Mains		(3)		(5)		(0)		(147)		(19)
477-00 Measuring & Regulating Equipment								(22)		
478-10 Meters										(12)
TOTAL DISTRIBUTION PLANT	0	(8)	0	(12)	(18)	(10)	(5)	(172)	(5)	(32)
482-00 Structures & Improvements								(5)		
Office Equipment & Furniture								(12)		
483-30 GP Office Equipment									(3)	
483-10 GP Computer Hardware		(13)								
483-20 GP Computer Software		(6)								
484-00 Vehicles		(111)								
485-10 Heavy Work Equipment									(3)	(3)
486-00 Small Tools & Equipment							(2)	(2)	(11)	(11)
- Telephone								(30)	(26)	
TOTAL GENERAL PLANT & EQUIPMENT	0	(129)	0	0	0	0	(2)	(49)	(44)	(14)
Total	0	(137)	0	(12)	(18)	(7,077)	(7,972)	(222)	(48)	(945)

Note 3: 2007 and 2008 estimates not available as no RRA was filed in those years.

Ft Nelson Retirements

Asset Classes	2007 Estimate	2007 Actual	2008 Estimate	2008 Actual	2009 Estimate	2009 Actual	2010 Estimate	2010 Actual	2011 Estimate	2011 Projection
463-00 Measuring Structures						(3)				
464-00 Other Structures & Improvements		(7)								
465-00 Mains						(8)			(29)	(29)
467-00 Measuring & Regulating Equipment						(63)		(1)		
TOTAL TRANSMISSION PLANT	0	(7)	0	0	0	(74)	0	(1)	(29)	(29)
473-00 Services		(4)		(8)		(45)	0	(14)		(16)
474-00 House Regulators & Meter Installations		(8)		(25)		(18)		(134)		
475-00 Mains						(2)		(6)		
477-00 Measuring & Regulating Equipment		(10)		(2)		(9)		(2)		
478-10 Meters		(1)		(8)		(4)		0		
TOTAL DISTRIBUTION PLANT	0	(23)	0	(43)	0	(78)	0	(157)	0	(16)
482-00 Structures & Improvements										
- Masonry Buildings										(146)
483-30 GP Office Equipment								(3)		
483-20 GP Computer Software		(52)		(1)		(6)				
486-00 Small Tools & Equipment		(8)		(1)	(1)	(1)				
487-00 Equipment on Customer's Premises										(15)
488-00 Communications Equipment		(3)								
- Radio										(2)
TOTAL GENERAL PLANT & EQUIPMENT	0	(64)	0	(2)	(1)	(7)	0	(3)	0	(163)
Total	0	(94)	0	(45)	(1)	(158)	0	(160)	(29)	(208)

Note 4: 2007, 2008 and 2010 estimates not available as no RRA was filed. Please refer to BCUC IR No. 1.86.4 for a description of the building retirement projection in 2011.

86.3 Please provide support for the determination of forecasted retirements for FEI-Mainland in Section 7, Tab 7.1, Schedules 43-51, as follows:

86.3.1 Schedule 43 – please provide calculation and support for projected 2011 retirements related to the following (support for all questions should include either

86.3.2 i) the calculated performed, or where amounts are determined based on actual assets, a listing of assets retired

86.3.3 ii) confirmation that the asset is forecast to no longer be in use, original asset cost, estimated removal cost and gain/loss on retirement):

402-01 Application Software – 12.5 percent	$11,301,000

Response:

The FEU interpret BCUC IRs 1.86.3.1, 1.86.3.2 and 1.86.3.3 as pertaining to Asset Class 402-01.

2011 projected and 2012/2013 forecast retirements for asset class 402-01 Application Software – 12.5 percent are based on the approved amortization accounting approach where assets are retired at their end of their estimated life, with no gains/losses recorded. The forecast amount of $11.3 million in 2011 represents those Application software assets forecast to be fully depreciated and no longer in use.

86.3.4 Schedule 44 – please provide calculation/support for projected 2011 retirements related to:

473-00 Services	$3,687,000
475-00 Mains	$1,021,000
478-10 Meters	$3,827,000

Response:

The projected retirements for the Services and Mains categories above are based on the recent year's experience. The 473-00 Services projection is based on the retirement of 119,915 metres of services at an average cost of $30.75 per metre. The 475-00 Mains projection is based on the retirement of 35,781 metres of Main at an average cost of $28.53 per metre.

The 478-10 Meters projection is based on expected meter retirements of 37,875 residential and 390 industrial meter retirements at an average cost per meter of $100.

Please also refer to the response to BCUC IR 1.86.1 for a description of the asset retirement forecast process.

86.3.5 Schedule 45 – please provide calculation/support for projected 2011 retirements related to:

483-40 GP Furniture	$1,462,000
484-00 Vehicles – Leased	$2,226,000
486-00 Small Tools & Equipment	$1,806,000

Response:

Projected 2011 and forecast 2012/2013 retirements for asset class 483-40 GP Furniture and 486-00 Small Tools & Equipment are based on the approved amortization accounting approach where assets are retired at their end of their estimated life, with no gains/losses recorded. The forecasted amounts for asset classes 483-40 and 486-00 represent assets forecast to be fully depreciated and no longer in use.

Projected retirement for asset class 484-00 Vehicles – Leased in 2011 have been calculated as a percentage of anticipated vehicle additions. In 2011, approximately $2.2 million in retirements are projected based on 60 percent of estimated additions of $3.7 million.

86.3.6 Schedule 46 – please provide calculation/support for forecasted 2012 retirements related to:

402-01 Application Software – 12.5%	$2,722,000
402-02 Application Software – 20%	$1,949,000

Response:

Forecasted retirements for asset class 402-01 and 402-02 are based on the approved amortization accounting approach where assets are retired at their end of their estimated life, with no gains/losses recorded. The forecasted amounts noted above represent assets forecast to be fully depreciated and no longer in use.

86.3.7 Schedule 47 – please provide calculation/support for forecasted 2012 retirements related to:

465-00 Mains	$1,065,000
473-00 Services	$2,947,000
474-00 House Regulators & Meter Installations	$1,783,000
475-00 Mains	$2,834,000
478-10 Meters	$3,915,000

Response:

Forecast retirements for 465-00 Mains were calculated based on a five year historical average of actual retirements in this asset class compared to its additions. In 2012, approximately $1.0 million in retirements was forecasted based on 4.8 percent of $22 million in additions.

Retirements for 473-00 Services were forecasted based on the anticipated length of services to be retired multiplied by an average unit cost per service. In 2012, approximately $2.9 million in service retirements was forecasted from 5,820 service retirements at approximately $500 per service retirement.

With the recommended revised amortization accounting approach to this asset as discussed in the Asset Loss report, no retirements were forecasted for 474-00 House Regulators & Meter Installations except for those existing assets that were expected to reach zero net book value in the year.

Forecast retirements for 475-00 Mains were calculated based on a five-year historical average of actual retirements in this asset class compared to its additions. In 2012, approximately $2.8 million in retirements was forecasted based on 12.3 percent of $23 million in additions.

Retirements for 478-10 Meters in 2012 were calculated based on 37,875 residential and 390 industrial anticipated meter retirements multiplied by the 2010 average actual retirement cost of $100 per meter.

86.3.8 Schedule 48 – please provide calculation/support for forecasted 2012 retirements related to:

483-10 GP Computer Hardware	$1,517,000
484-00 Vehicles Leased	$1,908,000

Response:

Forecasted retirements for asset class 483-10 are based on the approved amortization accounting approach where assets are retired at the end of their estimated life, with no gains/losses recorded. The forecasted amounts noted above represent assets forecast to be fully amortized in 2012.

Forecast retirements for asset class 484-00 Vehicles – Leased were calculated as a percentage of anticipated vehicle additions. In 2012, approximately $1.9 million in retirements was projected based on 60 percent of estimated additions of $3.2 million.

86.3.9 Schedule 49 – please provide calculation/support for forecasted 2013 retirements related to:

402-01 Application Software – 12.5%	$6,015,000
402-02 Application Software – 20%	$2,997,000

Response:

Forecasted retirements for asset class 402-01 and 402-02 are based on the approved amortization accounting approach where assets are retired at the end of their estimated life, with no gains/losses recorded. The forecasted amounts noted above represent assets forecast to be fully amortized in 2012.

86.3.10 Schedule 50 – please provide calculation/support for forecasted 2013 retirements related to:

473-00 Services	$2,806,000
475-00 Mains	$3,404,000
478-10 Meters	$3,915,000

Response:

Retirements for 473-00 Services were forecasted based on the anticipated length of services to be retired multiplied by an average unit cost per service. In 2013, approximately $2.8 million in service retirements was forecasted from 5,500 service retirements at approximately $500 per service retirement.

Forecast retirements for 475-00 Mains were calculated based on a five year historical average of actual retirements in this asset class compared to its additions. In 2013, approximately $3.4 million in retirements was forecasted based on 12.3 percent of $28 million in additions.

Forecast retirements for asset class 478-10 Meters in 2013 were calculated based on 37,875 residential and 390 industrial anticipated meter retirements multiplied by the 2010 average actual retirement cost of $100 per meter.

86.3.11 Schedule 51 – please provide calculation/support for forecasted 2013 retirements related to:

483-40 GP Furniture	$1,954,000
483-10 GP Computer Hardware	$6,489,000
484-00 Vehicles – Leased	$1,716,000

Response:

Forecast retirements for asset class 483-10 and 483-40 are based on the approved amortization accounting approach where assets are retired at the end of their estimated life, with no gains/losses recorded. The forecasted amounts noted above represent assets forecast to be fully amortized in 2013.

Forecast retirements for asset class 484-00 Vehicles – Leased were calculated as a percentage of anticipated vehicle additions. In 2013, approximately $1.7 million in retirements was projected based on 60 percent of estimated additions of $2.9 million.

86.4 Please provide support for the determination of forecasted retirements for FEI-Fort Nelson in Section 7, Tab 7.4, Schedules 43-51, as follows:

86.4.1 Schedule 45 – please provide calculation/support for projected 2011 retirements related to:

482-00 Structures & Improvements Masonry Buildings $146,000

Response:

Retirements for asset class 482-00 Structures & Improvements in 2011 were based on the retirement of two buildings (a muster shop and a storage building) that have been replaced, are fully depreciated and will no longer be in use after 2011. A 2,600 sq ft. building was constructed in 2010 as a replacement in a different location on the same site in order to maintain a safe and healthy workplace.

86.5 Please provide details for forecast plant additions for FEI-Mainland in Section 7, Tab 7.1, Schedules 43-51, as follow (details should include a listing of additions breaking down each individual additions greater than $500,000. All other can be grouped together as an "other category." For any forecast additions greater than $1,000,000, a brief project description should be provided and a description of project overruns, if any, should be noted. For any forecast additions greater than $5,000,000, a description of the project, reference to the application approving the project, the forecast budget included in the application and the actual costs for the project (total) should be provided) These descriptions should note if the asset is a new item or a replacement items. For replacement items, please note what assets are being replaced by the project noting their remaining service life and unamortized carrying value. For new items the description should also note how the asset correlates to capacity increases or main extensions:

86.5.1 Schedule 43 – please provide details/support for projected 2011 additions as follows:

402-01 Application Software – 12.5%	$4,800,000
402-02 Application Software – 20%	$4,800,000
449-00 Local Storage Equipment (Tilbury)	$2,137,000

Response:

Provided below are the details for the projected 2011 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
Mobile GIS	new	N/A		1,302			
Integrated Work Management System	Replacement	N/A		1,103			
Microsoft License	Replacement	N/A		1,492			
402-01 Application Software - 12.5%			**-**	**3,897**	**-**	**903**	**4,800**
Employee & Manager Self Serve	new	N/A	689				
Project Portfolio Management Tool	new	N/A	648				
BC One Call	Replacement	N/A	468				
Risk Analysis	new	N/A	581				
Worksoft Certify Performance Test	Replacement	N/A	329				
402-02 Application Software - 20%			**2,714**	**-**	**-**	**2,087**	**4,800**
449-00 Local Storage Equipment (Tilbury)						**2,137**	**2,137**

For any projected additions noted above that are greater than $1,000,000, a project description is provided below:

1) **Mobile GIS** – This project is for the implementation of a Mobile GIS to be used by Transmission, Distribution, and Systems Integrity group in the field.

   Currently, FEI's Geospatial Information System (GIS) platform is Smallworld. The application used in Distribution to display the GIS data is AMFM. Primarily used in the office, the AMFM system provides valuable information regarding FEI's assets as well as the work history and DCRS (Digitized Construction Records System) information. The ability to communicate and transfer this information to field employees is a necessity.

   In today's workplace, employees at large expect to work with accurate information that is as close as possible to real-time. FEI needs to move away from using dated information in the field. A fully functional, mobile GIS solution would formalize data updates and the dissemination of formal GIS information in the file.

2) **Integrated Work Management System** - The Integrated Work Management System (IWMS) project will equip the Facilities Group with an integrated tool set to proactively track, manage data and support planning within the lease, space and maintenance areas. FEI's current application is limited in its capability and does not provide Facilities with an integrated view into all data processed by the group.

3) **Microsoft License** – The Microsoft License project involves payments for the annual true up of the Microsoft Enterprise Agreement, which includes licensing for Operating System (OS), Office applications and business-critical software that supports core activities and processes within the FEU.

Note: FEI Mainland is not aware of any overruns for these three identified projects at this time.

The FEU note that it follows the approved amortization accounting approach for software (i.e. assets retired when fully amortized at either 5 or 8 years). As a result, the remaining service lives and unamortized carrying values of the software assets being replaced are not applicable, and no gains/losses will ever be recognized.

86.5.2 Schedule 44 – please provide details/support for projected 2011 additions as follows:

465-00 Mains	$7,726,000
466-00 Compressor Equipment	$1,300,000
473-00 Services	$15,448,000
474-00 House Regulators & Meter Installations	$10,647,000
475-00 Mains	$16,788,000
477-00 Measuring & Regulating Equipment	$3,700,000
478-10 Meters	$10,647,000

Response:

Provided below are the details for the projected 2011 additions. Note that for the asset category 465-00 the $7,726,000 above only includes regular capital additions; FEI has also included CPCNs (projects greater than $5 million) in the table below to provide a complete response.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
CPCN: Fraser River Crossing					36,281		
CPCN: Kootenay River Crossing					6,870		
SN17/ILI launchers(2) replacement	Replacement	N/A	520				
465-00 Mains			**520**	**-**	**43,151**	**7,206**	**50,877**
466-00 Compressor Equipment						**1,300**	**1,300**
473-00 Services						**15,448**	**15,448**
474-00 House Regulators & Meter Installations						**10,647**	**10,647**
219DP Columbia River, Trail	Replacement	N/A	800				
London Street, New West	Replacement	N/A	662				
152 St, Surrey	Replacement	N/A		1,005			
Westside Rd, West Kelowna	Replacement	N/A	790				
475-00 Mains			**2,252**	**1,005**	**-**	**13,531**	**16,788**
Trenton Gate Station, Coquitlam	Replacement	N/A	900				
Chilliwack Gate Station	Replacement	N/A	880				
477-00 Measuring & Regulating Equipment			**1,780**	**-**	**-**	**1,920**	**3,700**
478-10 Meters						**10,647**	**10,647**

For any projected additions noted above that are greater than $1,000,000, a project description is provided below:

1) **152 St, Surrey** – The 152 St Surrey Project consists of replacing approximately 780m of 323mm IP Pipeline that is located in 152 Street at Colebrook Road, Surrey. It involves the installation of new pipe and abandonment of existing ones in conjunction with City of Surrey construction of an overpass at Colebrook Road. The costs for the work are anticipated to be recoverable from the City of Surrey.

Note: At this time, FEI Mainland anticipates the project to be on budget.

With the group asset accounting approach (i.e. assets are not tracked individually) used for most of its assets, the FEU are unable to specifically identify for the items noted as replacement their specific remaining service life and unamortized carrying value. As discussed in the response to BCUC IR 1.86.1, the FEU forecast the majority of its retirements not by specific assets but instead only by asset class based on a historical average approach (i.e. retirements as a percentage of additions). Consequently, the FEU do not forecast any gains/losses on retirements by specific assets.

For any projected additions greater than $5,000,000, please refer to Section 6.2.7.1, pages 381 and 382 of the Application (Exhibit B-1) for project description, reference to the application approving the project, and the projection included in the application. For details on total actual costs for the project, please refer to the latest Quarterly Progress Reports.

86.5.3 Schedule 45 - please provide details/support for projected 2011 additions as follows:

476-10 NG Transportation CNG Dispensing Equipment	$1,386,000
476-20 NG Transportation LNG Dispensing Equipment	$1,180,000
482-00 Structures & Improvements - Masonry Buildings	$2,555,000
483-10 GP Computer Hardware	$6,400,000
484-00 Vehicles – Leased	$3,710,000
486-00 Small Tools & Equipment	$3,265,000

Response:

Provided below are the details for the projected 2011 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
476-10 NG Transportation CNG Dispensing Equipment						**1,386**	**1,386**
476-20 NG Transportation LNG Dispensing Equipment						**1,180**	**1,180**
						-	
Surrey Shed Replacement	Replacement	N/A	900				
482-00 Structures & Improvements - Masonry Buildings			**900**	**-**	**-**	**1,655**	**2,555**
						-	
Disaster Recovery Project	new	N/A		947			
AVL Implementation	new	N/A	891				
2011 SAN Refresh	Replacement	N/A	576				
2011 Network Infrastructure	Replacement	N/A		1,258			
Infrastructure Storage - Part 2	Replacement	N/A	450				
483-10 GP Computer Hardware			**1,917**	**2,205**	**-**	**2,278**	**6,400**
						-	
484-00 Vehicles - Leased						**3,710**	**3,710**
486-00 Small Tools & Equipment						**3,265**	**3,265**

For any projected additions noted above that are greater than $1,000,000, a project description is provided below:

1) **Disaster Recovery** – The Disaster Recovery project will provide an alternate location to run critical business systems in the event of disaster impacting our server room at Surrey Operations.

2) **2011 Network Infrastructure** – The Network Refresh Program is an ongoing initiative to proactively replace FEI's aging IT network and security infrastructure with new technology based on business needs, technology standards and optimal refresh cycle. The 2011 Project replaces network switches in Surrey Operations, wireless endpoint access devices, and implements Public Key Infrastructure to enable digital certificate management capability.

Note: At this time, FEI Mainland anticipates these projects to be on budget.

The FEU also note that they follow the approved Amortization accounting approach for Hardware / Software. As a result, for the Hardware assets being replaced, remaining service lives and unamortized carrying values are non-applicable as no gains/losses are recognized. For the Surrey Operations shed being replaced, there is no remaining book value for the existing asset.

86.5.4 Schedule 46 - please provide details/support for forecasted 2012 additions as follows:

402-01 Application Software – 12.5%	$5,400,000
402-02 Application Software – 20%	$5,400,000
449-00 Local Storage Equipment (Tilbury)	$2,050,000

Response:

Provided below are the details for the forecast 2012 additions.

Project name	New or Replacement Asset	note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
Mobile GIS	New	N/A		97			
402-01 Application Software - 12.5%			**-**	**97**	**-**	**5,303**	**5,400**
402-02 Application Software - 20%						**5,400**	**5,400**
2nd Boiloff - Tilbury LNG	New	Ensures Reliability of Facility	1,000				
Tilbury Electrical System Upgrade	Upgrade	N/A	750				
449-00 Local Storage Equipment (Tilbury)			**1,750**	**-**	**-**	**300**	**2,050**

For a description of the Mobile GIS Project, please refer to BCUC IR 1.86.5.1.

86.5.5 Schedule 47 - please provide details/support for forecasted 2012 additions as follows:

465-00 Mains	$22,196,000
465-00 Mains – INSPECTION	$1,531,000
466-00 Compressor Equipment	$4,021,000
473-00 Services	$16,950,000
477-00 Meters/Regulators Installations	$11,074,000
475-00 Mains	$23,037,000
477-00 Measuring & Regulating Equipment	$2,930,000
478-10 Meters	$11,316,000

Response:

Provided below are the details for the forecast 2012 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
465-00 Mains			-	-	-	**22,196**	**22,196**
465-00 Mains - INSPECTION						**1,531**	**1,531**
Unit Repowering Kingsvale	New	Capacity Increases	850				
466-00 Compressor Equipment			**850**	-	-	**3,171**	**4,021**
473-00 Services						**16,950**	**16,950**
477-00 Meters/Regulators Installations						**11,074**	**11,074**
Lougheed Hwy, Burnaby	Replacement	N/A	375				
Lougheed & Railway, Mission	Replacement	N/A	900				
475-00 Mains			**1,275**	-	-	**21,762**	**23,037**
New Station, West Kelowna	New	Additional supply to local area	500				
Canfor Pulp Line Heater, PG	Replacement	N/A	600				
477-00 Measuring & Regulating Equipment			**1100**	**0**	**0**	**1,830**	**2,930**
478-10 Meters						**11,316**	**11,316**

For a description of the Lougheed Highway, Burnaby Project, please refer to BCUC IR 1.86.5.8.

With the group asset accounting approach (i.e. assets are not tracked individually) used for most of its assets, the FEU are unable to specifically identify for the items noted as replacement their specific remaining service life and unamortized carrying value. As discussed in the response to BCUC IR 1.86.1, the FEU forecast the majority of retirements not by specific assets but instead only by asset class based on a historical average approach (i.e. retirements as a percentage of additions). Consequently, the FEU do not forecast any gains/losses on retirements by specific assets.

86.5.6 Schedule 48 - please provide details/support for forecasted 2012 additions as follows:

476-10 NG Transportation CNG Dispensing Equipment	$1,540,000
476-20 NG Transportation LNG Dispensing Equipment	$1,180,000
480-00 Land in Fee Simple	$2,000,000
482-00 Structures & Improvements -Masonry Buildings	$3,777,000
483-40 GP Furniture	$1,536,000
483-10 GP Computer Hardware	$7,200,000

484-00 Vehicles – Leased $3,180,000
486-00 Small Tools & Equipment $3,009,000

Response:

Provided below are the details for the forecast 2012 additions.

Project name	New or Replacement Asset	note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
476-10 NG Transportation CNG Dispensing Equipment						**1,540**	**1,540**
476-20 NG Transportation LNG Dispensing Equipment						**1,180**	**1,180**
North Vancouver Muster - Land Purchase	New	N/A		2,000			
480-00 Land in Fee Simple			**0**	**2,000**	**0**	**-**	**2,000**
						-	
Surrey Office Densification - Infrastructure	New	N/A	500				
North Vancouver Muster - Building Modificaton or Build	New	N/A	500				
Langley Compressor	New	N/A	635				
Penticton Meter Shop Modification	Addition to Asset	N/A	750				
482-00 Structures & Improvements - Masonry Buildings			**2,385**	**-**	**-**	**1,392**	**3,777**
						-	
Surrey Office Densification - Furniture	New	N/A		1,500			
483-40 GP Furniture			-	1,500	-	**36**	**1,536**
Disaster Recovery Project	New	N/A		81			
483-10 GP Computer Hardware			**-**	**81**	**-**	**7,119**	**7,200**
484-00 Vehicles - Leased						**3,180**	**3,180**
486-00 Small Tools & Equipment						**3,009**	**3,009**

For any forecast additions noted above that are greater than $1,000,000, a project description is provided below. These descriptions have also been included in the Application on Page 372.

1) **North Shore Muster Land Purchase** – In 2012, Facilities also proposes to purchase land for the North Vancouver Muster for an estimated $2 million. This estimate is based on the requirement of approximately 0.5 acre at the current market rate of $85 square foot. The muster is currently leased and, due to an expansion for the Landlord, we will be forced out and not able to operate from this site. This site is critical for the Operations department as it provides operational support for the North and West Vancouver areas and is on the north side of the Burrard Inlet to ensure resources are always available for this area in the event of an emergency. The Landlord has provided reasonable timelines for their expansion and Facilities has been exploring alternatives for two years with no success due to the limited industrial real estate market.

2) **Surrey Office Densification (Furniture)** – The increased pressure to the Surrey site parking and office space will continue in 2012 as forecast employees and project consultants at this location continue to rise. Facilities is planning on increasing the densification of the Surrey Operations site and increasing the workstation count. This densification will require the purchase of new additional furniture systems to build out new workstations and alter existing workstations. The furniture costs are estimated at $1.5 million. Densification will eliminate the requirement for additional O&M of over $1.7 million per year for a leased facility and will maintain the business groups at one facility to support efficiency and collaboration within the groups.

For a description of the Disaster Recovery Project, please refer to BCOAPO IR 1.86.5.3.

Note: At this time, FEI Mainland anticipates these projects to be on budget.

86.5.7 Schedule 49 - please provide details/support for forecasted 2013 additions as follows:

402-01 Application Software – 12.5% $5,400,000

402-02 Application Software – 20% $5,400,000

Response:

Provided below are the details for the forecast 2013 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
402-01 Application Software - 12.5%						**5,400**	**5,400**
402-02 Application Software - 20%						**5,400**	**5,400**

Please refer to the Application (Exhibit B-1), Section 6, Rate Base pages 376 to 378 and BCUC IR 1.97.1 for a discussion of how IT capital expenditures are forecasted.

86.5.8 Schedule 50 - please provide details/support for forecasted 2013 additions as follows:

465-00 Mains	$18,722,000
465-00 Mains – INSPECTION	$1,342,000
466-00 Compressor Equipment	$3,369,000
473-00 Services	$18,700,000
477-00 Meters/Regulators Installations	$11,500,000
478-00 Mains	$27,675,000
477-00 Measuring & Regulating Equipment	$2,980,000
478-10 Meters	$11,689,000

Response:

Provided below are the details for the forecast 2013 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
465-00 Mains						**18,722**	**18,722**
465-00 Mains - INSPECTION						**1,342**	**1,342**
Combustor Upgrade Kit B	Replacement	N/A	500				
466-00 Compressor Equipment			**500**	-	-	**2,869**	**3,369**
473-00 Services						**18,700**	**18,700**
477-00 Meters/Regulators Installations						**11,500**	**11,500**
Lougheed Hwy, Burnaby	Replacement	N/A		1,500			
475-00 Mains			-	**1,500**	-	**26,175**	**27,675**
Vernon Station	Replacement	N/A	900				
477-00 Measuring & Regulating Equipment			**900**	-	-	**2,080**	**2,980**
Canfor, Mackenzie	New	Customer supply separation	600				
478-10 Meters			**600**	-	-	**11,089**	**11,689**

For any forecast additions noted above that are greater than $1,000,000, a project description is provided below. This discussion is also found on Page 351 of the Application (Exhibit B-1).

1) **Lougheed Highway, Burnaby** – The Lougheed Highway Main Replacement project consists of replacing approximately 4.5km of existing 168mm steel main with polyethylene pipe along the existing route or along another, as the existing steel main has had periods of significant leaks and unusual failures.

As it is very likely there will be future leaks or pipe failures, the installation of new pipe will reduce the probability of a significant interruption to the operation of Skytrain and interference with the primary highway thoroughfare. Other sections have been replaced in the past.

It will be necessary to undertake design and community relations activities in 2012 with construction to occur in the following two years. The proposed expenditure is $375 thousand and $1.5 million in 2012 and 2013 respectively with project completion in 2014.

With the group asset accounting approach (i.e. assets are not tracked individually) used for most of its assets, the FEU are unable to specifically identify for the items noted as replacement their specific remaining service life and unamortized carrying value. As discussed in the response to BCUC IR 1.86.1, the FEU forecast the majority of retirements not by specific assets but instead only by asset class based on a historical average approach (i.e. retirements as a percentage of additions). Consequently, the FEU do not forecast any gains/losses on retirements by specific assets.

86.5.9 Schedule 51 - please provide details/support for forecasted 2013 additions as follows:

476-10 NG Transportation CNG Dispensing Equipment	$1,386,000
476-20 NG Transportation LNG Dispensing Equipment	$1,180,000
482-00 Structures & Improvements - Masonry Buildings	$2,650,000
483-10 GP Computer Hardware	$7,200,000
484-00 Vehicles – Leased	$2,860,000
486-00 Small Tools & Equipment	$3,024,000

Response:

Provided below are the details for the forecast 2013 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
476-10 NG Transportation CNG Dispensing Equipment						**1,386**	**1,386**
476-20 NG Transportation LNG Dispensing Equipment						**1,180**	**1,180**
Williams Lake Muster	Replacement	N/A	600				
482-00 Structures & Improvements - Masonry Buildings			**600**	**-**	**-**	**2,050**	**2,650**
						-	
483-10 GP Computer Hardware						**7,200**	**7,200**
484-00 Vehicles - Leased						**2,860**	**2,860**
486-00 Small Tools & Equipment						**3,024**	**3,024**

86.6 Please provide details/support for plant additions for FEI-Fort Nelson in Section 7, Tab 7.4, Schedules 43-51, as follows:

86.6.1 Schedule 44 – please provide details/support for projected 2011 additions as follows:

465-00 Mains $2,876,000

Response:

Provided below are the details for the projected 2011 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
Muskwa River Crossing	Replacement	N/A		2,866			
465-00 Mains			**-**	**2,866**	**-**	**10**	**2,876**

For any forecast additions noted above that are greater than $1,000,000, a project description is provided below:

1) **Muskwa River Crossing** – Natural Gas service to the Fort Nelson area is provided by a single 114mm transmission pressure pipeline that crosses the Muskwa River on the southeast side of the town. This pipeline has become exposed and is now at risk of damage from river action. Expenditures are required to replace the pipeline crossing. As approved by the Commission in Order No. G-27-11, a river crossing replacement using the adjacent highway bridge is projected to be the most cost-

effective strategy. Total project costs for this option are currently estimated at $3.0 million (excluding AFUDC), unchanged from the approved amount. Of this total, approximately $2.9 million will be added to rate base in late 2011, with the remainder being added in 2012. The retirement of this asset is included in Tab 7.4, Schedule 44 in the Application (Exhibit B-1).

Please also see the response to BCUC IR 1.17.1 for a discussion of the Muskwa River Crossing Project.

86.6.2 Schedule 47 - please provide details/support for forecasted 2012 additions as follows:

465-00 Mains $290,000

Response:

Provided below are the details for the forecast 2012 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
Muskwa River Crossing	Replacement	N/A		150			
465-00 Mains			**-**	**150**	**-**	**140**	**290**

Please refer to BCUC IR 1.86.6.1 for explanation. The $150 thousand is part of the Muskwa River project discussed in that response.

86.6.3 Schedule 48 - please provide details/support for forecasted 2012 additions as follows:

482-00 Structures & Improvements -Masonry Buildings $129,000

Response:

Provided below are the details for the forecast 2012 additions. This project is discussed on Pages 374 and 375 of the Application (Exhibit B-1).

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
482-00 Structures & Improvements - Leasehold Improvement						**129**	**129**

86.6.4 Schedule 50 - please provide details/support for forecasted 2013 additions as follows:

475-00 Mains $147,000

Response:

Provided below are the details for the projected 2013 additions.

Project name	New or Replacement Asset	If "New" Asset, note how the asset correlates to "capacity increases" or "main extensions"	$500K - $1M	$1M -$5M	>$5M	Other	TOTAL
475-00 Mains						**147**	**147**

86.7 Total additions for income tax purposes on Schedules 36-38 of Section 7, Tabs 7.1 to 7.4 do not agree with the total additions shown in schedules 43-51. Please provide a reconciliation of the total additions between these schedules for each respective utility. The reconciliation could be done in the following format:

	FEI Mainland	FEVI	FEW	FEI Fort Nelson
Total additions per Schedules 43-51				
Add/deduct: *Please describe reconciling item*				
Add/deduct: *Please describe reconciling item*				
Total additions per Schedules 36-38				

Response:

The following tables, by year, reconcile accounting plant additions, including CPCN's, to the total net additions for income tax for each of the four utilities.

2011	**Reference**	FEI - Mainland	FEVI	FEW	FEI - Fort Nelson
CPCN's	Sched. 45	$ 43,363	$ 212,964	$ -	$ -
Additions	Sched. 45	102,889	23,464	447	3,099
AFUDC	Sched. 45	1,256	150	-	152
Capitalized Overhead	Sched. 45	30,054	4,567	121	114
Total Plant Additions per Schedule 45		177,562	241,145	568	3,365
Less: Land / Land Rights	Scheds. 43, 44 & 45	(465)	(1,891)	-	-
Less: Leased Vehicles	Sched. 45	(3,710)	-		
Less: AFUDC	Sched. 45	(1,256)	(150)	-	(152)
Less: AFUDC incl. in CPCN's added to to UCC		(2,841)	(19,706)	-	-
Less: CIAC Additions	Sched. 63	(10,718)	(488)	-	-
Less: Overheads Capitalized Expensed for Tax	Sched. 33	(12,881)	(2,936)	(78)	(49)
Less: Mt Hayes CPCN - Additions and Adjustments to 2010 UCC			(81,593)		
Add: Other Tax Adjustments - Mt Hayes			1,807		
Less: Inspection Costs	Sched. 44	(626)	(550)		
Add: Transfers/Recovery	Sched. 45	3,692			
Rounding		4	1	-	-
Total CCA Additions per Schedule 36		$148,761	$ 135,639	$ 490	$ 3,164

2012	**Reference**	FEI - Mainland	FEVI	FEW	FEI - Fort Nelson
CPCN's	Sched. 48	$ 82,393	$ 21,973	$ 221	$ -
Additions	Sched. 48	137,150	29,950	719	609
AFUDC	Sched. 48	1,948	139	-	-
Capitalized Overhead	Sched. 48	31,375	4,933	127	120
Total Plant Additions per Schedule 48		252,866	56,995	1,067	729
Less: Land / Land Rights	Scheds. 46, 47 & 48	(16,487)	(6,435)	-	-
Less: Leased Vehicles	Sched. 48	(3,180)	-		
Less: AFUDC	Sched. 48	(1,948)	(139)	-	-
Less: AFUDC incl. in CPCN's added to to UCC		(2,469)	(666)	(7)	-
Less: CIAC Additions	Sched. 64	(16,841)	(426)	-	-
Less: Overheads Capitalized Expensed for Tax	Sched. 34	(13,447)	(3,171)	(82)	(52)
Less: Inspection Costs	Sched. 47	(1,531)	(275)		
Add: CIAC Adjustments	Sched. 64		2,484		
Rounding		4	1	(2)	2
Total CCA Additions per Schedule 37		$196,967	$ 48,368	$ 976	$ 679

2013	**Reference**	FEI - Mainland	FEVI	FEW	FEI - Fort Nelson
CPCN's	Sched. 51	$ -	$ -	$ -	$ -
Additions	Sched. 51	133,671	29,079	480	276
AFUDC	Sched. 51	1,769	147	-	-
Capitalized Overhead	Sched. 51	33,106	4,967	128	125
Total Plant Additions per Schedule 51		168,546	34,193	608	401
Less: Land / Land Rights	Scheds. 49, 50 & 51	(778)	(82)	-	-
Less: Leased Vehicles	Sched. 51	(2,860)	-		
Less: AFUDC	Sched. 51	(1,769)	(147)	-	-
Less: CIAC Additions	Sched. 65	(6,900)	(431)	-	-
Less: Overheads Capitalized Expensed for Tax	Sched. 35	(14,188)	(3,193)	(82)	(54)
Less: Inspection Costs	Sched. 50	(1,342)			
Rounding		1	-	1	1
Total CCA Additions per Schedule 38		$140,710	$ 30,340	$ 527	$ 348

87.0 Reference: Allowance for Funds Used During Construction (AFUDC)

Exhibit B-1, Application, Section 6.1.5.1, pp.323-324

Computation of the AFUDC Rates and Amounts

Figure 6.1-2: After Tax Weighted Average Cost of Capital Formula

(ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1- Tax Rate)

Table 6.1-11: Forecast AFUDC Rates for 2012 and 2013

Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	6.83%	6.77%	6.76%
Vancouver Island	6.63%	6.44%	6.56%
Whistler	6.26%	6.17%	6.27%

87.1 Please provide supporting calculations for the above AFUDC rates as well as the After Tax Weighted Average Cost of Capital used in determining the AFUDC rates.

<u>Response:</u>

Provided below are the calculations for the AFUDC rates referenced in Table 6.1-11 of the Application (Exhibit B-1). Please note that the after tax weighted average cost of capital is equivalent to the AFUDC rate for each utility.

Please refer to Schedules 80 and 81 of Sections 7.1 to 7.3 of the Application (Exhibit B-1), for the forecast return on capital for 2012 and 2013 and Schedules 30 to 32 of Sections 7.1 to 7.3 for approved and forecast tax rates.

Mainland	Approved 2011	Forecast 2012	Forecast 2013
ROE	9.50%	9.50%	9.50%
Equity	40.00%	40.00%	40.00%
STD rate	4.50%	2.75%	3.75%
STD %	1.63%	2.18%	3.24%
LTD rate	6.95%	6.73%	6.74%
LTD %	58.37%	57.82%	56.76%
Tax	26.50%	25.00%	25.00%
AFUDC Rate/ After Tax WACC	6.83%	6.76%	6.76%

AFUDC Rate = (ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1-Tax Rate)

Vancouver Island	Approved 2011	Forecast 2012	Forecast 2013
ROE	10.00%	10.00%	10.00%
Equity	40.00%	40.00%	40.00%
STD rate	4.75%	4.25%	5.25%
STD %	6.40%	13.61%	17.01%
LTD rate	6.12%	5.75%	5.85%
LTD %	53.60%	46.39%	42.99%
Tax	26.50%	25.00%	25.00%
AFUDC Rate/ After Tax WACC	6.63%	6.43%	6.56%

AFUDC Rate = (ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1-Tax Rate)

Whistler	Approved 2011	Forecast 2012	Forecast 2013
ROE	10.00%	10.00%	10.00%
Equity	40.00%	40.00%	40.00%
STD rate	5.15%	3.75%	4.75%
STD %	13.05%	12.54%	11.81%
LTD rate	5.11%	5.11%	5.11%
LTD %	46.95%	47.46%	48.19%
Tax	26.50%	25.00%	25.00%
AFUDC Rate/ After Tax WACC	6.26%	6.17%	6.27%

AFUDC Rate = (ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1-Tax Rate)

87.2 Please provide AFUDC rates for 2009 and 2010 and projected 2011 AFUDC rates by completing the following table:

Utility/Region	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland			6.83%		6.77%	6.76%
Vancouver Island			6.63%		6.44%	6.56%
Whistler			6.26%		6.17%	6.27%
Fort Nelson						

Response:

The AFUDC rates are set once each year and are based on the Commission approved capital structure, ROE, and interest and tax rates. The AFUDC rates are not adjusted throughout the year; therefore, projected AFUDC rates are not applicable, and actual rates equal approved. The table has been updated to reflect the approved AFUDC rates for each year.

Utility/Region	Approved 2009	Approved 2010	Approved 2011	Forecast 2012	Forecast 2013
Mainland	6.02%	6.73%	6.83%	6.77%	6.76%
Vancouver Island	6.09%	6.36%	6.63%	6.44%	6.56%
Whistler	5.98%	5.99%	6.26%	6.17%	6.27%
Fort Nelson	6.02%	6.73%	6.83%	6.77%	6.76%

87.2.1 For the AFUDC rates above, please provide explanations for variances from the prior year greater than +/- 5%.

Response:

Variances for year over year AFUDC rates reflect changes in the capital structure as approved by the Commission. The following table provides the year over year change in AFUDC rates as provided in the response to BCUC IR 1.87.2, expressed as a percent.

Year Over Year Change in AFUDC Rate, as a %					
Utility/Region	**Approved 2009**	**Approved 2010**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland		11.79%	1.49%	-0.88%	-0.15%
Vancouver Island		4.43%	4.25%	-2.87%	1.86%
Whistler		0.17%	4.51%	-1.44%	1.62%
Fort Nelson		11.79%	1.49%	-0.88%	-0.15%

The only variance greater than 5 percent is the change in FEI's AFUDC rate between 2009 and 2010. The variance between 2010 and 2009 in FEI is attributable to the change in Return on Equity ("ROE") and the increase from 35.01 percent equity in 2009 to 40 percent equity in 2010, as approved by Commission Order No. G-158-09.

87.3 Why are there no rates forecasted for Fort Nelson, when AFUDC amounts have been included in rate base for Fort Nelson (e.g. Section 7, Tab 7.4, Schedule 44, $152,000 in AFUDC has been added to Mains for 2011 but no amounts have been shown in Table 6.1-12 nor any AFUDC rates in Table 6.1-11.)

Response:

The Mainland AFUDC rate is applied to capital spending and non-rate base deferral accounts in Fort Nelson; therefore a separate AFUDC rate for Fort Nelson does not exist. Table 6.1-11 may be updated to reflect an AFUDC rate for Fort Nelson equivalent to the Mainland AFUDC rate as follows:

REVISED Table 6.1-11: Forecast AFUDC Rates for 2012 and 2013

Utility/Region	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	6.83%	6.76%	6.76%
Vancouver Island	6.63%	6.43%	6.56%
Whistler	6.26%	6.17%	6.27%
Fort Nelson	6.83%	6.76%	6.76%

Although separate and distinct entities for regulatory and ratemaking purposes, Fort Nelson is a division of FEI for legal purposes and as such debt financing rates reflect those of FEI. That is, the short-term debt rates applicable to Fort Nelson are the short-term debt rates in FEI and the long-term debt in Fort Nelson reflects an allocation of long-term debt from FEI (Application, Exhibit B-1, Section 5.7.1.2, page 309). Furthermore, the approved return on equity and the equity component of rate base in Fort Nelson are equivalent to the approved rates in FEI. Reflecting this financing approach, the Mainland AFUDC rate is applicable to Fort Nelson.

Approved and Forecast AFUDC

Table 6.1-12: Approved and Forecast AFUDC

($ thousands) **Utility/Region**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 5,051	$ -	$ -
Vancouver Island	3,703	604	-
Whistler	-	-	-
Fort Nelson	-	-	-
	$ 8,754	**$ 604**	**$ -**

87.4 The amounts of the approved and forecasted AFUDC above in Table 6.1-12 do not agree with total AFUDC amounts shown in Schedules 43-51 of Section 7, Tabs 7.1 to 7.4 for each utility. Please explain why they do not agree and if they should.

<u>Response:</u>

The AFUDC amounts provided in Table 6.1-12 and the AFUDC amounts provided in Schedules 43-51 of Section 7 of the Application (Exhibit B-1) will not agree as they represent different components of AFUDC:

- The revised Table 6.1-12 (see BCUC IR 1.87.5) has the amount of AFUDC for CPCN's, regular plant capital expenditures and for the Customer Care Enhancement costs that is charged to the deferral account in each year. The total AFUDC incurred related to a CPCN addition is included in Column 3 of Schedules 43-51 in Section 7.

- Schedules 43-51 of Section 7 (Column 5) reflect the amounts of AFUDC specific to regular capital expenditures that are included in plant additions each year. Please refer to Schedule 42, Line 28 for the total AFUDC applied to regular capital in each year.
- The AFUDC related to the Customer Care Enhancement is charged to the non-Rate Base Deferral account in 2011. In 2012 the deferral is transferred to Rate Base and no AFUDC is then charged to the deferral account in 2012.

87.5 Please provide AFUDC amounts for 2009 and 2010 and projected 2011 by completing the following table:

Utility/Region ($000's)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland			5,051		-	-
Vancouver Island			3,703		604	-
Whistler			-		-	-
Fort Nelson			-		-	-
Total			8,754		604	-

Response:

Table 6.1-12 as provided in the Application (Exhibit B-1), was incorrect. Provided below is a revised Table 6.1-12 with a summary of AFUDC amounts for 2009 and 2010 and projected 2011 and forecast 2012 and 2013. A higher projection of AFUDC in 2011 as compared to approved is attributed to the Mt. Hayes LNG Storage Facility going into service two months later than initially anticipated. Please note that this table also includes the AFUDC for the Customer Care deferral account as well as for CPCNs and regular plant.

Utility/Region ($000's)	Actual 2009	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland	1,394	3,459	5,878	5,244	1,872	1,769
Vancouver Island	5,553	9,361	3,650	5,951	742	147
Whistler	181	2	-	7	-	-
Fort Nelson	-	-	-	152	-	-
Total	7,128	12,822	9,528	11,354	2,614	1,916

87.5.1 For the AFUDC amounts above, please provide explanations for variances from the prior year that are greater than +/- 5%.

Response:

Please refer to BCUC IR 1.87.5. Below is an updated Table 6.1-12.

Utility/Region ($000's)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	5,878	1,872	1,769
Vancouver Island	3,650	742	147
Whistler	-	-	-
Fort Nelson	-	-	-
Total	9,528	2,614	1,916

AFUDC in 2012 is forecast to be lower than approved 2011 mainly due to the Mt. Hayes LNG Storage Facility, Fraser River Crossing, and Kootenay River Crossing going into service in 2011. A lower forecast of AFUDC in 2013 is mainly due to the Victoria Regional Office going into service in 2012.

88.0 Reference: Contributions in Aid of Construction (CIAC)

Exhibit B-1, Application, Section 6.1.5.2, pp.324-325; Section 6.2, pp. 331-335;

Section 7, Tabs 7.1 to 7.4,

Schedules 63-65

Summary of Capital Expenditures and CIAC

88.1 Please extend each of Table 6.2-1 Approved, Actual and Forecast Mainland Capital Expenditures, Table 6.2-2 Approved, Actual and Forecast Vancouver Island Capital Expenditures, Table 6.2-3 Approved, Actual and Forecast Whistler Capital Expenditures, and Table 6.2-3 Approved, Actual and Forecast Fort Nelson Capital Expenditures to include 2009 and 2008 actual amounts by completing the following:

	2008 Actual	**2009 Actual**	**2010 Approved**	**2010 Actual**	**2011 Approved**	**2011 Projected**	**2012 Forecast**	**2013 Forecast**
<u>Sustainment Capital</u>								
Meter Recalls/Exchange								
Transmission System Reinforcements/Integrity and Reliability								
Distribution Reinforcements/Integrity and Reliability								
Distribution Mains and Service Renewals and Alterations								
<u>Growth Capital</u>								
New Customer Mains								
New Customer Services								
New Customer Meters								
<u>Other</u>								
Equipment								
Facilities								
IT								
Subtotal								
<u>Contributions in Aid of Construction</u>								
Total Regular Capital								

Response:

The 2008 and 2009 Actual amounts for FEI, FEVI, FEW and Fort Nelson are included in the tables below:

Approved, Actual and Forecast Mainland Capital Expenditures

	2008 Actuals	2009 Actuals	2010 Approved	2010 Actuals	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
Sustainment Capital								
Meter Recalls/Exchanges	11,563	14,479	18,178	19,126	19,055	19,525	20,668	21,272
Transmission System Reinforcements / Integrity and Reliabililty	13,308	12,022	9,546	9,771	8,663	8,663	20,350	24,386
Distribution System Reinforcements / Integrity and Reliabililty	8,136	8,593	7,900	5,198	6,250	6,750	7,170	7,610
Distribution Mains and Service Renewals and Alterations	9,400	12,447	10,060	11,342	9,810	11,370	17,330	21,845
	42,407	**47,541**	**45,684**	**45,437**	**43,778**	**46,308**	**65,517**	**75,114**
Growth Capital								
New Customer Mains	10,991	6,140	8,807	4,538	9,306	5,738	6,124	6,497
New Customer Services	17,984	12,094	14,722	13,874	15,940	11,175	12,044	12,903
New Customer Meters	3,314	1,503	1,588	1,905	1,728	1,782	1,965	2,105
Biomethane/NGV	-	-	-	-	-	7,004	7,078	7,378
	32,288	**19,737**	**25,117**	**20,317**	**26,974**	**25,699**	**27,211**	**28,883**
Other								
Equipment	2,996	6,640	2,973	3,434	2,634	2,664	3,310	2,930
Facilities	1,988	2,805	3,737	4,177	4,212	4,138	8,424	4,124
IT	10,468	14,245	16,000	12,418	16,000	16,000	18,000	18,000
	15,452	**23,690**	**22,710**	**20,029**	**22,845**	**22,802**	**29,734**	**25,054**
Subtotal	**90,148**	**90,968**	**93,511**	**85,783**	**93,597**	**94,809**	**122,462**	**129,051**
Contributions in Aid of Construction								
	(11,291)	**(3,678)**	**(4,024)**	**(3,922)**	**(3,929)**	**(6,227)**	**(5,341)**	**(5,399)**
Total Regular Capital	**78,856**	**87,289**	**89,487**	**81,861**	**89,669**	**88,582**	**117,121**	**123,652**

Approved, Actual and Forecast Vancouver Island Capital Expenditures

	2008 Actuals	2009 Actuals	2010 Approved	2010 Actuals	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
Sustainment Capital								
Meter Recalls/Exchanges	567	907	1,492	1,134	1,496	1,188	1,215	1,250
Transmission System Reinforcements / Integrity and Reliabililty	5,178	5,282	5,045	3,836	7,868	7,868	8,098	6,328
Distribution System Reinforcements / Integrity and Reliabililty	1,111	1,131	1,520	991	2,315	2,315	2,685	935
Distribution Mains and Service Renewals and Alterations	2,065	1,423	1,000	1,156	1,000	1,326	4,276	5,646
	8,922	**8,743**	**9,057**	**7,117**	**12,679**	**12,697**	**16,274**	**14,159**
Growth Capital								
New Customer Mains	5,915	2,586	2,725	1,836	2,966	2,553	2,757	2,922
New Customer Services	7,072	5,743	5,940	5,309	6,459	4,517	4,926	5,270
New Customer Meters	754	588	540	430	582	440	480	513
	13,741	**8,917**	**9,206**	**7,575**	**10,006**	**7,510**	**8,163**	**8,705**
Other								
Equipment	121	1,335	1,615	1,181	1,500	1,391	3,073	3,591
Facilities	502	681	291	400	141	343	439	616
IT	1,367	1,789	1,500	1,473	1,500	1,500	2,000	2,000
	1,990	**3,805**	**3,406**	**3,054**	**3,142**	**3,234**	**5,512**	**6,207**
Subtotal	**24,653**	**21,465**	**21,669**	**17,746**	**25,827**	**23,441**	**29,948**	**29,070**
Contributions in Aid of Construction								
	(1,281)	**(18,077)**	**(442)**	**(371)**	**(448)**	**(487)**	**(426)**	**(431)**
Total Regular Capital	**23,373**	**3,388**	**21,226**	**17,374**	**25,379**	**22,953**	**29,523**	**28,639**

Approved, Actual and Forecast Whistler Capital Expenditures

	2008 Actuals	2009 Actuals	2010 Approved	2010 Actuals	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
Sustainment Capital								
Meter Recalls/Exchanges	39	16	27	44	27	41	41	42
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	-	-	10	45	-	-	-	-
Distribution Mains and Service Renewals and Alterations	94	319	82	27	84	94	88	81
	133	**335**	**120**	**116**	**111**	**134**	**129**	**123**
Growth Capital								
New Customer Mains	205	97	51	219	35	218	223	227
New Customer Services	167	214	97	122	68	48	52	53
New Customer Meters	19	40	14	3	9	4	5	5
	391	**351**	**163**	**344**	**112**	**270**	**279**	**285**
Other								
Equipment	57	60	18	5	17	17	20	60
Facilities	-	-	53	15	25	25	290	13
IT	-	-	-	-	-	-	-	-
	57	**60**	**71**	**20**	**42**	**42**	**310**	**73**
Subtotal	**581**	**746**	**353**	**480**	**265**	**446**	**718**	**481**
Contributions in Aid of Construction								
	(174)	**(36)**	**-**	**(5)**	**-**	**-**	**-**	**-**
Total Regular Capital	**407**	**710**	**353**	**475**	**265**	**446**	**718**	**481**

Approved, Actual and Forecast Fort Nelson Capital Expenditures

	2008 Actuals	2009 Actuals	2010 Approved	2010 Actuals	2011 Approved	2011 Projected	2012 Forecast	2013 Forecast
Sustainment Capital								
Meter Recalls/Exchanges	-	-	3	3	2	2	2	2
Transmission System Reinforcements / Integrity and Reliabililty	6	174	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	56	69	729	325	2,711	2,661	340	160
Distribution Mains and Service Renewals and Alterations	2	2	69	17	63	63	63	33
	63	**245**	**801**	**345**	**2,776**	**2,726**	**405**	**195**
Growth Capital								
New Customer Mains	5	7	11	23	11	11	12	12
New Customer Services	19	21	22	32	13	48	47	53
New Customer Meters	9	5	4	10	5	6	6	6
	34	**34**	**37**	**65**	**29**	**65**	**65**	**71**
Other								
Equipment	-	33	-	-	8	8	10	10
Facilities	-	-	-	-	-	-	129	-
IT	-	-	-	-	-	-	-	-
	-	**33**	**-**	**-**	**8**	**8**	**139**	**10**
Subtotal	**97**	**312**	**838**	**410**	**2,813**	**2,799**	**609**	**276**
Contributions in Aid of Construction								
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Regular Capital	**97**	**312**	**838**	**410**	**2,813**	**2,799**	**609**	**276**

88.2 Please explain why there is no amortization determined for the period in Section 7.4, Schedules 63-65 for Fort Nelson.

Response:

Amortization of the CIAC in Fort Nelson was inadvertently excluded. The amount that should have been shown for amortization 2011 is $29,000 in 2012 and $34,000 in 2013.

This correction will be reflected in the financial schedules when Fort Nelson provides an Evidentiary Update.

88.3 Please explain why there is no amortization related to Biomethane is determined for the period in Section 7.1, Schedules 63-65, yet amortization is shown in Table J-4 of Appendix J.

Response:

The forecast provided in Appendix J of the Application reflects the correct CIAC and amortization expense pertaining to the Biomethane Upgrader. The CIAC for the Biomethane Upgrader ($516,000 new plus $50,000 transferred from Lions Gate project) on Schedules 63, 64, and 65 of Section 7.1 was inadvertently embedded in the Distribution Contributions. As a result, amortization associated with the Biomethane Upgrader of $6,000 is embedded in Line 20 of Schedule 63 (Section 7.1).

The revised financial schedules reflecting the appropriate categorization and amortization of the Biomethane Upgrader CIAC will be submitted when FEI files an Evidentiary Update with no effect on rate base or rates.

89.0 Reference: 13 Month Adjustment

Exhibit B-1, Application, Section 6.1.6, p.328; Section 7, Tabs 7.1 to 7.4,

Schedules 39-41

Plant Additions and Retirements

A 13 Month Adjustment is calculated and included in rate base for the CCE Project for FEI – Mainland, FEVI, and FEW for 2012. FEI-Mainland also includes a 13 Month Adjustment for the Tilbury Land purchase and FEVI includes a 13 Month Adjustment for the Victoria Regional office CPCN for 2012. However, no adjustment is made for 2013.

89.1 Please provide supporting calculations for the 13 Month Adjustments for these major projects that are included in Schedules 39-41 for each utility in Section 7, Tabs 7.1 to 7.4.

<u>Response:</u>

The following tables provide the details for the calculation of the 13 month adjustment for 2011 and 2012 for FEI, FEVI, FEW and Fort Nelson by major project.

FEI - 2011	In Service Date	In Service Amount		13 month Adjustment
Kootenay River	1-Nov-11	$ 7,082	(3/13) - .5	$ (1,907)
Fraser River	1-Nov-11	$ 36,281	(3/13) - .5	(9,768)
				$ (11,675)
FEI - 2012				
CCE	1-Jan-12	$ 81,134	(13/13) - .5	$ 40,567

FEVI - 2011				
Mt. Hayes LNG	31-May-11	$ 212,962	(8/13) - .5	$ 24,573
FEVI - 2012				
CCE	1-Jan-12	$ 7,851	(13/13) - .5	$ 3,926
Victoria Office	1-Oct-12	14123	(4/13) - .5	(2,716)
				$ 1,210

FEW - 2012				
CCE	1-Jan-12	$ 222	(13/13) - .5	$ 111

Fort Nelson - 2011				
Muskwa River	1-Nov-11	$ 3,015	(3/13) - .5	$ (812)

89.2 Please confirm there is no forecast for 13 Month Adjustments for 2013 as there are no major projects coming into service in 2013. Does FEU expect on average the additions will occur by mid-year?

Response:

The FEU confirm that there is no 13 month adjustment to Rate Base for FEI, FEVI, FEW and Fort Nelson in 2013. In this Application, the FEU have not forecast any major projects to come into service in 2013. The FEU expect that on average, the additions to Gas Plant in Service will occur by mid-year.

90.0 Reference: Exhibit B-1, Figure 6.2-4, p. 342

Projected Trend in Sustainment Capital

90.1 Does the projected future trend in sustainment capital spending include a portion for larger capital projects that will likely be subject to a CPCN approval process?

<u>Response:</u>

Yes. As the projected future trend in sustainment capital is based on the potential replacement of all gas system assets, this trend includes larger capital projects that will be subject to the CPCN approval process. Given that assets will be replaced only as necessary and could be implemented on a program basis or as larger discrete projects, the sustainment capital budget will likely fluctuate from year to year but is generally expected to follow the projected trend.

91.0 Reference: Exhibit B-1, pp. 344, 346 - 349

Transmission System Reinforcement, Integrity & Reliability Capital – Mainland

FEU has forecast capital expenditures related to transmission system reinforcements and improvements to integrity and reliability as increasing from $8,663 thousand in 2011, to $20,350 thousand in 2012, and $24,386 thousand in 2013. On pages 346 to 349, FEU has identified a number of programs related to the forecast capital expenditures, some of which are ongoing and some of which are new. The new programs identified appear to account for approximately half of the proposed increase.

91.1 Please provide a detailed explanation of the projects and programs responsible for at least 80% of the increase in expenditures in 2012 and 2013.

Response:

Table 6.2-6 on page 344 of the Application (Exhibit B-1) sets out the total forecast capital requirements for the Mainland Transmission System for a total of $20.4 million in 2012 and $24.4 million in 2013. These amounts represent an increase of $11.7 million in 2012 and $15.7 million in 2013, over the 2011 approved and projection.

The following table sets out the programs and projects that contribute to approximately 80 percent of the forecast increases over 2011. These programs and projects are grouped into those already described on pages 347-349 of the Application (Exhibit B-1), and those that are described further below.

Incremental Mainland Transmission System Reinforcements / Integrity and Reliability Capital Requirements [$ Thousands]

	2011 Approved	2012 Forecast	2013 Forecast
Totals per Exhibit B-1, Table 6.2-6	8,663	20,350	24,386
Incremental increase over 2011 approved		11,687	15,723
80 percent of incremental increase		9,350	12,578

	2011 Approved	2012 Forecast	2013 Forecast
Projects and multi-year programs with cost over $1 million already described in Exhibit B-1			
Compressor station control upgrade	560	450	885
Interior transmission system valve replacement	900	2,360	2,160
Major inspection of pipelines	626	1,532	1,342
Physical security improvement (pipeline valve facilities)	200	1,650	1,412
Coastal Transmission System valve remote automation		2,000	2,000
Pipeline inline inspection improvement			1,500[15]
Seismic upgrades			1,000[16]
Depth of cover restoration on aging pipelines (Interior Transmission System)		1,000	5,000
Projects and multi-year programs described further below			
Physical security improvement (compression facilities)		450	459
Langley compressor station fire suppression system upgrade		300	
SCADA RTU upgrade		428	437
Depth of cover restoration on aging pipelines (Coastal Transmission System)		1,200	
Total increase over 2011 explained		11,370	16,195

The following are incremental 2012 and 2013 projects and programs not yet discussed in Exhibit B-1 pp. 347-349:

[15] In Exhibit B-1, on page 348, this amount was incorrectly referred to as occurring in 2012.
[16] In Exhibit B-1, on page 349, this amount was incorrectly referred to as occurring in 2012.

- Physical security improvement (compression facilities) – with the planned adoption by the Oil and Gas Commission of CSA Z246.1-09, *Security management for petroleum and natural gas industry systems*, security upgrades such as access control, vehicular barricade, active video monitoring and alarms, and improved fencing, etc. are planned for the critical and vulnerable assets on the transmission systems including compression facilities. These upgrades will occur on an on-going basis in response to regular security criticality, threat and vulnerability assessments and have an annual forecast of approximately $450 thousand.

- Fire suppression system upgrade at Langley compressor station – the current system is found to be deficient in coverage for existing building and equipment; this project will also provide coverage to new piping and equipment storage buildings. The upgrade is scheduled for installation in 2012 at a cost of $300 thousand.

- Remote terminal units (RTU) replacement – the RTUs and the associated communication systems installed throughout the gas systems on the Mainland to communicate flow signals to the Supervisory, Control and Data Acquisition (SCADA) system in Gas Control are now technically obsolete. The replacement program will be implemented over a 5-year period with an annual expenditure of just over $400 thousand.

- Increase depth of cover of Coastal Transmission System pipeline segment – this project involves the replacement in 2012 of a pipeline segment located in cultivated farmland found to have shallow depth of cover. The cost of the project is estimated to be over $1 million.

92.0 Reference: Meter Recalls and Exchanges

Exhibit B-1, Application, Section 6.2.2.3, p.345

Meter Activity Levels

"Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, provided us with the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed the Mainland to temporarily reduce the number of meter recalls from between 40,000 to 50,000 meter recalls annually to a range between 25,000 to 35,000 recalls annually over the period 2006 - 2008. The reduction in the number of recalls brought the demographics of the meter fleet in line with a 20 year life expectancy, which provide customers with the cost benefits of previous investments in the fleet."

92.1 FEI Mainland meter recalls were reduced to 25,000 – 35,000 between 2006 and 2008. Please explain how the recall frequency is calculated, and how the recall process is administered, such that the meter recalls have almost doubled in four years.

<u>Response:</u>

FEI residential meter recall activity is designed to ensure compliance of the meter fleet with the regulations set forth by Measurement Canada in accordance with the *Electricity & Gas Inspections Act* of Canada. As such, FEI strategically manages its meter fleet to ensure continued reliability and cost effectiveness while meeting all the legal requirements of the federal government legislation. Provided below is a brief description of the process applied by the FEI to determine its annual residential meter recall activity level.

Prior to being shipped from an accredited manufacturer's facility, all new residential meters have a seal applied with an associated expiry date as defined according to Measurement Canada requirements. A year prior to the expiration of the seal, the meters are formed into homogeneous groups for the compliance sampling process to ensure the accuracy of the meters is within federally regulated tolerances. This is completed by first extracting a representative sample from the groups of meters which have been formed according to Measurement Canada's sampling specification LMB-EG-04. The sample meters are tested under strictly controlled conditions in FEI's certified test facility and the test data is analyzed using government mandated statistical methods. The test results are then used to determine if the meter group from which the sample was withdrawn is legally permitted to remain in service. The greater the level of error observed in the sampled meters, the shorter the allowable time period of the seal extension before the meter group must undergo further accuracy testing.

Where test results fail to meet Measurement Canada accuracy requirements, the meter group in question must be removed from the field the following year and replaced. At this time a determination is made whether the removed meters will be retired. In the event that a group of sampled meters is allowed only a short seal extension indicating the meter accuracy is close to reaching the maximum allowable error limit and the meter age is nearing the end of the average expected meter service life for residential meters, FEI will consider scheduling the meters for recall at a time during the seal extension period which minimizes the recall cost. Given the current average service life of 20 years observed through the compliance sampling process, approximately 1/20th or 5 percent of the fleet is scheduled to be removed annually in order to ensure the fleet continues to operate in a reliable and cost-effective manner.

Finally, the time period between 2006 and 2008 was unique from the perspective that FEI was transitioning from the relatively expensive practice of refurbishing meters after 14 years to the current practice of leaving them in the field until they reach the end of their useful life. Therefore, during this time period, recalls were temporarily reduced to allow meters that would previously be removed from the fleet for refurbishment, to remain in the field to the end of their service lives.

93.0 Reference: Transmission Systems Reinforcement, Integrity & Reliability Capital – Vancouver Island

Exhibit B-1, Application, Section 6.2.2.9, p.354

Trend in Capital Expenditures

93.1 FEVI

As shown in Table 6.2-8 above, the 2010 approved expenditures for Vancouver Island Transmission was $5.1 million. The actual expenditure was approximately $3.8 million. The decrease was primarily due to planned projects not materializing in the year.

The forecasts for transmission expenditures in 2012 and 2013 are $8.1 and $6.3 million, respectively as shown in Table 6.2-8 above.

93.2 FEVI's actual capital expenditures for 2010 were $3.8M compared to the approved amount of $5.1M. FEVI has indicated that the decrease is due to planned projects not materializing in the year. Although the 2010 expenditures came in well below the approved amount, the FEVI is forecasting the transmission expenditures to be $8.1M and $6.3M in 2012 and 2013 respectively. Why such an increase when 2010 actual expenditures were well below the approved amount?

Response:

The capital budget for the Vancouver Island Transmission system contains $2 million in contingency funding required for potential compressor failures and pipeline washouts. This contingency is a critical resource because the compressor units operate at a high load factor and the pipeline operates through mountainous terrain that is buffeted by frequent storms, particular during the winter season. A failure of either component of the Vancouver Island Transmission system could cause a significant disruption to service provided to customers on Vancouver Island and the Sunshine Coast. The $1.3 million decrease in planned expenditures in 2010 resulted primarily because there was no need to use the contingencies to recover from compressor failures or pipeline washouts. Other reliability requirements offset the unused contingency funding amount, which resulted in the reduction of the variance to $1.3 million.

The increase in the 2012 and 2013 forecasted transmission expenditures over 2010 actual expenditures are the result of three items:

- Mt. Hayes LNG Storage Facility projects – with the facility put into service in 2011, a number of miscellaneous continuous improvement projects with an annual expenditure of approximately $800 thousand are planned on a go-forward basis beginning in 2012.

- Compressor Unit Overhauls on the Vancouver Island System – a number of compressor units will reach the accumulated total running hours that trigger the need to complete major overhauls in 2012. The total cost to complete the overhauls is forecasted to be $1.5 million and will not be repeated in 2013.

- $2 million in contingencies required for potential compressor failures and pipeline washouts.

As the Vancouver Island Transmission system, installed in 1989, is relatively new, sustainment capital expenditures are not expected to increase in the intermediate term. Instead, a continued fluctuation in expenditures should be expected given the timing of major overhauls of compressor units, major pipeline inspections, and the need to budget for potential compressor failures and pipeline washouts.

94.0 Reference: Growth Capital Expenditures

Exhibit B-1, Application, Sections 6.2.3, pp.361-363 and pp. 365-370

Mains and Services Expenditures

94.1 FEI - Mainland

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year (2008-2010) historical ratio of 0.72 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 13.7 metres of new Main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Table 6.2-14: Approved, Actual and Forecast Mainland Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	112,136	81,259	116,166	100,724	105,395	109,623
Unit Costs ($/meter)	$ 79	$ 56	$ 80	$ 57	$ 58	$ 59
Expenditures ($000's)	$ 8,807	$ 4,538	$ 9,306	$ 5,738	$ 6,124	$ 6,497

Table 6.2-15: Approved, Actual and Forecast Mainland Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	5,952	6,629	6,166	6,361	6,656	6,923
Gross Customer Additions	9,336	12,770	9,672	10,194	10,667	11,095
Ratio of Service Additions to Gross Customer Additions	0.78	0.73	0.78	0.72	0.72	0.72
Activities (risers or services)	7,303	9,382	7,566	7,337	7,677	7,985
Unit Costs ($ per service - riser)	2,016	$ 1,479	2,107	$ 1,523	$ 1,569	$ 1,616
Expenditures ($000's)	$ 14,722	$ 13,874	$ 15,940	$ 11,175	$ 12,044	$ 12,903

94.2 Given the statement above and comparing Table 6.2-14 on Mainland Mains Expenditures and Table 6.2-15 on Mainland Services Expenditures there appears to be an anomaly in that the mains expenditures and gross customer additions/services are not trending in the same pattern from the 2010 actuals to the 2013 forecast. While the main expenditures are steadily rising, the gross customer additions are declining from the 2010 actuals. This would appear to be as a result of the sharp decrease in the # of meters of new main per service in 2010 (i.e. 9 meters, computed as Activities (meters) divided by Activities (risers or services)) compared to the three average of 13.7 meters used for 2011-2013 and the 2008 year of 19 meters.

FEI-Mainland indicates that the reason for the sharp decline was largely due to the downturn in the economy late 2008, a build up of new mains infrastructure in 2005-2008, lower new subdivision activity in 2009 and decreases in housing starts in 2009. Although the economy is recovering and real estate development is picking up, it is not at the same rate as in past years. The average 13.7 meters of new Main per new Service addition seems high compared to the actual 9 meters of 2010. Please explain why 13.7 meters is a reasonable estimate of new Main per new Service addition to use given the pace of recovery of the economy after the downturn in late 2008 is gradual and moderate.

Response:

The current methodology is reasonable and consistent with past practice. We believe using the three-year historical ratio smoothes out the annual fluctuations in the ratio by incorporating a reasonable range of historical data together with the most recent year's data.

There are generally some timing differences with respect to main and service installations such that service attachments may not be installed in the same year as the main. Typically, the main is installed first, followed by the installation of services over the next one to five years. The installation of the service depends on when the lot and building is ready for gas service and the success of the development. If economic conditions are unfavourable, there may be an extended delay (i.e. months, years) in the request for service installation compared to the main installation date. This gives rise to year-to-year fluctuations in the ratio of meters of new main per service addition. Over the longer term of three years these timing differences between main and service installations are reduced.

In our view, using the one-year data for the longer-term cycle of the mains and services relationship is inconsistent with past practice and does not recognize the longer historical relationship between the two installations. Therefore using historical and recent data together provides the best forecast.

94.3 FEVI

Mains Activity Levels

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year

(2008-2010) historical ratio of 0.81 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 12 metres of new main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Table 6.2-17: Approved, Actual and Forecast Vancouver Island Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	30,116	18,282	31,610	24,927	26,393	27,415
Unit Costs ($/meter)	$ 90	$ 100	$ 94	$ 102	$ 104	$ 107
Expenditures ($000's)	$ 2,725	$ 1,836	$ 2,966	$ 2,553	$ 2,757	$ 2,922

Table 6.2-18: Approved, Actual and Forecast Vancouver Island Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	2320	2,725	2430	2,415	2,557	2,656
Gross Customer Additions	2460	2,940	2582	2,564	2,714	2,820
Ratio of Service Additions to Gross Customer Additions	0.78	0.85	0.78	0.81	0.81	0.81
Activities (risers or services)	1,922	2,501	2,017	2,066	2,187	2,272
Unit Costs ($ per service - riser)	$ 3,091	$ 2,123	$ 3,202	$ 2,186	$ 2,252	$ 2,320
Expenditures ($000's)	$ 5,940	$ 5,309	$ 6,459	$ 4,517	$ 4,926	$ 5,270

94.4 Given the statement above and comparing Table 6.2-17 on FEVI Mains Expenditures and Table 6.2-18 on FEVI Services Expenditures there appears to be an anomaly in that the mains expenditures and gross customer additions/services are not trending in the same pattern from the 2010 actuals to the 2013 forecast. While the main expenditures are steadily rising, the gross customer additions are declining from the 2010 actuals. This would appear to be as a result of the sharp decrease in the # of meters of new main per service in 2010 (i.e. 7.3 meters, computed as Activities (meters) divided by Activities (risers or services)) compared to the three average of 12.0 meters (2008-2010) used for 2011-2013.

The reason for the sharp decline would be similar to FEI – Mainland, in that it was largely due to the downturn in the economy late 2008. Although the economy is recovering and real estate development is picking up, it is not at the same rate as in past years. The average 12.0 meters of new Main per new Service addition seems high compared to the actual 7.3 meters of 2010. Please explain why 12.0 meters is a reasonable estimate of new Main per new Service addition to use given the pace of recovery of the economy after the downturn in late 2008 is gradual and moderate.

Response:

Please refer to the response to BCUC IR 1.94.2.

94.5 FEW

Forecast mains activity levels, unit costs and resulting capital expenditure are difficult to forecast in Whistler due to the small volumes and wide year over year fluctuations. For 2009 and 2010 the average metres of main installed was 1,800 metres and we have assumed a similar level of activity for 2012-2013. Unit costs are generally higher in Whistler than in the Mainland and Vancouver Island as the install contractor completing mains and services work is located outside the Whistler service territory and includes a crew mobilization/travel charge in rates.

94.6 Although the forecasted level of activity for 2012-2013 is similar to 2009 and 2010, please summarize main and services expenditures similar to Table 6.2-14 and Table 6.2-15 for FEI-Mainland. Please complete the following tables for FEW:

Approved, Actual and Forecast FEW Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)						
Unit Costs ($/meter)						
Expenditures ($000's)						

Approved, Actual and Forecast FEW Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions						
Gross Customer Additions						
Ratio of Service Additions to Gross Customer Additions						
Activities (risers or services)						
Unit Costs ($ per service – riser)						
Expenditures ($000's)						

Response:

The tables are presented below:

FEW - Forecast Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	504	1,843	322	1,800	1,800	1,800
Unit Costs ($/meter)	$ 102	$ 119	$ 108	$ 121	$ 124	$ 126
Expenditures ($000's)	$ 51	$ 219	$ 35	$ 218	$ 223	$ 227

FEW - Forecast Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	36	37	23	18	19	19
Gross Customer Additions	36	30	23	18	19	19
Ratio of Service Additions to Gross Customer Additions	1.00	0.90	1.00	0.90	0.90	0.90
Activities (risers or services)	36	27	23	16	17	17
Unit Costs ($ per service - riser)	$ 2,601	$ 4,518	$ 2,757	$ 2,938	$ 3,026	$ 3,117
Expenditures ($000's)	$ 97	$ 122	$ 68	$ 48	$ 52	$ 53

Fort Nelson

Mains activity levels in Fort Nelson, are generally low and fluctuate widely from year to year depending on the local economy. Unit costs are difficult to forecast due to the small volume of activity. No major extensions are foreseen at this time. As with the other Utilities, all proposed main extensions are scrutinized through the main extension review test to determine if they are economic. For forecasting purposes the 2012 and 2013 expenditure was based on the 2011 projection inflated.

94.7 Similar to FEW, please summarize main and services expenditures similar to Table 6.2-14 and Table 6.2-15 for FEI-Mainland. Please complete the following tables for Fort Nelson:

Approved, Actual and Forecast Fort Nelson Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)						
Unit Costs ($/meter)						
Expenditures ($000's)						

Approved, Actual and Forecast Fort Nelson Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions						
Gross Customer Additions						
Ratio of Service Additions to Gross Customer Additions						
Activities (risers or services)						
Unit Costs ($ per service – riser)						
Expenditures ($000's)						

Response:

The tables for Mains and Services, respectively, are presented below:

Ft Nelson

	2010 Budget	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	170	1,237	168	200	200	200
Unit Costs ($/meter)	$ 65	$ 20	$ 66	$ 57	$ 58	$ 59
Expenditures ($000's)	$ 11	$ 23	$ 11	$ 11	$ 12	$ 12

	2010 Budget	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	18	21	12	23	22	24
Gross Customer Additions	N/A	19	N/A	37	35	38
Ratio of Service Additions to Gross Customer Additions	1.00	1.42	1.00	1.00	1.00	1.00
Activities (risers or services)	18	27	12	37	35	38
Unit Costs ($ per service - riser)	$ 1,200	$ 1,257	$ 1,125	$ 1,295	$ 1,334	$ 1,374
Expenditures ($000's)	$ 22	$ 32	$ 13	$ 48	$ 47	$ 53

95.0 Reference: Facilities and Equipment Capital – Mainland

Exhibit B-1, Application, Section 6.2.4.1, pp. 371-372

Facilities

North Vancouver Muster Station

> In 2012, Facilities also proposes to purchase land for the North Vancouver Muster for an estimated $2 million. This estimate is based on the requirement of approximately .5 acre at the current market rate of $85 square foot. The muster is currently leased and, due to an expansion for the Landlord, we will be forced out and not able to operate from this site. This site is a critical for the Operations department as it provides operational support for the North and West Vancouver areas and is on the north side of the Burrard Inlet to ensure resources are always available for this area in the event of an emergency. The Landlord has provided reasonable timelines for their expansion and Facilities has been exploring alternatives for two years with no success due to the limited industrial real estate market.

95.1 The estimated land purchase for the North Vancouver Muster Station is $2 million and is based on a current market rate of $85 per square foot and a requirement of 0.5 acres or approximately 21,780 square feet. Please provide evidence of 5 recent sales of similar property in the same area in North Vancouver that the FEI-Mainland plans to purchase land for the Muster Station.

Response:

Listed below is a summary of industrial land sales in the property area of North Vancouver that are similar to the one that FEI-Mainland plans to purchase for a Muster Station. The comparables provided are not all "recent sales" and date back as far as 2007 because there have been very few land sales in this area. There is no industrial land in West Vancouver, and North Vancouver industrial land is extremely scarce. The Port Authority controls all of the waterfront industrial property and the remaining industrial property is under demand pressure for retail and office developers who will pay a higher price for the land. The lack of recent comparables demonstrates the lack of available industrial land for this area and the demand of a higher market rate. FEI-Mainland believes the forecast of $85 per square foot is a realistic budget based on the current market and demand for industrial land in North Vancouver.

Land Comparables – North Vancouver
Prepared by CB Richard Ellis Limited
June 14, 2011
Page 1 of 1

Date	Transaction Name	City	Land Use	Size (acres)	Size (SF)	Price	Price/Acre	Price/Sq.Ft.
January 13, 2007	Lot J Gostic Place	North Vancouver	Industrial	0.451	19,646	$995,000.00	$2,206,208.00	$51.00
January 22, 2007	219 East 1st Street	North Vancouver	Industrial	0.960	4,203	$440,000.00	$4,583,333.00	$105.00
October 14, 2009	22 Gostic Place	North Vancouver	Industrial	0.451	19,646	$1,625,000.00	$3,603,104.00	$82.72
October 15, 2009	61 Bewicke Avenue	North Vancouver	Industrial	0.591	25,744	$1,250,000.00	$2,134,440.00	$49.00
October 20, 2010	212 Brooksbank Avenue	North Vancouver	Industrial/Retail	1.410	61,419	$7,665,000.00	$5,436,170.00	$124.80
April 27, 2011	20 Fell Avenue*	North Vancouver	Industrial	0.570	25,000	$2,000,000.00	$3,484,800.00	$80.00

* Offer accepted.

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Facilities and Equipment Capital Expenditures

Table 6.2-21: Approved, Actual and Forecast Mainland Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	2,973	3,434	2,634	2,664	3,310	2,930
Facilities	3,737	4,177	4,212	4,138	8,424	4,124
	6,710	7,611	6,845	6,802	11,734	7,054

95.2 FEI-Mainland is forecasting an increase in Facilities Capital expenditures of approximately $4,286,000 from the projected 2011 expenditures. $2 million of this increase is estimated for the land in North Vancouver for the Muster Station and $1.4 million is estimated for the Penticton Meter Shop and Langley Compressor Station Muster addition. The remaining difference is then approximately $900,000. This $900,000 does not appear to be related to normal or recurring facility expenditures as it is over and above the projected and forecasted facility expenditures for 2011 and 2013 respectively. Please provide an explanation and supporting evidence for the approximate additional $900,000 in forecasted facility expenditures for 2012.

Response:

The additional forecasted facility expenditures in 2012 not related to normal or recurring facility expenditures is $1 million over and above the 2011 and 2013 forecasted facility expenditures. The requested increase is a result of the following items:

- **$500,000 North Vancouver New Structures or Building Modification -** The North Vancouver Muster is a critical facility for Operations as it provides operational support for the North and West Vancouver areas and is on the north side of the Burrard Inlet to ensure resources are always available for this area in the event of an emergency. FEI-Mainland proposes to purchase land for this facility as identified in Application (Exhibit B-1), Section 6.2.4.1, pages 371-372 Facilities. In addition to the cost of land, FEI-Mainland has budgeted $500,000 to allow for either two new structures or modifications if a building(s) existed. Operations' requirements for a muster facility are a secured compound with office space, closed shed and yard storage.

- **$500,000 Surrey Operations Densification -** As identified in Application, Section 6.2.4.1, pages 371-372 Facilities, FEI-Mainland proposes to increase the seating capacity for the Surrey Operations site. In addition to the furniture requirement, FEI-Mainland has budgeted $500,000 for infrastructure increases (such as electrical, HVAC) to allow for the seating increases.

FEI-Mainland believes this increase in forecasted facility expenditures for 2012 is warranted and benefits the company and customer in ensuring availability of critical facilities and preventing increases in O&M costs.

96.0 Reference: IT Expenditures

Exhibit B-1, Application, Section 6.2.5, pp. 375-378

2010 IT Projects

IT Capital Expenditures

Table 6.2-25: Approved, Actual and Forecast IT Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
IT Capital - Mainland	16,000	12,418	16,000	16,000	18,000	18,000
IT Capital - Vancouver Island	1,500	1,473	1,500	1,500	2,000	2,000
IT Capital - Total	17,500	13,891	17,500	17,500	20,000	20,000

The 2010 actual amount of $13.9 million for both Vancouver Island and the Mainland in 2010 against the budget of $17.5 was primarily due to the approval of the Customer Care Enhancement (CCE) CPCN which refocused key IT and business resources that otherwise would have been allocated to other initiatives. At the time of budget planning, this CPCN was not yet approved therefore the budget was created assuming access to all required resources. Additionally, several key projects had their planned spend profile deferred between fiscal year 2010 and 2011 due to unplanned competing demands on scarce business resources and prolonged vendor negotiations. 2011 spend is projected to be $17.5 million based on the rebaselined plan factoring in CCE and maximizing the available resources.

In 2012 and 2013, IT expenditures are forecast to be $20 million annually, which will allow for the replacement, acquisition, and implementation of IT hardware, software, and related infrastructure.

96.1 There is a significant decrease in IT expenditures in 2010 compared to the amount approved. The FEU have explained in the above excerpt that this was due to the reallocation of pre-approved IT expenditures to the CCE CPCN project, which was not yet approved at the time of filing of the 2010-2011 RRA. With the CCE CPCN now approved, how much of the IT projects that were contemplated for 2010 but did not materialize in 2010 are allocated to projected 2011 and forecasted 2012 and 2013 IT expenditures? Also, please indicate what the total impact of these incomplete projects had on ROE and rates in 2010 and 2011?

Response:

There were no pre-approved 2010 IT expenditures reallocated to the CCE CPCN. Only IT personnel were redirected to support the execution of the CCE CPCN. Also, because of the scope of the CCE Project, any potential projects that would have impacted SAP and supporting systems were deferred as to not impact the CCE Project implementation. Of the 70 projects that made up the initial 2010 IT Project Portfolio, 12 projects were deferred until after the completion of the CCE Project in early 2012. In order to be considered for 2012 and 2013 IT Portfolios, all of these projects will go through the established IT Portfolio Selection process 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.

There was no impact on rates in 2010 and 2011 based on these projects being deferred since rates were set prior to their deferral. The deferral of these projects did contribute to a lower actual rate base in 2010 than what had been approved. As discussed in response to BCUC IR 1.3.1, when all cost of service items (including the variance in IT spending) and revenues are considered, the actual return on equity for FEI in 2010 was 9.42 percent as compared to the approved return on equity of 9.50 percent.

96.2 How much of the 2010 approved IT expenditures were allocated to the CCE CPCN project in 2010?

Response:

Please refer to the response to BCUC IR 1.96.1.

IT Projects

> A second requirement for IT expenditures is the need to sustain and upgrade hardware and software. Keeping up with evolving technologies is a challenge for all companies as the frequent introduction of new infrastructure and new application versions have become commonplace throughout the IT industry. On occasion, the turnaround from new to discontinued application
>
> versions can be as short as 18 months. Larger application vendors (i.e. GE Smallworld and SAP) have scheduled version updates that incorporate new changes and additional functionality to the application, incorporate correction patches into the core system and take advantage of improvements in infrastructure. Many software and hardware vendors typically abandon older versions and withdraw support as their new version becomes available. Consequently,

96.3 Per the statement above, an application's life could be as short as 18 months. Per Table 6.25-25 it would appear that IT applications and infrastructure are being replaced annually, which is faster than the shortest estimated life cycle of an IT application. Please explain why there appears to be a discrepancy with respect to the life cycle of an IT application.

Response:

The FEU assume that the statement above, "Per Table 6.25-25 it would appear that IT applications and infrastructure are being replaced annually" was meant to refer to Table 6.2-25. Table 6.2-25 does not indicate that specific IT applications and infrastructure are being replaced annually; each year the composition of the IT projects that make up the annual spending will change, although the annual totals may remain the same.

To clarify the statement, "the turnaround from new to discontinued application versions can be as short as 18 months", it is not the FEU's practice to implement new technology versions with each introduction from the vendor, particularly if the time lapse between versions is short. The FEU only update based on business need and/or support requirements such as the vendor advising that support for a particular version of software that FEU has installed will no longer be available. Vendors typically support multiple versions of their software at any point in time. For IT Hardware, we have definitive schedules for replacement based on assessed asset life. As an example, individual servers are upgraded every five years but we have an annual refresh program for server replacements. This allows for the FEU servers to be replaced in a scheduled and predictable fashion without undue risk to the organization.

96.4 Please provide in detail the IT projects planned with estimated costs contemplated and included in FEU's IT Project Portfolio. Please also provide an explanation on how each project aligns with the FEU's strategic goals and how each project supports the achievement of organizational goals and priorities.

Response:

The FEU understand this question to be about the 2010 IT projects. A discussion of the 2012 and 2013 IT projects is included in response to BCUC IRs 1.97.1 through 1.97.4.

The FEU's IT Project Portfolio in 2010 estimated and expended approximately $14 million across three key organizational priorities:

- Introducing or enhancing new capabilities in individual business units or the enterprise;
- Technology sustainment and upgrading; and

- Security / risk mitigation.

In the paragraphs below, the FEU describe the spending in each of these major categories of projects, with more information on specific significant projects included in each category. Other than the five projects identified below which make up just over 40 percent of the total spend, generally IT projects tend to be many with a dollar value less than $500 thousand. For this reason the remaining projects have been grouped for discussion under the general categories only.

In the first category of introducing or enhancing new capabilities, $5.878 million was spent amounting to 43 percent of the total 2010 expenditures. The 32 projects within this category sought to enable business process change. As the operating departments within the Companies continually seek to identify more efficient or effective processes as well as to permit the Companies to preserve efficiencies that have been attained, investments in information technologies were required. In addition, IT capital expenditures were made to enable the operating departments to comply with changing regulations and external requirements demanding compliance. An example of this type of project that was identified in annual reporting to the Commission is the Transmission Plant Maintenance System Project Phase 1. This project aligned the respective Gas Companies' plant maintenance business processes, data management and reports driving the consolidation on a common application along with Gas Distribution Plant Maintenance. The total cost of Phase 1 in 2010 was $1.285 million.

In the second category of technology sustainment and upgrading, $4.863 million was spent amounting to 35 percent of the total 2010 expenditures. The 24 projects within this category enabled the prudent sustainment and upgrading of the FEU's hardware and software. As detailed in the response to BCUC IR 1.96.3, the FEU continually balance the need to replace IT assets based on asset life, sustainment requirements and business need. Examples of these types of projects previously identified in annual reporting to the Commission are the IT Network Evergreening, 2010 Desktop Refresh and the Microsoft Vista Upgrade projects. The IT Network Evergreening project was a part of the annual network infrastructure replacement program that ensures network switches, routers and other devices are replaced in accordance with their assessed asset life. In 2010, this project spent $204 thousand. The 2010 Desktop Refresh project was a part of the annual infrastructure replacement program targeting desktops and laptops also in accordance with their assessed asset life. In 2010, this project spent $1.18 million. The Microsoft Vista Upgrade project was the continuation of the 2009 project with the end-state of upgrading all of the FEU desktop and laptop computers with the Microsoft Vista system platform from the dated Microsoft XP platform in order to ensure supportability. 2010 costs amounted to $309 thousand.

Finally, in the third category of security / risk mitigation, $3.049 million was spent amounting to 22 percent of the total 2010 expenditures. The 3 projects within this category enabled the FEU's response to the growing IT security threat and to mitigate identified IT risks. As detailed in the Application (Exhibit B-1), Section 6.2.5, pages 377, a dramatic shift in security threats began early in 2001 primarily due to the increased use of Internet e-mail functionality and the escalating threat of external hackers. These security threats have grown to exploit weaknesses in all areas of network and software applications. An example of this type of project that was identified in annual reporting to the Commission is the Disaster Recovery Project. This project was designed to ensure the availability of an alternate data centre to run critical business systems should such an event impact the primary data centre at Surrey Operations. 2010 costs amounted to $2.796 million.

97.0 Reference: Exhibit B-1, pp. 375 - 376

IT Expenditures – Key Drivers

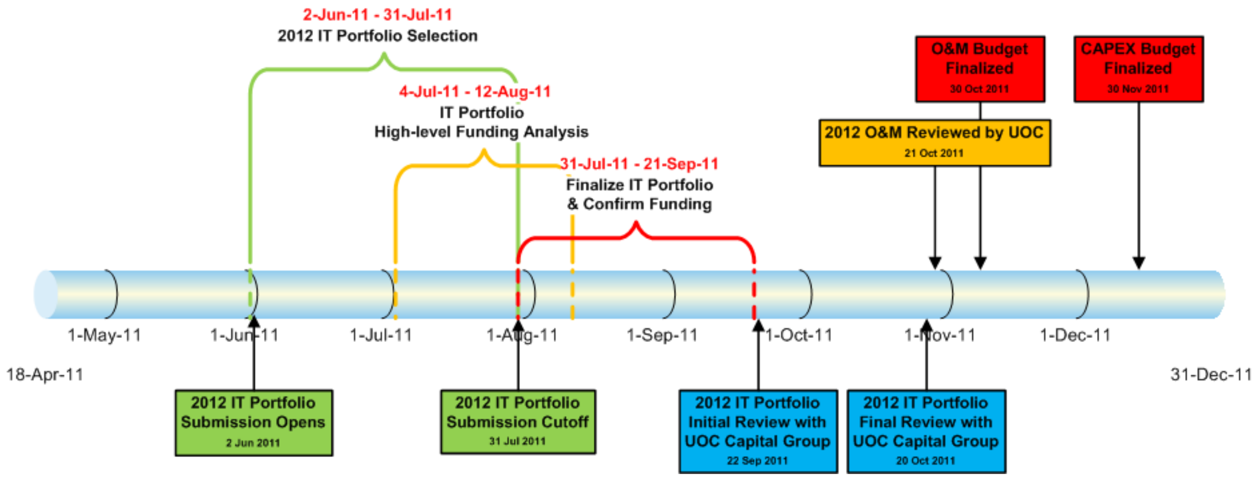
On page 376, FEU states: *"A key driver of IT capital expenditures is changing business process needs. The operating departments within the Company continually seek to identify more efficient or effective processes as well as to permit the Company to preserve efficiencies that have been attained. As a result, investments in information technologies are required. In addition, IT capital expenditures are made to enable the operating departments to comply with changing regulations and external requirements that demand compliance."*

97.1 Please provide a breakdown of the forecast 2012 and 2013 capital expenditures by key driver: (i) technology sustainment and upgrading; (ii) security; (iii) disaster recovery and risk mitigation; and (iv) introducing or enhancing new capabilities.

Response:

As detailed in the Application (Exhibit B-1), Section 6.2.5, pages 377, the FEU's IT Portfolio Selection cycle takes place annually starting in late Q2 through Q3 of the year prior to which the projects would be launched. The Portfolio Selection cycle follows on the corporate budgeting process once the IT capital budget is established as indicated in the timeline diagram below.

Portfolio Selection activities start with projects being collected and evaluated against corporate goals using the criteria and weighting methods. The Portfolio is prioritized to provide a baseline. Financial, dependency and resource analysis are applied and then the Portfolio is balanced against these constraints (during the High-level Funding Analysis and Finalize and Confirm Funding stages). A Portfolio can pass through much iteration prior to finalization. Once finalized, the Portfolio will have clear alignment to corporate goals and key drivers.



As such, it is not until the end of Q3 of 2011 that the portfolio selection will have finalized the composition and expenditure forecast of the 2012 Portfolio; likewise Q3 2012 for the 2013 Portfolio.

However, based on the FEU's current view of the candidate projects for 2012 and 2013 that have yet to be processed through Portfolio Selection, the current forecast of projects that will be evaluated for selection over the two years are detailed in the table below, by driver. It is likely that the composition and therefore the forecast per driver will change in accordance with the yearly Portfolio Selection.

Driver	**2012** (in thousands)	**2013** (in thousands)
Technology Sustainment and Upgrading	$ 6,945.5	$11,498.0
Security and Risk Mitigation (including Disaster Recovery)	$1,615.0	$845.0
Introducing or Enhancing New Capabilities	$17,605.1	$11,483.4
Total	**$26,165.6**	**$23,826.4**

97.2 Please provide an actual example where an investment in information technology during the period 2012 - 2013 will preserve the efficiencies or the effectiveness of processes.

Response:

As stated in the response to BCUC IR 1.97.1, the IT projects for 2012 and 2013 have not yet been evaluated and selected. However, based on the FEU's current view of the candidate projects for 2012 and 2013 that have yet to be processed through Portfolio Selection, an example of a project targeting the efficiencies or effectiveness of processes is the Budgeting and Consolidation initiative. Evolving business needs are highlighting the need and urgency to review the FEU's existing financial planning and consolidation processes, with the intent to streamline and improve their efficiency and effectiveness. Increasing regulatory planning requirements and quarterly and annual reporting requirements are highlighting the need to ensure the FEU's financial planning processes and systems can provide the information required in a timely fashion with a high degree of accuracy.

97.3 Please provide an actual example where an investment in information technology during the period 2012 - 2013 will enable an operating department to comply with changing regulations.

Response:

As stated in the response to BCUC IR 1.97.1, the IT projects for 2012 and 2013 have not yet been evaluated and selected. Furthermore, it is important to note that compliancy drivers are not all the same year over year and that when compliancy rules or regulations change, there is usually a relatively short window to address them. While the FEU may not have a concrete example of a changing regulation project for 2012 - 2013, that is not to say there will not be a change in that timeframe to which we will need to respond. As an example, the FEU may need to introduce a project to reverse the Harmonized Sales Tax changes made in 2010 and reintroduce the Provincial Sales Tax model based on a government decision.

97.4 Please provide an actual example where an investment in information technology during the period 2012 - 2013 will enable an operating department to comply with external requirements that demand compliance.

Response:

As stated in the response to BCUC IR 1.97.1, the IT projects for 2012 and 2013 have not yet been evaluated and selected. Furthermore, it is important to note that compliancy drivers are not all the same year over year and that when compliancy rules or regulations change, there is usually a relatively short window to address them. While the FEU may not have a concrete example of a changing regulation project for 2012 - 2013, that is not to say there will not be a change in that timeframe where we will need to respond.

However, an example of a past project that was initiated in order to comply with external requirements demanding compliance was the Learning Management System project. The outcome of this project enabled the FEU to comply with the new competency and training requirements of CSA Z662-07, Annex N. This project enabled the operating departments to document the training and competency requirements for each employee, and then maintains the appropriate records of education, training and qualifications.

98.0 Reference: Exhibit B-1, p. 378

IT Expenditures – 2012 and 2013 Forecasts

"The Company is forecasting an increase of $2.0 million for the Mainland and $500 thousand for Vancouver Island for 2012 from the 2011 total of $16.0 million and $1.5 million respectively, with 2013 held at that level. This increase is based on enabling several robust technology roadmaps created in 2010 and 2011 in addition to satisfying pent-up demand from restrictions on the execution of several IT projects other than the CCE CPCN."

98.1 Please clarify which technology roadmaps FEU is referring to and the related expenditures forecast for 2012 and 2013.

<u>Response:</u>

A technology roadmap describes the transformation path for IT assets (applications, systems and skills) over an extended period of time. At the FEU, we have been developing our technology-roadmap based approach over the last few years to better reflect IT alignment with longer term vision associated to business capability, for example, asset management, record management. etc.

Technology roadmaps are a construct of the wider FEU's enterprise architecture approach used to drive sustainable improvement and update to existing IT enabled business services. Technology Roadmaps provide direct input into the IT portfolio selection process to identify and set candidate 2012-2013 IT projects, as detailed in Application (Exhibit B-1), Section 6.2.5, pages 377 and expanded upon in the response to BCUC IR 1.97.1. Relevant to the 2012-2013 expenditure forecasts, the following roadmaps are referenced:

<u>Business Enablement Roadmaps:</u>

- **Transmission Technology Roadmap:** Development and update of the technology supporting operations and maintenance of Transmission assets with a 2012 and 2013 forecast expenditure of approximately $1.0 million and $500 thousand respectively;
- **Human Resources Roadmap:** Update of employee services across the Companies e.g. self-service with a 2012 and 2013 forecast expenditure of approximately $3.0 million and $1.3 million respectively;
- **Sales Technology Roadmap:** Development and update of sales functionality supporting the delivery of customer product propositions with a 2012 and 2013 forecast expenditure of approximately $1.0 million in both years;

- **GIS Roadmap:** Placement of GIS capability as a core component of enterprise information flows within the FEU with a 2012 and 2013 forecast expenditure of approximately $1.3 million and $400 thousand respectively;
- **Asset Management Planning and Prioritization Roadmap:** Support of the asset management planning processes to enable System Sustainment Planning with a 2012 and 2013 forecast expenditure of approximately $1.0 million and $100 thousand respectively; and
- **Measurement Technology Strategy:** Development and update of technology enabling gas measurement processes in the Company (i.e. meter shop production management) with a 2012 and 2013 forecast expenditure of approximately $175 thousand and $100 thousand respectively.

Technology Foundational Roadmaps:

- **IT Infrastructure Roadmap:** To upgrade existing storage technology to support ongoing business information growth with a 2012 and 2013 forecast expenditure of approximately $3.1 million and $7.1 million respectively;
- **Unified Communication Roadmap:** To upgrade telephony enabled IT services to improve customer interaction with a 2012 and 2013 forecast expenditure of approximately $530 thousand in both years; and
- **IT Risk & Security Roadmap:** To upgrade existing IT security services to improve the FEU's customer interaction with a 2012 and 2013 forecast expenditure of approximately $1.5 million and $2.0 million respectively.

98.2 Please explain the nature of the "pent-up demand from restrictions on the execution of several IT projects other than the CCE CPCN."

Response:

As identified in the response to BCUC IR 1.96.1, of the 70 projects that made up the initial 2010 IT Project Portfolio, 12 projects were deferred until after the completion of the CCE Project in early 2012. This deferral was a result of IT personnel being redirected to support the execution of the CCE Project and therefore not available for these projects. Also, due to the scope of the CCE Project, any potential project that would have impacted the SAP and supporting systems was deferred as to not impact the CCE implementation.

98.3 What capital expenditures in 2012 and 2013 are for IT projects supporting the EEC programs?

Response:

There are currently no IT Capital Expenditures forecast for 2012 or 2013 supporting the EEC programs. Any development to support these programs would be funded from the EEC Deferral Account.

99.0 Reference: Growth Capital Expenditures

Exhibit B-1, Part 6.2.3, p. 359;

1997 TGVI and TGI System Extension and Customer Connection Policies Application, BCUC 1.5.1 and BCUC 1.5.2; 2009 MX Report, p. 7

FEI and FEVI Main Extensions

99.1 Please provide copies of the latest FEI and FEVI Plant Accounting manuals and their issue dates.

Response:

A copy of the Plant Accounting manual used for the FEU is attached. The manual has been updated for the changes in the 2010-2011 RRA and reflects existing accounting policies.

99.2 Please provide the latest copies the FEI and FEVI policy and procedures manuals used by the individuals performing the main extension tests. Also provide the issue dates of the manuals.

Response:

Please refer to Attachment 99.2 for the latest standard, CUS 07-08, which outlines the main extension policy and procedures for FEI and FEVI. CUS 07-08 was issued on July 23, 2009.

CUS 07-08 is in the process of being updated to reflect updates such as name changes to the FEU and Goods and Services Tax (GST) to Harmonized Sales Tax (HST).

As noted in the FEI and FEVI 2010 Year End MX Reports submitted to the Commission on June 1, 2011, for a small percentage of main extensions (approximately 10 percent), the geo-code pricing methodology is not the most appropriate estimating method due to unique site specific requirements. In these circumstances, manual estimates are used. The following table illustrates the criteria used by the Companies to determine the requirement to use geo code versus manual estimates.

Pipeline Criteria	Geo Code	Manual Estimate
Pressure	Distribution pressure (DP)	Intermediate pressure (IP)
Material	Ployetheleyne (PE)	Steel (ST)
Diameter	Up to 60 mm (2")	88mm (3.5") and larger for PE and ST
Length	Maximum 1000m	Greater than 1000m
Cost	Maximum $100,000	Greater than $100,000
Crossing Type	Road or pipeline only	Directional drills, highway, bridge, water or railway crossing
Environmental impacts	All envirnonmental impacts except fish bearing streams	Environmental impact of fish bearing streams
Other		Vertical Sub Divisions
		Conversion Mains
		Mains in transmission right of ways

100.0 Reference: Growth Capital Expenditures

Exhibit B-1, Part 6.2.3, p. 359

2009 MX Report, p. 7

TGVI 2009 Highest Cost Mains

Name	Total Forecasted Attachments	Installed Attachments (YTD)	TECO Date	Forecasted Main Costs	Actual Main Costs	Variance
Shawnigan Lake Road	193	40	2009-06-29	$695,444	$1,917,898	($1,222,454)
West Coast Road	201	0	2009-07-28	$261,699	$401,092	($139,393)

100.1 Please update the table above to reflect the "Installed Attachments YTD" (May 31, 2011). Provide the table in fully functional electronic format.

Response:

Please refer to Attachment 100.1 for the fully functional electronic spreadsheet.

The West Coast Road project developer has installed the road, curb and street lighting but at this time there are no plans for development.

In general, consumption forecast in MX tests should materialize by the end of five years. However, as demonstrated in the West Coast Road example, there may be exceptions due to circumstances out of the control of the FEU. Inevitably there will always be uncertainty and variability inherent in forecasting housing attachments, despite the Companies' best efforts to apply their industry knowledge, experience and conservative approach to forecasting.

100.2 Given the $1.2 million negative main cost variance, should the Shawnigan Lake Road main extension be subject to a prudency review? Please explain.

Response:

No, Shawnigan Lake Road main extension should not be subject to a prudency review.

The Shawnigan Lake main extension ("MX") was necessary to provide natural gas service to customers. The MX test was based on the best information and processes in place at the time. The cost estimate for the Shawnigan Lake MX was based on the geo-code methodology, approved by Commission as part of the TGI-TGVI System Extension and Connections Review

Application (Order G-152-07), which we believed would reasonably reflect the actual cost of the MX.

As a result of reviewing the Shawnigan Lake MX and our cost estimating process, we have since recognized that for a small number of MXs, such as Shawnigan Lake, a manual cost estimating methodology is more appropriate to reflect site specific requirements which are not appropriately reflected in geo-code. We have implemented process improvements which will apply to a small number of main extensions, in order to reduce the variance between the actual and estimated cost.

100.3 Please provide the authority level required for the approval of the Shawnigan Lake Road and West Coast Road main extensions.

Response:

Please refer to BCUC IR 1.100.4, Attachment 100.4, which contains the MX standard CUS 07-08 dated January 12, 2006, the authority level required for the approval of the two projects was as follows:

- Shawnigan Lake requires the approval of the President of the gas segment
- West Coast Road requires the approval of the VP, Distribution

The relevant approvals were obtained on both these projects.

Shawnigan Lake and West Coast Road represent only 2 out of 1,179 main extension projects over the past three years, equating to 0.17 percent of the total population. In general, the cost estimating process followed by the Companies continues to be appropriate whereby geo code pricing is used for forecasting main extension costs for the majority of the population. Following the Shawnigan Lake project, the Companies have made improvements by implementing a manual cost estimating process for a small number of main extensions to ensure that the forecast costs for these main extensions are as accurate as possible.

100.4 Please provide a copy of the FEVI policy and procedures manual that was used when the Shawnigan Lake Road and West Coast Road main extension tests were performed. Also provide the issue dates of the manuals.

Response:

Attachment 100.4 contains the relevant MX standard CUS 07-08, which was in use at that time, issued January 12, 2006.

101.0 Reference: Growth Capital Expenditures

Exhibit B-1, Application, Part 6.2.3, p. 359

1997 TGVI and TGI System Extension and Customer Connection Policies Decision (MX Test Decision), p. 37

FEI and FEVI Growth Capital

"Proposed main extension projects are evaluated through a main extension economic test ("MX Test") which analyzes cost estimates for installing the main, projections in numbers of customers attached as well as forecast customer gas usage. Uneconomic results require contributions from customers in order for the planned extensions to proceed." (Exhibit B-1, p. 359)

"The Commission Panel directs the Companies to file with the Commission on an annual basis, within 90 days of calendar year end, a Main Extension Report…" (MX Test Decision, p. 37)

101.1 Please explain why the FEI and FEVI have not filed the 2010 Main Extension Report in accordance with MX Test Decision.

Response:

The Companies filed the 2010 MX Report with the Commission on June 1, 2011. The reason for the delay in filing is the outcome of a process agreed to between the Companies and Commission Staff.

The Companies and Commission Staff had engaged in dialogue with respect to the 2010 MX Report via written correspondence, phone calls and a meeting on February 15, 2011 to review the compliance reporting requirements. At the meeting on February 15, 2011, it was agreed between Commission Staff and the Companies that they would provide a draft report on March 31, 2011 to Commission Staff for discussion and meet with Commission Staff on April 12, 2011 to present the findings contained within the draft report. Following the April 12, 2011 meeting and presentation, Commission Staff provided comments on the draft report on April 20, 2011.

This timeline was adopted and implemented as agreed by the parties and as an outcome, pursuant to Commission Order Nos. G-152-07 and G-6-08, the Companies submitted the 2010 FEI and FEVI Year End Main Extension and FEI Vertical Subdivision report on June 1, 2011.

101.2 When do FEI and FEVI expect to file the 2010 Main Extension Report? When available, please file a copy of this report as an exhibit to this proceeding.

Response:

The 2010 Main Extension Report was filed with the BCUC on June 1, 2011. Please see Attachment 101.2 for a copy of the report.

101.3 Please complete the table below the forecast cost, actual cost, variance (forecast cost-actual cost), the percentage variance (variance/forecast cost) and the number of new mains, new services and new meters installed for each of the Companies. Also provide the tables in fully functional electronic format.

FEI New Customer Mains

	2006	2007	2008	2009	2010	Year to date 2011
Forecast cost						
Actual cost						
Variance						
% Variance						
#of Mains						

Response:

Please refer to Attachment 101.3 for the fully functional electronic spreadsheet.

Forecast cost data from 2006 and 2007 is not readily available. As discussed in the response to BCUC IR 1.34.1, the forecast cost data derived from CAFE is readily available from 2008 onwards.

102.0 Reference: Growth Capital Expenditures

Exhibit B-1, Part 6.2.3, p. 359

MX Test Decision, p. 36 and 2009 Year End TGI-TGVI Main Extension & TGI Vertical Subdivision Reports (2009 MX Report), p. 11

FEI and FEVI Main Extensions

"The Commission Panel finds such a proposal to be in the public interest and to conform with its Guidelines and approves the proposal to establish a new threshold PI [Profitability Index] of 0.80 for individual main extensions, and to establish an aggregate PI of 1.10 as the threshold for all main extensions completed on an annual basis." (MX Decision, p. 36)

"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.

2008 Installed Mains

Company	Average Forecast PI	Average Actual PI	PI w/Year 1 Actuals Incl.
TGI	1.3	1.2	0.8
TGVI	1.6	1.4	0.6

(2009 MX Report, p. 11)

102.1 Using the format of the table below, for FEI and FEVI, list each 2008 main extension with a PI < 0.8 with Year 1 Actuals Included. Also provide the tables in fully functional electronic format.

FEI 2008 Main Extensions PI < 0.8 with Year I Actuals Included

Name	Location	Actual Length (m)	Total Forecasted Attachments	Installed Attachments (YTD)	Forecasted Main Costs	Actual Main Costs	Variance (Forecast-Actuals)	Forecast PI	PI w/Year 1 Actuals Incl.

Response:

There are no forecast main extensions with a Profitability Index ("PI") < 0.8.

If any MX test results in 2008 indicated a forecast 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 ("CIAC") by customers to be served by the MX. In 2008, there were 47 customers that provided a CIAC, 24 from FEI and 23 from FEVI.

As discussed in the FEI and FEVI 2010 Year End MX and Vertical Subdivision Reports submitted to the Commission June 1, 2011, actual individual and aggregate main extension PI values using actual consumption and cost data will be provided for information purposes at the end of the five-year period (i.e. following October 31, 2013 for 2008 mains). 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. The Companies believe that there is limited value in reporting on a re-forecast PI value based on re-forecasting consumption for every main extension annually and then re-running the MX Tests. There are two main reasons for this:

- 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 re-running 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.
- Second, the accuracy of any potential, revised attachment and consumption forecasts would still be variable as they would be subject to the cyclical BC housing market conditions which are out of the Companies' control and difficult to predict into the future.

Consequently, re-forecasting load annually and re-running MX Tests would provide limited added value to the Commission's MX Test review while adding substantively to the Companies' administrative workload, resulting in additional costs for customers. The Companies believe that in taking this approach to reporting PI values they are in full compliance with the directives set forth in Orders No. G-152-07 and G-6-08.

102.2 Mains installed in 2008 will have 5 full years of consumption history in 2013. If a 2008 main has a PI <0.8, should the capital cost associated be removed from rate base in order to achieve a PI of 0.8?

Response:

No, the capital cost from a main extension installed in 2008 that may hypothetically have a PI of less than 0.8 in 2013 should not be removed from rate base.

In the Commission's Decision and 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 2008 main extension hypothetically has a PI value less than 0.8 in 2013, it is the aggregate threshold that demonstrates whether the existing customers received a benefit from the attachment of new customers in 2008 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 is 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. In 2008, FEI and FEVI met the approved MX objectives by following the process that if any 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. In addition, on a portfolio basis, the PI in 2008 for FEI and FEVI was 1.3

and 1.6, respectively, greater than the 1.1 threshold. The 2008 MX tests were based on the best information and processes in place at the time.

102.3 Do you agree that a main extension should have reached its potential attachments by 5 years following installation? If not, why not?

Response:

In general, consumption forecasts in MX tests should materialize by the end of five years. However, there may be exceptions due to the fact that the BC housing market and the FEI and FEVI consumption results are closely related and, both have been highly cyclical in the recent past. There will always be uncertainty and variability inherent in forecasting housing attachments, despite the best efforts by FEI and FEVI to apply their industry knowledge, experience and conservative approach to forecasting.

102.4 Is FEU willing to tests main extensions after 5 full years of service to determine of actual usage is consistent with original consumption estimates? How might this test be done?

Response:

As elaborated in the FEI-FEVI 2010 Year End Main Extension and 2010 FEI Vertical Subdivision Report submitted on June 1, 2011, the FEU believe that the appropriate time frame to provide the actual main extension's PI using actual consumption data is at the end of the five-year period. For example, for 2010 main extensions this would occur in 2015, and for 2008 and 2009 main extensions, actual PI would be provided in 2013 and 2014, respectively. This test would be completed by re-running the MX test with the actual consumption data at the end of the five-year period to calculate a final PI value and would be reported within the Year End Main Extension compliance report for information purposes only. In general, consumption forecast in MX tests should materialize by the end of five years; however, there may be exceptions due to circumstances out of the control of the FEU.

The Companies already provide the Commission with an annual MX report that provides updates on consumption. In the 2010 MX Report for example, the Companies made consumption reporting improvements by segmenting actual versus forecast consumption in terms of attachments, consumption in gigajoules ("GJ") and GJ per attachment. Consumption is further segmented by the forecast total over years 1- 5, the forecast up to the current year and the actual year-to-date results. Inevitability, there will always be uncertainty and variability inherent in forecasting consumption, despite the Companies' best efforts, including the application of industry knowledge, experience and a conservative approach to forecasting.

103.0 Reference: Natural Gas Vehicles

Exhibit B-1, Application, Section 1.2.3.2, pp. 13-14; Section 6.2.3.5, p. 365

Approval of NGV Fueling Assets for 2012 and 2013

On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval. Given customer support[11] for the NGV Application and our belief that this is part of our core business, we have included in this RRA our project costs and revenue to undertake this business for 2012 and 2013. Thus these impacts have been integrated into our other revenue forecasts (Section 5.5), O&M (Section 5.3), capital expenditures (Section 6.2) and rate base deferral (Section 6.3) for the 2011 CNG and LNG Service Costs and Recoveries.

NGV

Capital invested in NGV fueling assets, subject to approval of the NGV Application presently before the Commission, is forecast to be $4 million in 2012 and $4.8 million in 2013. These projects will be accompanied by contracts that provide for their forecast incremental costs of service to be recovered through dedicated take-or-pay incremental revenues from the incremental NGV fueling customers. Further detail on this capital investment is provided in Appendix I.

103.1 The reference to $4M in 2012 and $4.8M in 2013 of NGV fueling assets is not specifically identified in Section 8 on Approvals Sought and Proposed Regulatory Process. Please confirm that the FEU is seeking approval for the fueling assets in this RRA for 2012 and 2013.

Response:

The forecasted NGV fuelling assets of $4M in 2012 and $4.8M in 2013 form part of the growth capital expenditures, which will become part of the rate base of FEI. Thus, FEI's revenue requirements for 2012 and 2013 are reflective of these forecast capital expenditures.

FEI is not specifically seeking the Commission's acceptance pursuant to section 44.2 of the *UCA* of the capital expenditures for the NGV fueling assets. Nor is it required to do so under the *UCA*. Please also refer to the response to BCUC IR 1.129.1.

104.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.1, pp. 392-396

Energy Efficiency and Conservation (EEC) Allocations – Modified Deferral Account

"In this Application the Companies are seeking the following approvals related to EEC: The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler."

Table 6.3-6 indicates the percentage of actual spend was 88% Mainland and 12% Vancouver Island in 2010, and is projected to be 78% Mainland and 22% Vancouver Island in 2011. In 2012 and 2013 the EEC programs will be available to customers in Whistler in addition to Industrial customers of FEVI.

"The additions to the non-rate base account will be tracked on a Company basis for Mainland, Vancouver Island and Whistler." [Ref: p. 395]

104.1 Please explain why the deferral account additions should be allocated on an average customer basis when Vancouver Island has a higher percentage uptake, which will likely be even higher as industrial customers become eligible.

Response:

Please refer to the response to BCUC IR 1.104.2.

104.2 Please explain why the rate base deferral account and the proposed non-rate base deferral account would be tracked/allocated on different methodologies.

Response:

The FEU believe that it is appropriate to have two tracking/allocation methodologies that reflect the nature of the two general types of EEC costs: non-incentive costs and incentive costs. All non-utility-specific non-incentive costs will be allocated amongst the utilities based on average number of customers and all incentive costs will be tracked by utility and based on actual customer participation, regardless of the type of EEC deferral account used (i.e. rate base or non-rate base).

The FEU have proposed this modification to the deferral account mechanism to address the need to expand EEC to all the FEU's customers and to account for possible variations from forecast in customer participation levels that may occur in the two-year test period.

The two general types of EEC costs are discussed further below:

I. Non-Incentive Costs

Non-incentive costs form the basis for program delivery and include costs like labour, education, and general program administration or overhead and many are common costs that are carried out by the one group of EEC staff for the benefit of customers in all service territories. These non-incentive costs are therefore similar to shared services costs that are typically allocated among utilities or business divisions in the same corporate family based on one or more cost drivers; therefore, the FEU believe that the number of customers is an appropriate allocation methodology for non-utility-specific non-incentive costs. This allocation is consistent with the treatment of other costs in the FEU, like Core Market Administration Expense ("CMAE"), that are incurred for the benefit of all customers (or all customers in the relevant categories). As appropriate, some utility-specific non-incentive costs may be tracked and allocated to each utility.

The rate base deferral account addition of $20 million in each forecast year has been set to generally represent the forecast of non-incentive costs. To the extent that non-utility-specific non-incentive costs exceed $20 million in 2012 or 2013, and as such are accounted for in the non-rate base deferral account, the FEU will allocate those non-incentive costs to each utility based on average customers. In the event that non-incentive costs are less than $20 million in 2012 or 2013, the FEU will include actual incentive costs as part of the rate base addition for each year, as they apply to each utility, until the forecast annual addition of $17.8 million in FEI, $2.0 million in FEVI and $0.2 million in FEW is achieved.

II. Incentive Costs

Incentive costs, on the other hand, can be attributed to each utility based on actual customer participation in the programs. Incentive costs are specific to each EEC program and are fully dependent on customer participation; therefore, the FEU believe that it is appropriate to track incentive costs by utility and based on actual customer participation. For example, as more industrial customers become eligible on Vancouver Island and have a higher percentage participation in EEC programs, the increase in participation will be reflected in the incentive costs allocated to Vancouver Island. For additional clarity, the following table compares the existing EEC deferral mechanism with the mechanism as proposed in this Application:

	Existing	Proposed
Funding Envelope		
General Principles	• Maximum funding level by year • Account managed using a portfolio approach (i.e. EEC funding approved on a total basis, not program basis) • All spending subject to TRC on a overall portfolio level rand Principles of EEC • Innovative Technology program area must have a TRC ratio of greater than 1	• Maximum funding level by year • Account managed using a portfolio approach (i.e. EEC funding approved on a total basis, not program basis) • All spending subject to SCT on a overall portfolio level and Principles of EEC • Innovative Technology program area must have SCT ratio of greater than 1
Funding Allocation to Rate Base	• Individual forecast per year for FEI and FEVI • Total forecast funding envelope per Utility is included as rate base addition	• FEU forecast of $20 million per year • $20.0 million rate base addition allocated amongst Utilities based on average customers
Funding Allocation to Non-Rate Base	N/A	• FEI is seeking acceptance of an expenditure schedule of $54.5 million for each of 2012 and 2013 to be spent in the service territories of the Utilities • FEI will record the actual as-spent amount (i.e. no forecast additions to this account) in a non-rate base deferral account and the additions to the non-rate base account will be tracked on a utility basis for Mainland, Vancouver Island, Whistler and Fort Nelson • Maximum addition to this account for FEU in total for each year of $54.5 million = total funding envelope of $74.5 million less the $20.0 million rate base addition • Actual spending captured and allocated on a Utility basis
Opening Balance of Deferral Account		
Rate Base	Trued up to reflect actual additions from prior periods	Trued up to reflect actual additions from prior period
Non-Rate Base	N/A	Forecast additions are not included in rates; therefore, opening balance for the next RRA will reflect actual additions plus AFUDC recorded against the actual additions

	Existing	Proposed
Additions to Deferral Account (s)		
Rate Base	Forecast basis: individual EEC forecast for FEI and FEVI, which combines non-incentive and incentive costs Actual basis: individual EEC actual additions for FEI and FEVI, combined non-incentive and incentive costs	Forecast: $20.0 million allocated to each Utility based on average number of customers (Table 6.3-7, Page 395) Actual: If non-incentive costs are < $20.0 million; FEU will include actual incentive costs in the rate base addition for each year, as they apply to each Utility, until the forecast annual addition of $17.8 million in FEI, $2.0 million in FEVI and $0.2 million in FEW is achieved.
Non- Rate Base	N/A	Forecast: No additions Actual: Captured on an as spent basis, maximum addition to this account for FEU in total for each year is $54.5 million = total funding envelope of $74.5 million less the $20.0 million rate base addition and is captured on a utility basis
Amortization of Deferral Account(s)		
Rate Base	• Ten year amortization period, beginning in the year following the addition • Amortization expense reflects actual additions from prior periods and forecast additions for forecast period (i.e. in a two year forecast period, amortization expense in year two will reflect the forecast additions in year one) • Amortization expense is not trued up in the forecast period; however, in each RRA the amortization expense is recalculated to reflect actual additions so that only actual additions to the account are recovered from customers	• Ten year amortization period, beginning in the year following the addition • Amortization expense reflects actual additions from prior periods and forecast 2012 additions of $17.8 million for FEI, $2.0 million for FEVI and $0.2 million for FEW for forecast period (i.e. in a two year forecast period, amortization expense in year two will reflect the forecast additions in year one) • As noted in rate base additions, the account will be managed such that it is unlikely that rate base additions will vary from $20.0 million; therefore, in all likelihood forecast and actual amortization expense will closely match
Non- Rate Base	N/A	• Ten year amortization period, beginning in 2014 (i.e. there will be a one year lag on the amortization of 2012 additions) • Amortization of the account will be determined in the next RRA o Options for recovery of amortization may include transferring the closing 2013 balance in the non-rate base account to the rate base account effective January 1, 2014 or recovering the balance in the non-rate base account through a delivery rate rider

105.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.1, pp. 392-396

EEC Forecast included in Rate Base – Modified Deferral Account

105.1 Please explain why it doesn't make as much sense to forecast the amount to be included in rates based on the actual of $12.6 for 2010?

Response:

The actual EEC spending of $12.6 million in 2010 is too low to form a reasonable basis for the amount to be included in rates in 2012 and 2013.

The FEU have been in the process of ramping up EEC activities and spending since BCUC approval of the Companies' 2008 EEC Application on April 16, 2009. 2010 was the first full fiscal year of this ramping up process and expanding EEC programs and activities to the full approved level of spending proved to be more challenging and to take longer than anticipated. The length of time to ramp up EEC programs and activities was affected by the timing of the Commission EEC decision, the time required to hire and train staff and the time required to develop and implement the initial portfolio of programs. The experience gained by the FEU in the two years since the EEC decision was issued provides a strong foundation for continued growth going forward.

Ramping up EEC programs and activities and the associated spending has continued such that the FEU expect $19.8 million in projected EEC spending in 2011 (please refer to BCUC IR 1.3.3). The FEU plan to continue increasing the level of EEC spending in 2012 and 2013 as indicated by the request for approval of $74.5 million per year overall of EEC spending, including $38 million per year for Conventional EEC Activity, $11.5 million per year for Innovative Technologies (including NGV) and $25 million per year for New Initiatives.

Past practice has been to include the full forecast level of EEC spending and the related cost of service impacts in the revenue requirements. In this Application the FEU have recognized that since EEC programs and spending are still on a fairly steep growth curve there may be concerns about under-spending and recovering more in rates that would be warranted by actual spending levels. Also the FEU have noted that the proposed New Initiatives spending of $25 million per year is contingent on changes being approved to the EEC benefit/cost screening test and/or changes to the provincial DSM Regulation. The proposed approach of having $20 million per year of EEC spending (and the related cost of service impact) in the 2012 and 2013 rates and recording spending over the $20 million per year level in a non-rate base deferral account (attracting AFUDC) addresses the variation in customer participation that may occur in any given year while keeping the Company whole for the return on investment that it would receive if that actual level of EEC spending had been included in rates.

106.0 Reference: Energy Policy Deferral Accounts

Exhibit B-1, Part 6.3.2, p. 392

Enhanced Energy Efficiency and Conservation Programs

106.1 FEU forecasts the balance in the EEC deferral account to increase from $29,793K in 2012 to $41,173K in 2013. Please explain FEU's plan for recovery of the balance of this deferral account.

Response:

Pursuant to Commission Order No. G-36-09, the FEU amortize annual EEC rate base deferral account additions through rates over a ten-year period. That is, the FEU include amortization expense related to the EEC account in the cost of service of each of the utilities which is recovered through rates.

Therefore, the 2012 closing balance of $35.872 million ($29.793 million is the mid-year balance) will be recovered over the ten-year period ending 2022 and the 2013 closing balance of $46.476 million ($41.173 million is the mid-year balance) will be recovered over the ten-year period ending 2023.

The following table shows the continuity for the recovery of the 2012 and 2013 EEC rate base deferral account additions of $20.0 million in each year.

FEU Rate Base Deferral Account
Amortization of 2012 and 2013 EEC Additions
$ Thousands

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Opening Balance	-	15,000	28,500	25,500	22,500	19,500	16,500	13,500	10,500	7,500	4,500	1,500
Gross Additions	20,000	20,000	-	-	-	-	-	-	-	-	-	-
Tax	(5,000)	(5,000)	-	-	-	-	-	-	-	-	-	-
Net Additions	15,000	15,000	-	-	-	-	-	-	-	-	-	-
Amortization Expense	-	(1,500)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(1,500)
Closing Balance	15,000	28,500	25,500	22,500	19,500	16,500	13,500	10,500	7,500	4,500	1,500	-

107.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.1, pp. 392-396

EEC Incentive Non-rate base Deferral Account – New Deferral Account

107.1 Please explain the use of the word "Incentive" in the title for this deferral account. Is there an incentive for FEU to have a non-rate base deferral account attracting AFUDC compared to a rate base deferral account?

<u>Response:</u>

No, there is no incentive for the FEU to have a non-rate base deferral account attracting AFUDC compared to a rate base deferral account. The FEU have proposed the use of the non-rate base EEC deferral account to address the variation of customer participation in EEC programs that may occur.

Please refer to the response to BCUC IR 1.104.2.

The use of the word "Incentive" in the non-rate base EEC deferral account name is in reference to the type of EEC costs that are expected to make up the majority of the balance in the account.

108.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.3, pp. 396-397

Compliance with Emissions Regulations – New Deferral Account

"The growing number of regulations around emissions trading may result in incremental compliance costs and recoveries during the forecast period. These compliance costs and recoveries are difficult to forecast because of uncertainty around the final form and applicability of emissions trading regulations. We request a deferral account to capture both compliance costs, and revenues collected associated with these regulations. For purposes of the 2012 and 2013 revenue requirement, additions to this account have not been forecast and the amortization of any balance that accumulates in this account will be addressed in a future revenue requirement application."

"There are financial impacts associated with complying with cap-and-trade regulation, including purchasing allowances and offsets, or making internal reductions to meet targets. The Utilities have processes and controls in place for capturing, measuring, and reporting GHG emissions and have worked towards a carbon management strategy, including steps to reduce operating emissions, which will help achieve compliance with the potential cap-and-trade regulation."

108.1 Please explain the tracking/recording process to be used to gather all Emission Regulation compliance related costs and revenues.

Response:

The process to track and record all costs and revenues related to Emissions Regulation will follow the Companies' existing accounting policies for recording and tracking costs and revenues in the appropriate cost centre or deferral account when incurred.

The Environment, Health & Safety (EH&S) group will be responsible for and looking after the Compliance with Emissions Regulations deferral account. Once new regulations come into effect and we have more clarity as to how we are required to comply with such regulations, we can finalize our strategy, decide how the program will be defined, and create the necessary internal orders and accounts to capture the costs.

108.2 Please explain if/how the existing embedded costs with respect to GHG will be included in this new deferral account.

Response:

The FEU have requested a deferral account to capture all costs and revenues related to compliance with Emissions Regulations, as there is still a high degree of uncertainty associated with these regulations. As Cap and Trade is yet to be legislated, the requested deferral account will capture costs and/or revenues going forward to comply with the regulations when they come into effect. As stated in the Application (Exhibit B-1), the cap-and-trade regulations may apply to our operating emissions, requiring us to comply with the requirements by purchasing allowances and offsets, or making internal reductions to meet targets. Such compliance costs will be charged to the Compliance with Emissions Regulations Deferral Account.

The costs related to existing and known regulations, including the GHG Reporting Regulation, are embedded in the O&M expenditures forecast in this RRA and these costs will not be charged to the deferral account.

109.0 Reference: Rate Base

Exhibit B-1, Application, Section 6.3.1.6, p. 391

Vancouver Island Gas Cost Variance Account (GCVA)

In the Application, FEVI is proposing to discontinue the quarterly reporting of the Vancouver Island forecast gas costs and GCVA balances.

109.1 If the quarterly reporting requirements are discontinued, would FEVI consider it appropriate to require annual reporting of the forecast gas costs and GCVA balances?

Response:

Based on the FEVI proposal for customer rates to remain frozen for the duration of the 2012-2013 RRA period, FEVI is of the view that quarterly reporting of the forecast gas costs and GCVA is no longer necessary. As established through the FEVI 2010-2011 Revenue Requirements and Rate Design Negotiated Settlement (approved under Commission Order No. G-140-09) and as proposed in this Application, FEVI core market rates remain frozen and are not subject to quarterly gas cost flow through adjustments.

FEVI is not averse to providing annual reporting of the forecast gas costs and GCVA balances but notes that FEVI will still file its required annual gas cost status report by April 30 of each year wherein the variances between the forecast and recorded gas cost and gas cost recoveries for the calendar year just ended are reported.

Should the Commission also require a report on an annual basis of the forecast gas costs and GCVA balance for the duration of the period during which FEVI core market rates remain frozen, FEVI proposes that report be filed with the Commission at the time the fourth quarter gas cost reports for the other FEU entities and service areas are submitted.

109.2 If the quarterly reporting requirement is discontinued, please comment on the administrative impact of requiring FEVI to report on the forecast gas costs and GCVA balances should the GCVA exceed certain predetermined tolerances?

Response:

Pursuant to Commission Order No. G-2-03, dated January 14, 2003, the Commission approved a Negotiated Settlement on the 2003-2005 Forecast Revenue Requirements for FEVI (formerly known as Terasen Gas (Vancouver Island) Inc., and prior to that called Centra Gas British Columbia Inc.). The establishment of the GCVA was approved effective January 1, 2003, and FEVI was to provide the Commission and Registered Interveners with quarterly reports on the gas costs and GCVA balances to be used for determining future customer rates. Further, Commission Order No. G-42-03, dated June 5, 2003, approved the FEVI (then called Centra Gas British Columbia Inc.) September 2002 Rate Design Application, and accepted the soft-cap rate setting mechanism under which the FEVI natural gas rates for core market customers would be set to be competitive with efficiency adjusted electricity rates and fuel oil prices. FEVI core market rates would fluctuate as necessary to respond to changing market conditions and would allow FEVI to maximize its revenue from core market customers in order to recover the accumulated revenue deficiency over the shortest time period reasonably possible. The competitive energy information was also included as part of the FEVI quarterly gas cost reports.

As established through the FEVI 2010-2011 Revenue Requirements and Rate Design Negotiated Settlement (approved under Commission Order No. G-140-09), and as proposed in the FEU 2012-2013 RRA, FEVI core market rates remain frozen and are not subject to quarterly gas cost flow through adjustments.

The gas cost revenue-to-cost ratio rate change mechanism as established under the Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (the "Guidelines") issued as Appendix I to Commission Letter No. L-5-01, including the Commission approved revisions to the Guidelines pursuant to Commission Letter No. L-40-11 (notably that the commodity rate change trigger mechanism will be the ± 5 percent trigger ratio plus a minimum rate change threshold of ± $0.50/GJ) were developed in regards to the FEI gas cost mechanisms. Although the Commission anticipated the Guidelines would also generally apply for other natural gas and propane utilities, FEVI is of the view that during the remainder of the period that its core market rates are frozen the Guidelines are not appropriate for the review of its gas cost recoveries. FEVI believes the GCVA balance needs to be reviewed in conjunction with the RSDA, and that quarterly reporting and review are not required. As discussed in the response to BCUC IR 1.109.1, FEVI is not opposed to reporting the GCVA and RSDA forecast balances on an annual basis and suggests such reporting be completed at the time 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.

109.3 Please provide the cost saving for FEVI to discontinue the quarterly reporting of the Vancouver Island forecast gas costs and GCVA balances for 2012.

Response:

There will be no cost savings related to the proposed discontinuation of the quarterly gas cost reports for FEVI.

The proposal to discontinue submitting the FEVI quarterly reports on the GCVA and RSDA provides only minor administrative and regulatory efficiencies.

110.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.4, pp. 397-398

2010-2011 Biomethane Program Costs – Modified Deferral Account

"In accordance with Commission Order No. G-194-10, FEI has created a non-rate base deferral account attracting AFUDC to capture the biomethane costs applicable to all customers incurred prior to January 1, 2012. Commencing January 1, 2012, this account is transferred to rate base and is amortized through delivery rates over a three year period." [Ref: pp. 397-98]

"In addition to the BVA, the Commission also approved two additional new non-rate base deferral accounts ("New Deferral Accounts") to capture costs, as described in the Application, incurred prior to January 1, 2012: i) Costs of service associated with the capital additions to the delivery system; and ii) Operating and maintenance costs applicable to all customers (attracting AFUDC)." [Ref: B-1, Appendix J, p. 1]

110.1 Please confirm the Company has created only one non-rate base deferral account and not the two approved in Commission Order G-194-10 and referenced in Appendix J to the Application.

Response:

As per the Commission Decision and Order No. G-194-10, dated December 14, 2010, FEI has created three deferral accounts:

1. **The Biomethane Variance Account ("BVA"):** the BVA is being recorded as a non-rate base deferral and the accounting treatment is discussed and described in BCUC IRs 1.185.1 and 1.185.2;

2. **Biomethane Program Costs - Capital:** this account captures the cost of service, except for O&M, applicable to all customers in 2010 and 2011 associated with the capital additions to the delivery system; and

3. **Biomethane Program Costs - O&M:** this account captures the operating and maintenance costs incurred in 2010 and 2011 applicable to all customers (attracting AFUDC).

Although tracked separately, the two program cost deferral accounts were combined into one account for presentation purposes.

Commencing January 1, 2012, both of the program cost accounts are transferred to rate base and amortized through delivery rates over a three-year period.

110.2 Please confirm the "Interconnect facilities" O&M costs projected at $49,500 shown in Table J-2 of Appendix J are the "Costs of service associated with the capital additions to the delivery system." If this assumption is not correct, please explain what the correct assumption is.

Response:

The assumption as stated in the question is incorrect. The O&M cost of the interconnect facilities is only one of the cost of service components associated with the capital additions to the delivery system. The other cost of service components, which include the depreciation provision, earned return and income tax expense, must be added to the O&M cost to derive the total costs of service associated with the capital additions to the delivery system.

Please refer to Table J-5 of Appendix J of the Application (Exhibit B-1) which provides the total cumulative cost of service associated with the program O&M costs and the capital additions to the delivery system of $706,100 ($616 thousand for the O&M Program plus $90.1 thousand for depreciation, income tax and earned return) for 2010 and 2011. The capital related component of the total cost of service would be $140 thousand ($49.5 thousand O&M plus $90.1 thousand for capital depreciation, earned return and income tax).

110.3 Please explain why this non-rate base account is transferred to rate base while being amortized.

Response:

The program costs incurred prior to January 1, 2012 are to be recorded in a non-rate base deferral account, this is in accordance with FEI's proposed treatment in the Biomethane Application and was approved by the Commission in Order No. G-194-10. In the Biomethane Application, (Exhibit B-1) Section 10.5 (Page 111) FEI stated:

> *"The Company believes the use of a deferral account is appropriate for the remaining duration of the revenue requirements period (2010 / 2011) but that the future costs should be included in the utility's rate base and cost of service effective January 1, 2012*

as the safe operation of the distribution system provides benefits to all Terasen Gas (FEI) customers".

Deferral account treatment of the program costs incurred in 2010 and 2011 was required because the Biomethane Application was filed subsequent to the determination of delivery rates for 2010 and 2011. The delivery rates in place for 2010 and 2011 were set in accordance with BCUC Order No. G-141-09. Therefore, the requested and approved deferral account mechanism was the most appropriate method to capture the costs incurred in 2010 and 2011 for future recovery from customers

The non-rate base accounting of the program costs, as applied for, was only approved until the end of 2011. The non-rate base program cost deferral accounts begin amortizing once transferred to rate base. That is, amortization of the account does not occur before the account is transferred to rate base on January 1, 2012.

110.4 Please explain where the "Biomethane Program Costs - Other Revenue" shown in Table J-5 of Appendix J can be referenced in the deferral accounts.

Response:

The Biomethane Program Costs – Other Revenue of $90,100 is embedded in the 2010 – 2011 Biomethane Program Costs of $897 thousand (Application, Exhibit B-1, Section 7, Tab 7.1, Schedule 68, Line 13, Column 3). The other items embedded in the $897 thousand are cumulative 2010 and 2011 O&M of $616 thousand (net-of-tax), as provided in the Application, Appendix J, Table J-5, and Biomethane Application costs of $191 thousand (net-of-tax).

111.0 Reference: Rate Base

Exhibit B-1, Part 6.3.2.5, p. 398

2011 CNG and LNG Service Costs and Recoveries – New Deferral Account

"In the recent CNG and LNG Service Application, FEI requested approval for a non-rate base deferral account attracting AFUDC to capture the O&M costs and cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. FEI has captured the forecast costs and revenues associated with the Waste Management Fueling Station agreement, as well as two additional fueling station agreements which are anticipated to be in-service in 2011, in this non-rate base deferral account, and has transferred the projected balance to rate base January 1, 2012 with three year amortization. Any variances between the forecast level of 2011 expenditures and revenues and actual expenditure and revenue levels will be amortized in rates beginning in 2014. CNG and LNG Service costs and recoveries incurred after December 31, 2011 are embedded in this Application and used in the determination of the revenue requirements for 2012 and 2013. The forecasts made in relation NGV refueling infrastructure in the 2012-2013 RRA are premised on the assumption that the CNG and LNG Service Application will be approved as filed. Further, it is also based on the premise that the EEC incentives for natural gas for Transportation will continue. If necessary, FEI will file an evidentiary update to this application to take into account the Commission's Decision on the CNG and LNG Service Application once it is available."

Commission Order G-6-11 approved the Waste Management Fueling Station Agreement.

"On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval." [Ref: B-1, Part 1, p. 14]

111.1 Please provide an update on the two additional refueling contracts referenced above, including the expectation for meeting the dates and amounts embedded in this Application.

Response:

The two additional refueling contracts referenced in the question are a CNG fueling station agreement with Kelowna School District ("KSD") and an LNG fueling station agreement with Vedder Transport ("Vedder").

In July, 2011 FEI will submit its application for approval of a Service Agreement for Liquefied Natural Gas ("LNG") Service, for approval of a Service Agreement for LNG Delivery, for approval of a Daily Charge for the use of an LNG Tanker and for approval of a Daily Charge for the use of a Mobile LNG Refueling Station.

Under the terms of the LNG Service Agreement, Vedder has committed to consume 57,500 GJ over the term of the temporary fueling service period. Vedder expects to begin fueling service in August of 2011. The original in-service date was June 2011.

At the time of this filing, FEI was engaged in negotiations with KSD to execute a CNG Service Agreement. The project remains on track to achieve its target in-service date of September 2011. While annual volume estimates are unchanged, the monthly 'take-or-pay' volume has not yet been negotiated between the parties.

111.2 Please confirm the actual costs and recoveries for the Waste Management Fueling Station Agreement are being kept separately for future disposition as required under Commission Order G-6-11.

Response:

The actual costs and recoveries for Waste Management have been tracked through the use of an internal order number in accordance with directive three of Commission Order No. G-6-11 and as discussed on Page 4 of Appendix A to Order No. G-6-11, Reasons for Decision:

> "*Teasen shall keep costs and revenues related to the WM Agreement segregated and kept sufficiently distinct so as to be severable, in the event that the Commission Panel determines that final approval of the WM Agreement is not warranted."*

In this Application, based on the premise that the CNG and LNG Service Application will be approved as filed, FEI has included the forecast and actual costs and recoveries associated with Waste Management in the 2011 CNG and LNG Service Costs and Recoveries deferral account. FEI has amortized the forecast deferral account balance through delivery rates over a three year period commencing 2012.

112.0 Reference: Rate Base

Exhibit B-1, Application, Section 6.3.2.6, p. 399

CNG and LNG Service Costs and Recoveries

"The NGV Application contemplates a model for FEI to own and operate refueling stations for natural gas vehicle customers in a manner which ensures that all FEI customers benefit from the increased system throughput resulting from NGV volumes, while ensuring that the forecast incremental costs of FEI owning and operating these stations are recovered through a contract rate charged to these incremental customers." [Ref: B-1, Part 1, p. 13]

"On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval." [Ref: B-1, Part 1, p. 14]

"In its recent CNG and LNG Service Application dated December 1, 2010, FEI requested approval for an ongoing rate base deferral account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand.

In this Application, FEI is seeking approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16 of $2.9 million in 2012 and $4.4 million in 2013.

FEI believes that a deferral account is appropriate because Rate Schedule 16 is a relatively new rate schedule and at the time of this filing we have no customers using this service. It is expected that Vedder Transportation will be the first customers to use this Rate Schedule beginning in the second half of 2011. While FEI believes its CNG and LNG forecasts to be reasonable, FEI believes that both the customer and the shareholder should be kept whole with respect to Rate Schedule 16 and fuelling station recoveries for CNG and LNG Service and that a deferral account mechanism is appropriate, at least for the 2012 and 2013 forecast period. Additions to this account over the forecast period will be recovered from or refunded to all non-bypass customers beginning in 2014."

112.1 Please confirm that the revenue forecast variations that FEI wishes to capture in this deferral account include revenue variations on the forecast LNG fueling station revenue as well as the forecast Rate Schedule 16 delivery margin revenue.

Response:

Confirmed.

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.[17]

The revenue will be comprised of the fueling station revenue as well as the revenue collected under the Rate Schedule 16 tariff. The Rate Schedule 16 tariff is comprised of the following:

1. A variable charge with a monthly take-or-pay volume for the liquefaction, storage, transportation and dispensing of LNG; and
2. A cost of gas or commodity charge based on the Sumas monthly Index Price.

112.2 Please confirm that the revenue forecast variations that FEI wishes to capture in this deferral account include revenue variations on the total forecast LNG fueling station revenues rather than just the revenues in excess of the maximum contract demand related revenues.

Response:

FEI interprets the question as referring to the *minimum* contract demand, rather than the maximum.

FEI confirms that the revenue forecast variations captured in this deferral account includes revenue variations on the total forecast LNG fueling station revenues rather than just the revenues in excess of the minimum contract demand related revenues.

112.3 Please identify all of the key factors and risks that would cause variations on the revenue forecast pertaining to the LNG revenue forecasts of $2.9 million in 2012 and $4.4 million in 2013.

[17] The reference to the 2013 forecast LNG revenues in Section 6.3.2.6 on Page 399 of the Application (Exhibit B-1) was incorrect and should have stated $4.1 million

Response:

There are multiple factors which could cause variations in LNG revenue from the forecast amounts of $2.1 million in 2012 and $4.1 million in 2013 included in this Application.[18] In general, these factors include, but are not limited to:

- Commission approval of the CNG / LNG Service Application (currently before the Commission) filed December 1, 2010. FEI recognizes its fueling station business model described therein may be impacted by the Commission's decision;
- Commission approval of a Temporary Service Agreement for LNG Service for Vedder Transport, as well as LNG Delivery by tanker truck, anticipated to be filed in the coming months;
- FEI's ability to negotiate and sign service agreements with new LNG customers, and add incremental load to existing customers (i.e. Vedder);
- Commission approval of future Tariff Supplement filings for LNG projects;
- Resolution of the NGV Incentive Review (currently before the Commission), recognizing EEC incentive funding for NGVs as appropriate. Furthermore, Commission approval of future EEC incentive funding for the period of 2012 and 2013 as requested in this Application;
- The timely and successful completion of the construction of the LNG fueling station project for Vedder Transport, and operational success of the Vedder project. The LNG revenue forecast for 2012 and 2013 are dependent upon Vedder's fueling station as a refuelling site for additional LNG vehicles;
- Significant widening or narrowing of the price differential between LNG and diesel fuel; and
- Changes to the Rate Schedule 16 Variable Charge as described in BCUC IR 1.112.1.

112.3.1 Would the potential absence of EEC incentives for NGV initiatives be one of these key factors?

[18] The reference to the 2013 forecast LNG revenues in Section 6.3.2.6 on Page 399 of the Application (Exhibit B-1) was incorrect and should have stated $4.1 million

Response:

Yes, the potential absence of EEC incentives for NGV incentives would be one of these key factors.

112.3.2 Would the requirement to expand the Tilbury facility to support increased demand for Rate Schedule 16 be another of these key factors?

Response:

While expansion of the Tilbury LNG Facility to accommodate potentially substantial increases in demand for LNG is a possibility, FEI believes that such an expansion is not required at the present time to realize the revenue forecasts within this test period.

To support the Rate Schedule 16 volume forecast in Table I-3 on page 6 of Appendix I of the Application (Exhibit B-1), FEI would need to apply for an increase in the 1,040 GJ daily supply limitation, but not necessarily invest in facility expansion. FEI expects to make an application to the Commission for changes to the daily supply limitation for Rate Schedule 16 by the end of 2011 once the decisions from the Commission related to the CNG and LNG Service Application and the EEC NGV Incentive Review are known.

112.4 Is the proposed expansion of the subject deferral account consistent with the deferral account requested in the December 1, 2010 CNG and LNG Service Application? If so, please explain.

Response:

Yes, 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. It is appropriate to include variations in LNG delivery margin and fueling station revenues from forecast for the reasons as noted in the Application and referenced in the preamble to this question.

112.5 Was the inclusion of variations on the revenue forecasts pertaining to Rate Schedule 16, as requested in this Application, explored or discussed in the CNG and LNG Application dated December 1, 2010?

Response:

This response also addresses BCUC IRs 1.112.5.1, 1.112.5.2, and 1.112.5.3.

Inclusion of variations on revenue forecasts pertaining to Rate Schedule 16 was neither explored nor discussed in the referenced December 1, 2010 Application. The CNG and LNG Service Application chiefly sought approval of a business model for fueling service, and as such, did not seek approval regarding the accounting treatment of Rate Schedule 16 delivery margin revenues. This activity was more appropriately considered in this Application.

Subsequent to the filing of the CNG and LNG Service Application, Vedder Transport purchased 50 LNG trucks for its fleet. As a result of this commitment from Vedder, FEI developed a volume and revenue forecast under Rate Schedule 16 for this RRA that is significantly greater than the LNG volume forecast contemplated in the CNG and LNG Service Application. The change to the volume forecast has resulted in significant increases in the Rate Schedule 16 delivery margin revenue forecasts for 2012 and 2013, increasing from approximately $0.4 million to $1.5 million in 2012 and increasing from approximately $0.7 million to $2.1 million in 2013.

The increase in forecast delivery margin revenue from the CNG and LNG Application to this RRA brought to light the potential significant impact that a variation in LNG agreements may have on the volume and revenue forecast. The existing deferral account, as requested in the CNG and LNG Service Application, would not capture the potential significant benefit of incremental delivery volumes associated with Rate Schedule 16.

FEI believes that the proposed deferral account is the most appropriate way to capture both the benefit of fueling station revenues in excess of minimum contract demand as well as the variances in delivery margin revenue from Rate Schedule 16.

112.5.1 If the answer is "yes", please provide the relevant references in the CNG and LNG Service Application.

Response:

Please refer to our response to BCUC IR 1.112.5.

112.5.2 If the answer is "no", please provide an explanation for why this treatment was not requested as part of the CNG and LNG Service Application.

Response:

Please see our response to BCUC IR 1.112.5.

112.5.3 If there is additional information that has come to light since the CNG and LNG Application was filed that would support the proposed expansion of the subject deferral account, please describe this information.

Response:

Please see our response to BCUC IR 1.112.5.

112.6 Please discuss alternatives to the proposed expansion of the subject deferral account that would address the risks to ratepayers and shareholders with respect to Rate Schedule 16 and fueling station recoveries for CNG and LNG Fueling Service.

Response:

Absent a deferral account mechanism of some form, FEI is not aware of other alternatives that would address the risks and benefits to customers and to the shareholder with respect to Rate Schedule 16 and fueling station recoveries for CNG and LNG Fueling Service. For example,

- One alternative would be not to collect variances in any deferral account. This would not address the risks and benefits to customers or the shareholder resulting from unpredictable variances from forecast.

- Another alternative would be to request a new and separate deferral account designed to accomplish the same objectives but separate from the already proposed deferral account. This achieves the same objectives of the proposed modification to the existing account but results in administrative inefficiency.

FEI believes that the proposed inclusion of Rate Schedule 16 revenue and cost variances in the previously proposed deferral account is the most reasonable and fair method to address the risks and benefits to customers and the shareholder.

113.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.2.6, p. 399

CNG and LNG Service Costs and Recoveries – New/Modified Deferral Account

113.1 Please confirm that by adding the variations from the revenue forecast to the requested deferral account that this will result in all of the risk of this new service being taken on by the ratepayers.

<u>Response:</u>

Confirmed. However, this approach will also give ratepayers the benefit of any revenues not forecast for this new service. One of the benefits of NGV services as a whole is to mitigate the upward pressure on delivery rates for existing customers as a result of declining throughput on the delivery system. Forecast revenues from the NGV service offering, including Rate Schedule 16, are helping to reduce delivery rates to customers for the test period of 2012-2013 (please refer to the response to CEC IR 1.4.1). The proposed deferral account provides the potential for ratepayers to realize further benefits from increased revenues.

The revenue from Rate Schedule 16 that has been forecasted in this application is based on the assumption that incentives for NGV vehicles will continue, the NGV fueling application that is before the Commission will be approved as filed, and the Company will be successful in getting customers to use Rate Schedule 16 through the test period. Currently, no customers are using Rate Schedule 16, but it is expected that Vedder Transport will begin taking service under Rate Schedule 16 later in 2011. Given that the forecast revenues are subject to factors beyond the control of the FEU, a deferral account for the Rate Schedule 16 revenues is therefore appropriate.

113.1.1 What is the impact if this account is not approved?

<u>Response:</u>

If the modification to this account is not approved, any positive or negative variance from the forecast Rate Schedule 16 revenue will flow to the account of the shareholder.

If the original un-modified account is not approved as part of the CNG and LNG Service Application, any revenues earned as a result of any fueling station volumes in excess of minimum contract demand will flow to the account of the shareholder.

114.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.3.7, p. 403

Vancouver Island HST Implementation – New Deferral Account

"In accordance with the proposed treatment of the impact of the HST transition and as indicated in the letter filed with the Commission on September 27, 2010, Vancouver Island has captured the revenue requirement impact of the HST transition in 2010 and 2011, net of implementation costs in an HST Implementation deferral account. The December 31, 2011 closing balance in this account is $133 thousand, net of tax.

In this Application, Vancouver Island is seeking approval for this account and to refund the forecast December 31, 2011 closing balance to customers in rates over a one year period."

"Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers." [Ref: p. 73]

114.1 Please explain how the Company proposes to refund the forecast December 31, 2011 closing balance to customers in rates over a one year period, including which year the refund would affect.

Response:

Please refer to BCUC IR 1.116.3.

The one-year amortization of the Vancouver Island HST Implementation deferral account occurs in 2012 and has been included in the forecast FEVI cost of service for 2012, as demonstrated in Section 7.2 on Schedule 5 (Exhibit B-1), cross referenced to Schedules 28 as well as 68 through 69.

114.2 Please advise when the Company anticipates closing and eliminating this deferral account.

Response:

FEVI has fully amortized this account through the 2012 cost of service so that the opening 2013 balance is zero, and anticipates closing and eliminating this deferral account in FEVI's next revenue requirement application. However, as discussed in Section 5.6.4 of the Application (Exhibit B-1), the forecast 2012 and 2013 cost of service has been determined assuming the continuation of the Harmonized Sales Tax ("HST") at 12 percent and in its current form. Should the HST be repealed or an alternate tax introduced the impact on revenue requirements, including any associated implementation costs, will be assessed and FEVI would propose to include any impacts in this account.

115.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.3.10, p. 404

Customer Service Variance Account – New Deferral Account(s)

"In 2012 and 2013, the Customer Service department will be faced with business uncertainties as discussed in detail in Part 5.3.7 and the Companies are requesting a deferral account to capture actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for the ongoing operating costs of the in-sourced activities, as outlined in Table 5.3-32. The types of uncertainties that the deferral account will address include fluctuations in call volumes, the rate of customer adoption of new communication channels and self serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, and any variances in the anticipated duration required for new staff to become skilled and proficient at their responsibilities.

The variance account will also capture spending variances in meter reading costs primarily due to the timing of BC Hydro's Smart Metering Initiative and its impact on joint gas/electric meter reads in 2012 and the uncertainty of costs in 2013, as an outsourced provider has yet to be confirmed since BCH will not require large scale manual meter reading service at that time.

For purposes of the 2012 and 2013 revenue requirement, additions to this account have not been forecast and the disposition of any balance that accumulates in this account will be addressed in a future revenue requirement application."

115.1 Please explain the magnitude, in terms of the total costs of the Customer Service in-sourcing project, of the "rate of customer adoption of new communication channels and self serve options being offered."

<u>Response:</u>

While it is difficult to assess the magnitude of these costs at this time without first-hand experience of the in-sourced operations, the FEU will be promoting the use of alternative and cost-effective communication channels in the first years of operations, and will be monitoring customer adoption and satisfaction in order to more accurately forecast future impacts in terms of costs.

The FEU will seek opportunities for cost savings associated with the use of communication channels such as e-mail, chat and self-serve alternatives such as online Interactive Voice Response ("IVR"). These services will be available to customers upon go-live and increased use of these services will lead to lower labour costs in the Contact Centres. Electronic billing will also be promoted as it is a more cost-effective alternative to printing and mailing of statements. The FEU believe there are opportunities to save on printing and postage costs, particularly if the Companies can achieve levels comparable to those attained by FortisBC Inc. (electric), which has attained an eleven percent electronic billing use rate (over a three-year period).

115.2 Please confirm the meter reading services are not part of the Customer Service in-sourcing.

Response:

Confirmed, the in-sourcing activities described here do not include the meter reading services.

115.3 Please provide an update on the meter reading contract negotiations, including an assessment of the amount of uncontrollable costs likely to be incurred in 2012 and 2013.

Response:

Meter reading service contracts for 2012 are complete, while the contractual arrangement of services for 2013 is currently underway.

Meter reading services for the 2012 calendar year will be provided by Accenture and BC Hydro. The contracts for these services have been structured to mitigate the risk of any uncontrollable expenses as a result of BC Hydro's Smart Metering deployment initiative, by way of a two-tiered pricing structure for dual reads (gas and electric) and single reads (gas only) in the majority of the FEU's service area. In the event that a difference between actual and forecasted expenditure arises, the FEU believe that it is more likely to be favourable rather than unfavourable, and thereby savings would accrue to customers.

Currently, the FEU are engaged in a Request for Information ("RFI") process to evaluate potential meter reading service providers for 2013 and beyond. A Request for Quotation ("RFQ") process will commence shortly after completion of the RFI process, with the anticipation of vendor selection before the end of 2011 and completed contractual arrangements by early 2012. Although the FEU are in the early stages of the process to confirm service providers for

2013, it believes the forecast $22 million for meter reading services is a reasonable and prudent estimate, as it was derived by using unit rates consistent with gas only reads from the meter reading service agreements signed with Accenture and BC Hydro for 2012. As such, this estimate will be validated throughout the RFI and RFQ processes, and if services are contracted at an amount lower than $22 million for 2013, savings will flow back to customers by way of the proposed deferral account.

115.4 Please comment on whether two deferral accounts, one for the Customer Service in-sourcing and one for the meter reading costs, would be preferable.

Response:

One Customer Service deferral account is preferable for ease of administration, although the Companies plan to track the in-sourcing and meter reading costs separately and the FEU will have the ability to report on the two components if required.

116.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.3.11, p. 405

Vancouver Island Joint Venture Litigation Costs – New Deferral Account

"In this Application, Vancouver Island is seeking approval for a deferral account to capture the legal costs of $130 thousand incurred defending a lawsuit filed by the Vancouver Island Gas Joint Venture (VIGJV). This lawsuit was dismissed in January 2010. The basis of this lawsuit was alleged overpayment of past tolls and declarations for reduction of future tolls. Had the VIJV been successful in their claim, it would have likely resulted in additional costs and a reallocation of cost of service for all other customers. Vancouver Island is seeking approval to amortize this account through delivery rates in 2012."

"Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers." [Ref: p. 73]

116.1 When did FEVI become aware of this proceeding and were any estimates for costs included in the prior RRA for FEVI?

Response:

FEVI received the Writ of Summons and Statement of Claim from the VIGJV in March 2008. However, it was not clear that the VIGJV would pursue the claim until late in 2008 and a trial date was not set until January 2009. The trial date was set for January 2010.

Estimated costs for defending the lawsuit were not included in FEVI's 2010-2011 RRA which was filed in late June 2009. At that time, the FEVI's expectation was that the matter would not go to trial and could not reasonably forecast lawsuit related costs for 2010 and 2011.

116.2 Please explain why these costs from 2009 and perhaps 2010 would not simply be absorbed in those respective years' legal costs.

Response:

From time to time, the FEU are involved in special litigation matters in defence of customer interests. A case in point is the litigation that was brought by the VIGJV alleging they had been overcharged by FEVI notwithstanding they had freely entered into contractual arrangements and then negotiated an extension of the terms of the contract in exchange for a reduction in the minimum demand under the contract.

Had the VIGJV been successful, the judgement would have resulted in a reversal of revenues previously booked by FEVI and creation of a deficit that would have been captured in the Revenue Deficiency Deferral Account, which would have been recovered from all customers. While unspecified in the claim, we were advised by the VIGJV counsel that they were seeking to recover in excess of $20 million.

FEVI defended successfully against the claim for the sole benefit of the customers on the system. Such defence costs represent extraordinary costs that should properly fall outside of normal O&M expenditures and the Commission has historically allowed such costs to be netted against recoveries and/or recovered from customers through the use of deferral accounts.

In the case of FEI, the Province had imposed a PST assessment of approximately $37.1 million on the Southern Crossing Pipeline project. FEI mounted a defence against the assessment and made a provisional payment of $10 million which the Commission allowed to be captured in a rate base deferral account. Subsequently, the assessment was reduced by ministerial order to approximately $7.0 million with a refund being credited to the deferral account. This judgement was successfully appealed and the assessment overturned with most of the remaining balance refunded to FEI and credited to the deferral account. The costs of defending these assessments, approximately $450 thousand net of tax at January 2011, remained in the deferral account for recovery from customers.

FEVI submits that the extraordinary costs of defending against the VIGJV lawsuit should properly be recovered from customers who stood to benefit from their incurrence (and in fact did, though that is not the prime determining factor here). FEVI, in preparing its O&M budgets, only forecasts costs associated with legal services for normal course activities. FEVI is not in a position to forecast costs relating to lawsuits brought by third-parties unexpectedly and, as such, would never be in a position to recover such costs of doing business and have an opportunity to earn its allowed return unless the Commission provided the type of relief sought with respect to the costs associated with this lawsuit.

116.3 Please explain how the Company proposes to amortize this account through delivery rates in 2012 should the rate freeze be maintained.

Response:

The FEVI rate freeze is maintained by drawing down the forecast December 31, 2011 surplus balance in the RSDA. That is, as long as the surplus balance in the RSDA account is greater than the forecast revenue deficiency for that year, a rate freeze can be maintained. The revenue deficiency for each year is determined by comparing the forecast cost of service to the forecast revenue at existing rates. Please refer to Table 3.4-1 on page 73 of the Application (Exhibit B-1) for the RSDA account continuity, including the impact to the account of the forecast revenue deficiency for 2013.[19]

FEVI has determined the forecast cost of service for 2012 and 2013 inclusive of all forecast costs and other revenues identified in the Application (Exhibit B-1), including the amortization of all applicable deferral accounts such as the Vancouver Island Joint Venture Litigation Cost deferral account, as demonstrated in the Application (Exhibit B-1), Section 7.2 on Schedules 5 and 6, cross referenced to Schedules 28 and 29 as well as Schedules 68 through 71.

116.4 Does FEU believe that whenever actual costs are incurred above the forecasted amount, the utility should be able to create a deferral account to capture costs?

Response:

No. The FEU do not believe that whenever actual costs are incurred above the forecast amount (in this case there was no forecast amount), that a deferral account should be requested.

The FEU have guidelines that are followed in initiating a request for a deferral account. As outlined on page 384 of the Application (Exhibit B-1), deferral accounts are maintained to decrease rate volatility, deal with changing energy policy, address non-controllable or non-recurring items, and capture costs of applications. The VIGJV Litigation Costs deferral account falls into the category of non-recurring and non-controllable costs. The costs were incurred to protect previously approved revenues collected from the VIGJV that, had the VIGJV been successful in their action, would have had to be collected from all other customers. The FEU will continue to request deferral accounts to deal with costs and revenues of this nature and believe these deferrals continue to add value for customers and protect shareholder's interests as well.

[19] The forecast revenue deficiency for 2012 is $4 thousand as shown in Tab 7.2, Schedules 2 and 5; therefore, for all intents and purposes, the revenue at existing rates is equal to the forecast cost of service for 2012.

In respect of this request for the VIGJV legal cost deferral, FEVI acknowledges that with hindsight it would have been preferable had the request for the deferral account been made in 2009. FEVI's view was that the case was without merit and had originally felt it would not advance. These costs do not relate to a variance from a forecasted cost as no forecast was made or reasonably determinable at the time. By the time it became apparent that FEVI would incur costs to defend the suit, the revenue requirements process was well under way and FEVI did not want to prejudice the outcome of the dealings with the VIGJV by raising it during the RRA process.

While we believe for the reasons already stated that these costs should appropriately be borne by customers, we have considered the request in light of the questions asked and acknowledge that the request could be seen to amount to retroactive ratemaking. On that basis, we respectfully withdraw the request. Should FEVI face similar situations in the future it will seek approval to capture legal costs of this nature in a deferral account once it is clear that a defence may be required.

116.5 FEU's actual EEC expenditures were less than forecasted during the 2010 year. Based on the same reasoning included in the Application, should the rate impact for any unspent costs be deferred in a similar fashion?

Response:

The rate impact of unspent 2010 and 2011 EEC costs should be not be deferred. The treatment of 2010 and 2011 EEC expenditures for FEVI and FEI are in accordance with the Negotiated Settlement Agreements as approved by Commission Orders No. G-140-09 No. G-141-09, as well as in accordance with Commission Order No. G-36-09, which approved the inclusion of the forecast EEC deferral account balances in rate base.

In this Application, the FEU have proposed a modification to the EEC deferral account mechanism for 2012 and 2013 to address variances in the level of customer participation which may lead to unspent costs.

Please refer to BCUC IR 1.116.4 for a discussion on the FEU's use and review of deferral accounts.

117.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.5.6, pp. 409-410

Gains and Losses on Asset Disposition – Modified Deferral Account

"IFRS require that gains and losses on disposal of assets be recognized in the income statement. As approved by Commission Order G-141-09 for Mainland, Commission Order G-140-09 for Vancouver Island and Commission Order G-138-10 for Whistler, the Companies will continue to defer the amount of these gains and losses during the term of this Application, for recovery in future years. The Companies do not forecast gains or losses on asset disposals; however, we request Commission approval for any gains and losses incurred during 2012 and 2013 to be included in this rate base deferral account, consistent with the treatment in 2010 and 2011.

In this Application the Companies are seeking approval to transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on Asset Disposition account and to amortize the total balance in this account in delivery rates over 20 years, aligned with the average service life of the asset categories that are contributing to the losses."

117.1 Please confirm the forecast balance in the Gains and Losses on Asset Disposition account as of December 31, 2011 is $17.923 million, and the proposed transfer from the IFRS Transitional account is a credit of $6.675 million. If this assumption is not correct, please explain what the correct assumption is.

<u>Response:</u>

FEI confirms that the forecast balance in the Gains and Losses on Asset Disposition account as of December 31, 2011 is $17.923 million. The proposed transfer from the IFRS Transitional account on January 1, 2012 is a credit of $6.575 million (not $6.675 million).

117.2 Please confirm the credit of $6.675 million is all related to Gains and Losses on Asset Disposition, and confirm the time period in which they were incurred. If they are not related to Gains and Losses on Asset Disposition, then please explain what the credit is related to.

Response:

This response assumes that the $6.675 million referenced above pertains to the $6.575 million in this Application (Exhibit B-1), Section 7, Tab 7.1, Schedule 69. The credit of $6.575 million represents the January 1, 2010 transfer of existing gains for general plant accounts from accumulated depreciation to the IFRS Transitional Deferral Account, as approved by Commission Order No. G-140-09. In this Application, FEI has requested that this balance be closed into the Gains and Losses on Asset Disposition deferral account, as discussed in Section 6.3.5.6 of this Application.

117.3 Please explain if losses from asset dispositions occurred in 2010 and 2011, what assets incurred the losses and if any of these assets were retired before the end of their economic useful lives, why.

Response:

Provided below is a summary of asset retirements for 2010 actual and 2011 projection, with any associated amounts of unrecovered depreciation ("losses") recorded in the approved deferral account (Gains and Losses on Asset Disposition).

As noted in the response to BCUC IR 1.136.2, a "loss" in the case of the FEU's assets, is defined as the difference between the remaining net book value of an asset and any salvage proceeds. As depreciation expense is recorded based on an estimated depreciation rate, a "loss" results primarily from the difference between the actual life of an asset and the estimated life on which the depreciation rate is based. Over the life of an asset, many factors beyond the FEU's control can influence an asset's life. For each of the asset classes shown in the tables below, the "loss on retirement" indicates that as a whole the assets in that class were not fully depreciated at the time of retirement. This does not indicate that they were retired before the end of their economic useful lives, but only that the historically approved depreciation rates were not adequate to recover their cost over the period of time that they were in service.

For FEI, the asset classes with the majority of the unrecovered depreciation reported include 473 Services, 474 Meter Installations and Regulators, 475 Mains and 478 Meters. These are the same asset classes that have experienced the majority of the "losses" reported in the past. Further explanations and reasons for this trend are contained in the Asset Loss report included in the Application (Appendix B-1), Appendix E-3.

FEI	2010	2011 Projection *
Asset class	**Loss on retirement**	**Loss on retirement**
402-01 Application Software - 12.5%	-	-
460-00 Land in Fee Simple	(39)	-
461-00 Transmission Land Rights	(35)	-
465-00 Mains	38	-
466-00 Compressor Equipment	296	-
467-10 Measuring & Regulating Equipment	43	-
467-20 Telemetering	-	8
470-00 Land in Fee Simple	(63)	-
472-00 Structures & Improvements	(5)	-
473-00 Services	1,983	2,396
473-00 Services - LILO	40	37
474-00 House Regulators & Meter Installations	8,383	1
475-00 Mains	634	598
475-00 Mains - LILO	0	17
477-10 Measuring & Regulating Equipment	79	49
477-20 Telemetering	1	-
478-10 Meters	3,475	-
484-00 Vehicles	(15)	(0)
Total	**14,817**	**3,106**

* As shown in the 2012 - 2013 Revenue Requirement Application, Section 7, Tab 7.1, Schedule 67, Line 12

FEVI	2010	2011 Projection *
Asset class	**Loss on retirement**	**Loss on retirement**
463-00 Measuring Structures	83	-
467-10 Measuring & Regulating Equipment	280	-
468-00 Communication Structures & Equipment	13	-
473-00 Services	138	-
475-00 Mains	68	-
477-10 Measuring & Regulating Equipment	0	-
484-00 Vehicles	76	-
485-10 Heavy Work Equipment	1	-
Total	**660**	**-**

* As shown in the 2012 - 2013 Revenue Requirement Application, Section 7, Tab 7.2, Schedule 67, Line 12

FEW	2010	2011 Projection *
Asset class	**Loss on retirement**	**Loss on retirement**
472-00 Structures & Improvements	0	-
473-00 Services	2	-
475-00 Mains	114	-
477-10 Measuring & Regulating Equipment	13	-
482-00 Structures & Improvements	3	-
Total	**132**	**0**

* As shown in the 2012 - 2013 Revenue Requirement Application, Section 7, Tab 7.3, Schedule 67, Line 15

117.4 Please confirm that any losses incurred in 2010 and 2011 did not include salvage or retirement costs.

Response:

The FEU confirm that any losses incurred in 2010 and 2011 are net of salvage proceeds (as per GAAP) but not removal costs. Removal costs in excess of the amount approved for recovery in rates are included in the Deferred Removal Costs account. Please also refer to BCUC IR 1.117.3.

117.5 Does FEU forecast any gains/losses on retirement in 2012 and 2013? If so, what are they?

Response:

The FEU do not forecast any gains/losses on retirement in 2012 and 2013. The FEU are not aware of any asset disposals that would result in gains or losses being recognized, since the FEU are unable to determine which specific assets will be retired over the forecast period.

118.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.5.11, pp. 411-415

Gas Asset Records Project – New Deferral Account

"Governments, Regulators, codes, and best practices have always required that pipeline operators collect, retain and manage records pertaining to their gas system assets. Due to more recent events and resulting public pressure, more stringent requirements have been put in place related to the collection, retention and management of gas system asset records."

"The FortisBC Energy Utilities have been and will continue to be diligent about the collection, retention and management of gas system records. We have records in various systems, locations and formats dating back to the original construction of our gas systems."

118.1 Please describe what "plans and programs [the Company has] in place for the management of their pipeline system in the absence of these records as well as programs for reestablishment of the records".

<u>Response:</u>

FEI manages its pipeline systems with the compliance records that were and are created, captured and retained as required by regulation at the time of construction of the gas system asset(s). Management of historic compliance records has been in various systems, locations and formats that make it difficult and time consuming to locate and retrieve some compliance records, control record security, and manage records through their life cycle.

One of the key outcomes of the Gas Assets Records Project is to establish the completeness of our existing compliance records to the extent that we can. Having the relevant gas system historic compliance records located and catalogued in FileNet will enhance one of the key pillars associated with the safe and reliable management of our gas systems.

Currently, when we encounter a situation during the planning and design phase of capital projects that a record needs to be established or re-established, those records are established or re-established under the capital project. The Gas Asset Records Project is not requesting any funding to establish or re-establish any historic records. The Gas Asset Records Project will gather historic records from various sources and formats, review and classify them, and move them into FileNet.

118.2 Please advise if the Company has records that "are incomplete due to asset transfers or other reasons." If so, how is the Company able to manage in the absence of these records and how are those records being recovered?

Response:

Please refer to the response to BCUC IR 1.118.1.

118.3 Please comment on the Company's current policies with respect to "retention of complete project documentation … for a minimum period of 10 years."

Response:

In general, the FEU's current policy is to retain gas system specific project documentation for twenty five years after the asset is physically removed. The only exception to this retention period is radiographs[20] used for weld inspection which are only retained for five years since their quality deteriorates after that time.

> *"To take the collection, retention and management of our gas system asset compliance records to the next level of performance, we are seeking approval for the creation of a deferral account to capture and recover the costs of this project, as outlined in Table 6.3-14. The costs to be incurred under this Project are one time in nature and have lasting value for customers, and are more appropriately reflected in a deferral account than through an increase in the base level of O&M. This will allow the Utilities to spread the costs out over a longer period better matching with the period that benefits will be realized."*
>
> *"The FEU has been working diligently for quite some time on the management of our gas system asset compliance records. We introduced the FileNet technology, reviewed and assed the state of our historic records and are now seeking funding to complete the work we started in a timely and systematic manner."*

The costs in Table 6.3-14 range from $1.4 million to $2.25 million per year over four years from 2012 to 2015.

[20] A radiograph is a photographic image produced by the action of x-rays or nuclear radiation.

"[w]e are requesting approval for up to $7.8 million for the four year period ending December 31, 2015 and to manage these costs within the framework of a deferral account mechanism, to be amortized in delivery rates over five years, commencing January 1, 2012. FEU believe that a five year amortization period is appropriate because it mitigates the rate impacts of the costs and generally coincides with the period over which the costs are incurred. The $7.8 million is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers."

118.4 Please expand on the on-going implications of this project, including items such as future savings from record storage and staff time to retrieve and distribute technical records.

Response:

The Gas Asset Records Project will have five positive on-going implications.

First, the project will significantly improve the security, retrievability, accessibility, and management of our gas system asset records.

Second, the project will provide one consistent and common source for gas system asset records that we can refer to during events such as audits, emergency response, and operational inquiries.

Third, the project will enhance our engineering process by reducing the search/retrieval time and effort by staff to find the appropriate gas asset records. For example, our engineering staff will be able to find gas system asset records in one location instead of having to look in 14 different locations as they are currently required to do. The savings in time could be from minutes to hours depending on the size and nature of the project.

Fourth, the project will enhance our emergency response where access to detailed gas system asset records is required. Detailed gas system asset records will be readily searchable and available electronically to everyone across the organization instead of having to consume precious emergency response time to manually find these records. Our ability to quickly access our gas system asset records and respond to emergencies may reduce the time required to shut off the gas, reduce the volume of gas vented to the atmosphere and reduce the cost of lost gas.

Finally, the project will marginally reduce our off-site storage requirements and make office space available for uses other than storage.

Note that cost savings associated with the Gas Asset Records Project are primarily capital in nature because historical records are normally used in the planning of projects and, for the most part, the staff using these records charge their time to capital projects. The variable nature of our gas system and future projects makes it difficult to quantify the savings.

118.5 Please explain, given the current state of the FileNet Records project, if the remaining costs are viewed as uncontrollable or difficult to anticipate or estimate?

Response:

The FEU have classified the requested Gas Asset Records Project deferral account in the category of "other deferrals". The "other" category of deferrals, as stated on page 384 of the Application (Exhibit B-1), is intended for "various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature". As stated on page 413 of the Application (Exhibit B-1), "The costs to be incurred under this Project are one-time in nature and have lasting value for customers…". Therefore the FEU are requesting deferral account treatment to reflect the one-time nature of these costs, and the ongoing value for the safety of the system, not because the costs are viewed as uncontrollable.

The forecast costs are difficult to anticipate rather than uncontrollable, due to the unpredictable state of the documents and the varying effort needed to interpret historic drawings and gas system asset records from multiple companies, locations, and record keeping systems. Given these parameters, we have provided the best cost estimate based on our three years of experience with the implementation of our records management system and our knowledge of the historic gas system asset records. The use of a deferral account ensures that customers pay only for the actual costs incurred, helping to mitigate some of the uncertainty around future cost estimation.

118.6 Please explain, given the four year projected project timeframe, the roughly equal cost per year, and the proposed five year amortization over the same time period, plus one year, why the project is not simply carried out through regular O&M?

Response:

As explained in the Application, the FEU believe these costs meet the guidelines for deferral account treatment. Although the costs associated with the Gas Asset Records Project are one-time in nature, they provide lasting benefits. It therefore makes sense to spread the costs out over a longer period than just the period in which the costs are incurred. As displayed in the following table, an amortization period of five years does not result in the costs being spread over five years from 2012 to 2016, but rather over a period of eight years since the 2015 additions do not become fully amortized until 2019. The FEU believe this project will have longer-term benefits beyond 2019; however, a five year amortization period for the deferral account provides a reasonable balance between mitigating rate impacts for our customers and the timely recovery of costs.

	2012	2013	2014	2015	2016	2017	2018	2019
Opening Balance	$ -	$ 1,200,000	$ 2,250,000	$ 2,902,500	$ 2,782,500	$ 1,612,500	$ 742,500	$ 210,000
Additions	2,000,000	2,250,000	2,150,000	1,400,000	-	-	-	-
Tax	- 500,000	- 562,500	- 537,500	- 350,000	-	-	-	-
Net Additions	1,500,000	1,687,500	1,612,500	1,050,000	-	-	-	-
Amortization	- 300,000	- 637,500	- 960,000	- 1,170,000	- 1,170,000	- 870,000	- 532,500	- 210,000
Closing Balance	$ 1,200,000	$ 2,250,000	$ 2,902,500	$ 2,782,500	$ 1,612,500	$ 742,500	$ 210,000	$ -

118.7 Please confirm, that using a deferral account in the manner requested, the entire risk of this project is borne by the ratepayers.

Response:

Yes the actual project costs will be paid by customers as the costs are part of providing safe, reliable utility service. The FEU believe that this project provides lasting benefits for customers and regardless of whether the Gas Asset Records Project costs were forecast as O&M or deferral, the same expenditure amount would be forecast for 2012 and 2013. In addition to the rate mitigation benefits, the advantage of the deferral treatment for customers is that the deferral account balance will continually be trued up to actual and re-forecast for Commission approval with each rate filing. That is, customers will only pay actual costs as prudently incurred. As discussed in response to BCUC IR 1.6.5, for all types of costs (i.e. O&M, Capital, Deferral), the FEU endeavour to ensure the costs are prudently incurred.

119.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.5.12, pp. 415-418

BCOneCall Project – New Deferral Account

"The Technology Stream will be completed by mid 2011 and is being funded through our IT capital process. The Technology Stream provides technology enhancements, integrations and process improvements necessary to automate a portion of the BCOneCall ticket process."

"The Conflation Stream will import the most current landbase available for the FEI service territory and shift the FEI gas mains/assets so that they correctly align with this new landbase. This stream of the project is necessary because the gas mains in the AMFM system are attached to a landbase that is about 8 years old and somewhat out of date. Having the most current Municipal landbase is essential to the successful automation of the BCOneCall process."

"The BCOneCall Ticket Process Improvement project offers a significant financial benefit that will see a reduction in our long term O&M costs required for processing BCOneCall tickets. The source of this financial benefit is from the direct reduction of the average ticket processing time by up to 34.7 percent as a result of automation. This equates to a decrease in processing time of up to 10.9 minutes (from the current average of 31.5 minutes). This processing time reduction is estimated to result in an average $540 thousand annual sustainable O&M savings per year after 2014 - once the project is fully implemented and stabilized."

119.1 Please explain further the actual work to be completed in the "Data Consistency" and "Conflation" streams of the project. For example, whether the work is to develop a new system/process or whether the work is to make changes to data, the former usually a capital item and the latter an O&M item.

Response:

The "data consistency" and "conflation" streams of the project represent changes to data or data sets. An example of "data consistency" work is populating key service information in the existing AMFM database so that we can create standard service location lists using our Service Information Application ("SIA") for our customers. With these lists, we will be able to:

- Improve the efficiency of responding to multi-address BCOneCall requests (the standard service lists reduce the volume of documents required to respond to multi-address BCOneCall requests);

- Provide clear and easily understood information for larger projects; and
- Provide a consistent response to BCOneCall requests across our service territory.

The "conflation" work under that stream will see the importing of the new municipal landbase and the shifting of features (ie: lines representing our gas mains, dimensioning information, text) associated with the representation of our gas plant in our GIS system to align with the new more accurate landbase.

The "data consistency" and "conflation" initiatives are critical for the FEU to realize the estimated savings from this project.

In general, activities and costs related to constructing an asset (i.e. software) and making it available for use are accounted for as capital, whereas activities and costs related to converting existing data is considered O&M. The FEU consider the work streams described above, data consistency and conflation, as O&M in nature as the work is focused on updating existing records and information. Under US GAAP, there would be a similar accounting treatment.

The circumstances of each situation must be considered in determining whether activities are accounted for as capital in nature.

119.2 Please explain if the Municipal landbase data in the AMFM system is the same one used by the GIS operators for regular construction and repair work of the utility. If so, why has this out of date data not been an operational problem over the last eight years? Please explain how the Municipal landbase data gets refreshed.

<u>Response:</u>

The AMFM landbase used in the BCOneCall process is the same one used by the GIS operators for regular construction and repair work of the utility. The out-of-date landbase has been an operational problem over the last eight years and we have done our best to resolve those problems, on an as-needed basis, to continue to operate our gas systems in a safe and reliable manner. For example, we update our landbase in the immediate area where we require construction drawings for a specific job. This approach ensures that we provided accurate and current landbase information on the drawings for construction jobs. Changes to other parts of our landbase would only be made when a construction job triggered an update to a specific area.

Our ability to refresh and update our landbase globally was limited by two factors. First, current and accurate landbase from all the Municipalities and Regional Districts was not available in a coordinated and standard manner. This matter has been largely resolved by our membership in the Integrated Cadastral Information Society ("ICIS"), a non-profit organization, that has "*facilitated the collaborative integration and maintenance of timely, accessible and accurate province-wide spatial data*"[21]. Second, technology and expertise has not been available to allow the efficient alignment of mass quantities of data with new municipal landbase. This technology and expertise is now available.

After conflation, we will be able to refresh our entire landbase using basic GIS tools.

119.3 Please identify the departments and/or divisions where the annual savings will result in 2015, including the resource codes. Please confirm the Company will undertake to deliver these savings irrespective of the type of regulation (such as PBR) following 2014.

<u>Response:</u>

The anticipated labour savings as a result of the BCOneCall Project of approximately $540 thousand are expected to occur in the Operations Engineering department. The savings are expected to occur in the COPE Costs resource code and are associated with the reduced number of seasonal employees who will be required to process peak ticket volumes.

The FEU confirm that the savings will reduce future O&M forecasts that will be included in the determination of cost of service for the FEU. The treatment of any potential future PBR-type of savings related to O&M will be determined in a future regulatory proceeding and will be subject to Commission approval at that time.

[21] http://www.icisociety.ca/about-icis/overview.htm

120.0 Reference: Rate Base

Exhibit B-1, Application, Part 6.3.6, p. 418

Earnings Sharing Mechanism – Residual Deferral Account

In the NSA attached to Commission Order No. G-141-09, an Earning Mechanism Sharing Account was identified that envisioned return of *"the projected balance of the Earnings Sharing deferral account at the beginning of 2010 to customers through Rate Rider 3 over the two year term of this RRA, along with the end-of-term capital incentive mechanism amount. Any variances between the projected amount and the amount determined based on final rate base and earnings figures for 2009, will be adjusted through the rider in 2011."*

120.1 Please advise as to the resolution of the Earnings Sharing Account and the end-of-term capital incentive mechanism amount.

<u>Response:</u>

The Earnings Sharing Mechanism/Capital Incentive Mechanism deferral account is currently being refunded to customers through the approved delivery rate rider (Rider 3). FEI is forecasting that the entire balance of the Earnings Sharing Mechanism/Capital incentive Mechanism deferral account will be returned to customers through Rider 3 by December 31, 2011. This is reflected on the deferral continuity schedule in Section 7, Tab 7.1, Schedule 67 of this Application (Exhibit B-1).

FEI acknowledges that a residual balance may exist in this deferral account at the end of 2011 as a result of variances in actual volume compared to volumes as forecast; however, the balance, if any, will likely be immaterial and disposition will be addressed in a future application.

121.0 Reference: Embedded Cost of Long-term Debt

Exhibit B-1, Application, Section 5.7, pp. 309-312; Section 7, Tab 7.4, Schedules 82-84

Average Principal Outstanding and Annual Cost – Fort Nelson

121.1 On the schedules above, average Principal Outstanding and Annual Costs columns do not add to the totals shown. Please revise the schedule to show the correct totals.

Response:

On Schedules 82-84 for Fort Nelson (Application, Exhibit B-1, Section 7, Tab 7.4) the average Principal Outstanding and the Annual Costs do not add to the totals shown because the row containing the average Principal Outstanding and Annual Costs associated with the LILO Debt Obligations has been inadvertently hidden. Please refer to Schedules 82-84 for Mainland (Section 7, Tab 7.1), which are identical to Schedules 82-84 for Fort Nelson. On the Mainland schedules, the rows are not hidden.

Amended Schedules 82-84 for Fort Nelson will be included in the financial schedules submitted when Fort Nelson files an Evidentiary Update.

121.2 On Schedule 83, it appears that the Annual Cost for the 2011 Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. In addition, based on the revised total for Annual Cost and the actual total of Average Principal Outstanding, it appears that the average embedded cost should be 6.83%, a difference of 9 basis points from the rate computed by Fort Nelson. If appropriate, please revise the schedule to show the correct amounts and all other schedules that would use these amounts (e.g. Schedules 80 and 5).

Response:

On Schedule 83 for Fort Nelson the Annual Cost for Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. The stated amount of $2,860,000 incorrectly calculates interest for only a partial year rather than a full year. In itself, this will increase the Average Embedded Cost of Long-term Debt for Fort Nelson for 2012 to 6.86 percent from 6.73 percent, increasing the revenue deficiency in 2012 by approximately $7 thousand.

All financial schedules impacted by this oversight will be amended and submitted when Fort Nelson files an Evidentiary Update.

121.3 On Schedule 84, it appears that the Annual Cost for the 2011 Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. In addition, based on the revised total for Annual Cost and the actual total of Average Principal Outstanding, it appears that the average embedded cost should be 6.84 percent, a difference of 10 basis points from the rate computed by Fort Nelson. If appropriate, please revise the schedule to show the correct amounts and all other schedules that would use these amounts (e.g. Schedules 81 and 6).

<u>Response:</u>

Please refer to BCUC IR 1.121.2.

Because the same oversight occurred in both 2012 and 2013, it does not result in a further incremental revenue deficiency in 2013.

All financial schedules impacted by this oversight will be amended and submitted when Fort Nelson files an Evidentiary Update.

122.0 Reference: Embedded Cost of Long-term Debt

Exhibit B-1, Application, Section 5.7, pp. 309-312; Section 7, Tab 7.1, Schedules 82-84

Average Principal Outstanding and Annual Cost – FEI-Mainland

122.1 Average Principal Outstanding (on Schedule 82) and Annual Costs (Schedules 83 and 84) columns do not appear to add to the totals shown. Please revise the schedule to show the correct totals.

Response:

The Average Principal Outstanding on Schedule 82 and the Annual Costs on Schedules 83 and 84 for FEI Mainland do add to the totals shown. There is no revision required to Schedules 82 to 84 for FEI Mainland in this respect. However, please see the response to BCUC IR 1.122.3 and BCUC IR 1.122.4 pertaining to Schedules 83 and 84 for FEI Mainland.

122.2 On Schedule 82, it appears that the Average Principal Outstanding does not add to the total shown, the average embedded cost appears to be 7.74%, a difference of 80 basis points from the rate computed by FEI-Mainland. If appropriate, please revise the schedule to show the correct amounts and all other schedules that would use these amounts (e.g. Schedules 79 and 4).

Response:

The Average Principal Outstanding on Schedule 82 for FEI Mainland adds to the total shown. The Average Embedded Cost of 6.94 percent is correct as shown. No revision to Schedule 82 for FEI Mainland is required.

122.3 On Schedule 83, it appears that the Annual Cost for the 2011 Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. In addition, based the revised total for Annual Cost, the average embedded cost appears to be 6.86%, a difference of 13 basis points from the rate computed by FEI-Mainland. If appropriate, please revise the schedule to show the correct amounts and all other schedules that would use these amounts (e.g. Schedules 80 and 5).

Response:

On Schedule 83 for FEI Mainland the Annual Cost for Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. The stated amount of $2,860,000 incorrectly calculates interest for only a partial year rather than a full year. In itself, this will increase the Average Embedded Cost of Long-term Debt for FEI Mainland for 2012 to 6.86 percent from 6.73 percent, increasing the revenue deficiency in 2012 by approximately $2.0 million.

All financial schedules impacted by this oversight will be amended and submitted when FEI files an Evidentiary Update.

122.4 On Schedule 84, it appears that the Annual Cost for the 2011 Medium Term Debt Issue – Series 25 should be $4,878,000 instead of $2,860,000. In addition, based on the revised total for Annual Cost and the actual total of Average Principal Outstanding, the average embedded cost it appears that be 6.87%, a difference of 13 basis points from the rate computed by FEI-Mainland. If appropriate, please revise the schedule to show the correct amounts and all other schedules that would use these amounts (e.g. Schedules 81 and 6).

Response:

Please refer to BCUC IR 1.122.3. Because the same oversight occurred in both 2012 and 2013, a further incremental revenue deficiency in 2013 does not result.

All financial schedules impacted by this oversight will be amended and submitted when FEI files an Evidentiary Update.

123.0 Reference: Utility Income and Earned Return

Exhibit B-1, Application, Section 7, Tab 7.4, Schedules 5, 31

Impact of Error in Summation of Utility Revenue for 2011 Projected

123.1 Schedule 4 shows a RSAM revenue credit for 2010 and 2011, but the RSAM is not shown in Schedule 5 for 2011. If this is an error, please correct Schedule 5 and make any adjustments that are required to other Schedules.

Response:

The RSAM revenue credit (line 14) was inadvertently hidden in Schedule 5 and 6 for FEI, Whistler, and Fort Nelson. The 2011 projected total revenue does, however, include the RSAM revenue credit (Schedule 5, line 19). This hidden row does not impact the revenue deficiencies or rate proposals.

The amended schedules will be submitted when the Utilities file an Evidentiary Update.

124.0 Reference: Cash Working Capital

Exhibit B-1, Application, Section 6.1.9.1, pp. 329-330; Section 7, Tabs 7.1- 7.4, Schedules 75-77

Historical Information on Cash Working Capital, Revenues, and Expenses

124.1 Please provide information on 2008, 2009 and 2010 actuals for Schedule 75, by completing the following for each utility:

	2008			**2009**			**2010**		
	Days	**Expenses**	**Cash Working Capital**	**Days**	**Expenses**	**Cash Working Capital**	**Days**	**Expenses**	**Cash Working Capital**
Cash Working Capital:									
Revenue lag days									
Expense lead day									
Net lead/(lag) day									
Cash Working Capital, Revised Rates:									
Revenue lag days									
Expense lead days									
Net lead/(lag) days									
Cash Working Capital Change									

Response:

Please note the table requests Cash Working Capital details both at existing rates and at revised rates. However, historic actuals are only available at revised rates so only the rows asking for revised rates have been completed.

Revisions to the Lead Lag days were implemented for FEI, FEVI and FEW in 2010; therefore the results shown for 2008 and 2009 are not comparable to 2010 for these utilities. Please refer to the statement below provided in the 2010/2011 FEVI RRA, Appendix I-2, Lead Lag Study, Section III, Page 8.

> *"In past TGVI lead/lag studies the weighted average total Revenue lag days was deducted from each of the component Expense lead days rather than from the total Expense lead days as is done in this study. Either methodology yields the same Cash Working Capital requirements."*

Prior to 2010 FEVI and FEW calculated Cash Working Capital on a net of revenue basis. As such, not all FEVI and FEW actuals for 2008 and 2009 could be completed.

FEI - 124.1	2008			2009			2010		
($000s)									
	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital
Cash Working Capital:									
Revenue lag days									
Expense lead day									
Net lead/(lag) day									
Cash Working Capital, Revised Rates:									
Revenue lag days	35.0	$ 1,691,366		35.0	$ 1,466,404		38.8	$ 1,332,490	
Expense lead day	39.4	$ 1,444,820		39.2	$ 1,289,501		37.5	$ 1,180,347	
Net lead/(lag) day	(4.4)		$ (17,417)	(4.2)		$ (14,838)	1.3		$ 4,204
Cash Working Capital Change									

FEVI - 124.1	2008			2009			2010		
($000s)									
	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital
Cash Working Capital:									
Revenue lag days									
Expense lead day									
Net lead/(lag) day									
Cash Working Capital, Revised Rates:									
Revenue lag days							39.2	$ 211,315	
Expense lead day		$ 189,224			$ 176,924		33.9	$ 148,856	
Net lead/(lag) day			$ 4,965			$ 4,702	5.3		$ 2,163
Cash Working Capital Change									

FEW - 124.1	2008			2009			2010		
($000s)									
	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital
Cash Working Capital:									
Revenue lag days									
Expense lead day									
Net lead/(lag) day									
Cash Working Capital, Revised Rates:									
Revenue lag days							38.7	$ 13,623	
Expense lead day		$ 15,761			$ 13,003		36.6	$ 10,764	
Net lead/(lag) day			$ 136			$ 64	2.1		$ 60
Cash Working Capital Change									

Fort Nelson - 124.1	2008			2009			2010		
($000s)									
	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital
Cash Working Capital:									
Revenue lag days									
Expense lead day									
Net lead/(lag) day									
Cash Working Capital, Revised Rates:									
Revenue lag days	35.1	$ 5,717		34.9	$ 5,285		34.9	$ 4,647	
Expense lead day	37.4	$ 5,488		36.8	$ 5,133		36.4	$ 4,691	
Net lead/(lag) day	(2.3)		$ (35)	(1.9)		$ (27)	(1.5)		$ (19)
Cash Working Capital Change									

124.2 Please provide information on 2008, 2009 and 2010 actuals for Schedule 76, by completing the following for each utility:

	2008			**2009**			**2010**		
	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days
Revenue:									
Total Gas Sales									
Total Revenue									
Revenue, Revised Rates:									
Total Gas Sales									
Total Revenue									

Response:

As discussed in response to BCUC IR 1.124.1, only actuals at revised rates have been provided, certain information is not available for FEVI and FEW for 2008 and 2009, and 2010 results are not comparable to 2008 and 2009.

FEI - 124.2	2008			2009			2010		
($000s)									
	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days
Revenue:									
Total Gas Sales									
Total Revenue									
Revenue, Revised Rates:									
Total Gas Sales	$ 1,672,872	35.0	$ 58,535,631	$ 1,448,786	35.0	$ 50,770,476	$ 1,314,355	38.8	$ 50,972,760
Total Revenue	$ 1,691,366	35.0	$ 59,148,613	$ 1,466,404	35.0	$ 51,356,612	$ 1,332,490	38.8	$ 51,667,331

FEVI - 124.2	2008			2009			2010		
($000s)									
	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days
Revenue:									
Total Gas Sales									
Total Revenue									
Revenue, Revised Rates:									
Total Gas Sales							$ 193,410	38.7	$ 7,477,889
Total Revenue							$ 211,315	39.2	$ 8,289,723

FEW - 124.2	2008			2009			2010		
($000s)									
	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days
Revenue:									
Total Gas Sales									
Total Revenue									
Revenue, Revised Rates:									
Total Gas Sales							$ 13,587	38.7	$ 525,811
Total Revenue							$ 13,623	38.7	$ 527,207

Fort Nelson - 124.2	2008			2009			2010		
($000s)									
	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days	Revenue	Lag Days Service to Collection	Dollar Days
Revenue:									
Total Gas Sales									
Total Revenue									
Revenue, Revised Rates:									
Total Gas Sales	$ 5,682	35.1	$ 199,457	$ 5,253	34.9	$ 183,543	$ 4,618	34.9	$ 161,257
Total Revenue	$ 5,717	35.1	$ 200,542	$ 5,285	34.9	$ 184,548	$ 4,647	34.9	$ 162,198

124.3 Please provide information on 2008, 2009 and 2010 actuals for Schedule 77, by completing the following for each utility:

	2008			**2009**			**2010**		
	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days
Total Expenses									
Total Expenses, Revised Rates									

Response:

As discussed in response to BCUC IR 1.124.1, only actuals at revised rates have been provided, certain information is not available for FEVI and FEW for 2008 and 2009, and 2010 results are not comparable to 2008 and 2009.

FEI - 124.3	2008			2009			2010		
($000s)									
	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days
Total Expenses									
Total Expenses, Revised Rates	$ 1,444,820	39.4	$ 56,927,325	$ 1,289,501	39.2	$ 50,563,876	$ 1,180,347	37.5	$ 44,286,600

FEVI - 124.3	2008			2009			2010		
($000s)									
	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days
Total Expenses									
Total Expenses, Revised Rates							$ 148,856	33.9	$ 5,050,082

FEW - 124.3	2008			2009			2010		
($000s)									
	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days
Total Expenses									
Total Expenses, Revised Rates							$ 10,764	36.6	$ 394,488

Fort Nelson - 124.3	2008			2009			2010		
($000s)									
	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days
Total Expenses									
Total Expenses, Revised Rates	$ 5,488	37.4	$ 205,140	$ 5,133	36.8	$ 188,932	$ 4,691	36.4	$ 170,874

125.0 Reference: Allowed Capital Structure and Return on Equity

Exhibit B-1, Application, Section 5.7.2, pp. 312-316; Section 7, Tabs 7.1-7.4,

Schedules 79-81

Long-term Debt and Unfunded Debt Allocation

125.1 Common Equity proportion is determined and approved by the Commission; however the allocation of the remaining 60% is not. Please provide support for how the capitalization amount was allocated between Long-term Debt and Unfunded Debt for 2009-2013 for each utility. Please also explain any differences in methodology for the allocation between Long-term Debt and Unfunded Debt.

Response:

The FEU do not target a specific allocation of long-term debt or unfunded debt. The allocation of debt funding between long-term and unfunded is influenced by working capital balances, capital expenditures, refinancing debt obligations upon prior debt obligations maturing and timing of long-term debt offerings. The unfunded debt balance can change over time as a result of the factors listed above and the utilization of the operating credit facilities. The FEU issue long-term debt from time to time as required and as reviewed and approved by the Commission.

In the determination of the revenue requirements the allocated portion of unfunded debt is the allowed debt portion of rate base (60 percent) less the average principal outstanding of long-term debt. The following table provides the allocation of long-term and unfunded debt for 2009-2013 for each utility:

Mainland, ($ Thousands)	**2009 Approved**		**2010 Approved**		**2011 Approved**		**2012 Forecast**		**2013 Forecast**	
	$	%	$	%	$	%	$	%	$	%
Total Rate Base	2,541,323		2,534,454		2,629,185		2,736,507		2,788,327	
Less: Allowed Equity Portion	(889,717)	35.01%	(1,013,782)	40.00%	(1,051,674)	40.00%	(1,094,603)	40.00%	(1,115,331)	40.00%
	1,651,606		1,520,672		1,577,511		1,641,904		1,672,996	
Less: Average Principal Outstanding LTD	(1,504,299)	59.19%	(1,483,848)	58.55%	(1,534,655)	58.37%	(1,582,117)	57.82%	(1,582,515)	56.76%
Allocated Short Term Debt	147,307	5.80%	36,824	1.45%	42,856	1.63%	59,787	2.18%	90,481	3.24%

Vancouver Island, ($ Thousands)	**2009 Approved**		**2010 Approved**		**2011 Approved**		**2012 Forecast**		**2013 Forecast**	
	$	%	$	%	$	%	$	%	$	%
Total Rate Base	539,845		553,966		728,993		787,864		814,078	
Less: Allowed Equity Portion	(215,938)	40.00%	(221,586)	40.00%	(291,597)	40.00%	(315,146)	40.00%	(325,631)	40.00%
	323,907		332,380		437,396		472,718		488,447	
Less: Average Principal Outstanding LTD	(260,940)	48.34%	(289,659)	52.29%	(390,740)	53.60%	(365,526)	46.39%	(350,000)	42.99%
Allocated Short Term Debt	62,967	11.66%	42,721	7.71%	46,656	6.40%	107,192	13.61%	138,447	17.01%

Whistler, ($ Thousands)	**2009 Approved**		**2010 Approved**		**2011 Approved**		**2012 Forecast**		**2013 Forecast**	
	$	%	$	%	$	%	$	%	$	%
Total Rate Base	38,816		42,568		42,594		42,139		41,502	
Less: Allowed Equity Portion	(15,526)	40.00%	(17,027)	40.00%	(17,038)	40.00%	(16,856)	40.00%	(16,601)	40.00%
	23,290		25,541		25,556		25,283		24,901	
Less: Average Principal Outstanding LTD	(14,049)	36.19%	(20,000)	46.98%	(20,000)	46.95%	(20,000)	47.46%	(20,000)	48.19%
Allocated Short Term Debt	9,241	23.81%	5,541	13.02%	5,556	13.05%	5,283	12.54%	4,901	11.81%

Fort Nelson, ($ Thousands)	2009 Approved		2010 Actual		2011 Approved		2012 Forecast		2013 Forecast	
	$	%	$	%	$	%	$	%	$	%
Total Rate Base	5,405		5,410		6,839		8,889		9,126	
Less: Allowed Equity Portion	(2,162)	40.00%	(2,164)	40.00%	(2,736)	40.00%	(3,556)	40.00%	(3,650)	40.00%
	3,243		3,246		4,103		5,333		5,476	
Less: Average Principal Outstanding LTD	(3,035)	56.15%	(2,942)	54.38%	(3,013)	44.06%	(5,094)	57.30%	(5,134)	56.25%
Allocated Short Term Debt	208	3.85%	304	5.62%	1,090	15.94%	240	2.70%	342	3.75%

126.0 Reference: Summary of Revenue Requirements and Summary of Rate Changes for 2012 and 2013

Exhibit B-1, Application, Section 3.3, pp. 47-68; Section 7, Tabs 7.1 – 7.4, Schedule 1

Support for Details of Rate Changes from 2012 to 2013

126.1 The net revenue deficiency (surplus) at the bottom of Schedule 1 for each of the utilities agrees to Schedules 2 and 3, however, these Schedules do not provide a detailed breakdown of where the rate changes arise from. Please provide support on the determination of the amount of the rate change relating to Volume/Revenue Related, O&M Changes, Depreciation & Removal Cost Provision, Amortization Expense, and Other. If these are brought forward from other Schedules within this RRA, please provide the cross-reference.

Response:

Please refer to the tables below which provide additional support on the determination of the summary of the rate change as well as cross-references to the supporting financial schedules.

Summary of Rate Change 2012

Attachment 126.1a

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
1	Volume/Revenue Related									
2	*Royalty Revenues*									
3	Royalty Credit 2012			$ -						Schedule 5
4	Approved Royalty Credit 2011			(40.1)						Schedule 4
5	Expiry of Royalty Credits				$ 40.1					= Line 3 - Line 4
6										
7	*Surplus embedded in Existing Rates*				(22.4)					Schedule 4
8										
9	*Customer Growth and Use Rates*									
10	Sales and Transportation Revenue 2012			(195.1)						Schedule 5
11	Approved Sales and Transportation Revenue 2011			(202.9)						Schedule 4
12	Change				7.8					= Line 10 - Line 11
13										
14	Gross Margin at existing rates 2012	$ (556.8)				$ (7,716.0)		$ (1,874.0)		Schedule 5
15	Approved Gross Margin 2011	(552.3)				(8,213.9)		(1,762.5)		Schedule 4
16	Change		$ (4.5)				$ 497.9		$ (111.5)	= Line 14 - Line 15
17										
18	*Change in Other Revenue*									
19	Other Operating Revenue 2012	(27.2)		(12.7)		(16.0)		(24.0)		Schedule 5
20	Approved Other Operating Revenue 2011	(24.4)		(9.8)		(56.4)		(59.5)		Schedule 4
21	Change		(2.8)		(2.9)		40.4		35.5	= Line 19 - Line 20
22										
23	FEVI Cost of Gas Changes									
24	*Cost of Gas*									
25	Cost of Gas 2012			74.3						Schedule 5
26	Approved Cost of Gas 2011			107.3						Schedule 4
27	Change				(33.0)					= Line 25 - Line 26
28										
29	*GCVA Additions*									
30	GCVA Amortization 2012			(8.1)						Schedule 5
31	Approved GCVA Amortization 2011			-						Schedule 4
32	Change				(8.1)					= Line 30 - Line 31
33										
34	O&M Changes									
35	*Gross O&M Increases*									
36	Total Gross O&M 2012	224.1		35.2		906.2		865.5		Schedule 23
37	Approved Total Gross O&M 2011	214.7		32.7		868.0		811.7		Schedule 23 (FEFN: Line 41 + 43)
38	Change		9.4		2.5		38.2		53.8	= Line 36 - Line 37
39										
40	*Less: Capitalized Overhead*									
41	Capitalized Overhead 2012	(31.4)		(4.9)		(126.9)		(121.2)		Schedule 23
42	Approved Capitalized Overhead 2011	(30.1)		(4.6)		(121.5)		(113.6)		Schedule 23
43	Change		(1.3)		(0.4)		(5.3)		(7.5)	= Line 41 - Line 42

Summary of Rate Change 2012

Attachment 126.1a

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
44										
45	Depreciation & Removal Cost Provision									
46	*Change in Depreciation Rates*		4.6		(0.3)		28.2		(30.0)	Tables 5.4-1, 5.4-2, 5.4-3, Page 284, 285, 286, Lines 72, 48, 21; (FEFN: p.284, Note 95)
47										
48	*Tax Expense Impact of Depreciation Changes*									
49	Change in Depreciation Rates	4.6		(0.3)		28.2		(30.0)		= Line 46
50	Depreciation from Net Additions	13.0		4.0		4.5		67.7		= Line 61
51	Removal Cost Provision	4.9		3.6		75.4		-		= Line 66
52	Total	22.4		7.2		108.1		37.7		= Line 49 + Line 50 + Line 51
53	Tax Rate 2012	25.0%		25.0%		25.0%		25.0%		Schedule 31
54	Tax Expense Impact of Depreciation Changes		7.5		2.4		36.0		12.6	= Line 52 / (1 - Line 53) * Line 53
55										
56	*Depreciation from Net Additions*									
57	Net Depreciation Expense 2012	118.1		34.0		425.0		355.0		Schedule 28
58	Approved Net Depreciation Expense 2011	100.5		30.4		392.3		317.3		Schedule 27
59	Change	17.5		3.6		32.7		37.7		= Line 57 - Line 58
60	Less: Change in Depreciation Rates	4.6		(0.3)		28.2		(30.0)		= Line 46
61	Depreciation from Net Additions		13.0		4.0		4.5		67.7	= Line 59 - Line 60
62										
63	*Removal Cost Provision*									
64	Removal Cost Provision 2012	16.2		3.9		80.0		-		Schedule 28
65	Approved Removal Cost Provision 2011	11.3		0.3		4.6		-		Schedule 27
66	Change		4.9		3.6		75.4		-	= Line 64 - Line 65
67										
68	Amortization Expense									
69	*CIAC*									
70	Amortization of CIAC 2012	(6.3)		(4.2)		(5.0)		-		Schedule 28
71	Approved Amortization of CIAC 2011	(6.7)		(4.4)		-		(28.9)		Schedule 27
72	Change		0.4		0.2		(5.0)		28.9	= Line 70 - Line 71
73										
74	*Deferral Accounts*									
75	Amortization of Deferred Charges 2012	5.9		2.1		562.0		5.0		Schedule 28
76	Approved Amortization of Deferred Charges 2011	(5.3)		(0.8)		940.0		71.3		Schedule 27
77	Change		11.2		2.9		(378.0)		(66.3)	= Line 75 - Line 76
78										
79	Other									
80	*Property and Other Taxes*									
81	Property and Sundry Taxes 2012	49.7		9.9		236.0		172.0		Schedule 5
82	Approved Property and Sundry Taxes 2011	50.2		9.6		278.4		165.2		Schedule 4
83	Change		(0.6)		0.3		(42.4)		6.8	= Line 81 - Line 82
84										
85	*Other (NSP Provision, Transportation Costs, VINGPA)*									
86	NSP Provision 2012	-		-		-		-		Schedule 5
87	Approved NSP Provision 2011	1.0		(1.4)		6.0		-		Schedule 4
88	Change	(1.0)		1.4		(6.0)		-		= Line 86 - Line 87
89										
90	Transportation Costs 2012			4.5		2,585.0		-		Schedule 5
91	Approved Transportation Costs 2011			4.1		2,458.0		-		Schedule 4
92	Change			0.4		127.0		-		= Line 90 - Line 91
93										
94	VINGPA Earnings Reduction 2012			-						Schedule 5
95	Approved VINGPA Earnings Reduction 2011			(1.9)						Schedule 4
96	Change			1.9						= Line 94 - Line 95
97	Total Other Change		(1.0)		3.6		121.0		-	= Line 88 + Line 92 + Line 96

Summary of Rate Change 2012

Attachment 126.1a

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
98										
99	*Income Tax Rate Change*									
100	Adjusted Taxable Income After Taxes 2012	73.4		11.6		1,009.0		169.0		Schedule 31
101	Approved Tax Rate 2011	26.5%		26.5%		26.5%		26.5%		Schedule 30
102	Income Taxes at Approved 2011 Tax Rate	26.5		4.2		363.8		60.9		= Line 100 / (1 - Line 101) * Line 101
103										
104	Income Taxes 2012	24.5		3.9		336.0		56.0		Schedule 5
105	Income Taxes at Approved 2011 Tax Rate	26.5		4.2		363.8		60.9		= Line 102
106	Change		(2.0)		(0.3)		(27.8)		(4.9)	= Line 104 - Line 105
107										
108	*Other Income Tax Changes*									
109	Adjustments to Taxable Income 2012	(30.6)		(19.9)		(677.0)		(169.0)		Schedule 34
110	Approved Adjustments to Taxable Income 2011	(9.7)		(17.2)		(504.7)		(36.6)		Schedule 33
111	Change	(20.8)		(2.7)		(172.3)		(132.4)		= Line 109 - Line 110
112	Approved Tax Rate 2011	26.5%		26.5%		26.5%		26.5%		Schedule 30
113	Adjustments to Taxable Income at 2011 Tax Rate	(7.5)		(1.0)		(62.1)		(47.7)		= Line 111 / (1 - Line 112) * Line 112
114	Rate Base Growth at 2011 Tax Rates	1.5		0.8		(6.6)		28.0		= Line 148 / (1 - Line 112) * Line 112
115	Approved VINGPA Earnings Reduction at 2011 Tax Rates			(0.7)						= Line 95 / (1 - Line 112) * Line 112
116	Tax Expense Impact of Depreciation Changes	7.5		2.4		36.0		12.6		= Line 54
117	Other Income Tax Changes		(13.5)		(1.9)		(104.7)		(32.3)	= Line 113 + Line 114 - Line 115 - Line 116
118										
119	*Financing Rate Changes*									
120	Earned Return 2012	212.2		57.1		2,906.0		688.0		Schedule 5
121	Approved Earned Return 2011	208.4		55.3		3,012.1		518.2		Schedule 4
122	Change	3.8		1.8		(106.1)		169.8		= Line 120 - Line 121
123	Long Term Debt Financing Changes	3.3		(1.5)		-		144.5		= Line 133
124	Short Term Debt Financing Changes	0.8		2.9		(14.1)		(38.3)		= Line 139
125	Rate Base Growth	4.1		2.4		(18.2)		77.9		= Line 148
126	Financing Rate Changes		(4.4)		(1.9)		(73.8)		(14.3)	= Line 122 - Line 123 - Line 124 - Line 125
127										
128	*Financing Changes*									
129	Long Term Debt 2012	1,582.1		365.5		20,000.0		5,093.7		Schedule 80
130	Approved Long Term Debt 2011	1,534.7		390.7		20,000.0		3,013.2		Schedule 82
131	Change	47.4		(25.2)		-		2,080.5		= Line 129 - Line 130
132	Approved Long Term Debt Rate 2011	6.94%		6.12%		5.11%		6.95%		Schedule 82
133	Long Term Debt Financing Changes	3.3		(1.5)		-		144.5		= Line 131 * Line 132
134										
135	Short Term Debt 2012	59.8		107.2		5,282.0		239.3		Schedule 80
136	Approved Short Term Debt 2011	42.8		46.7		5,556.4		1,090.4		2010/2011 Approved RRA
137	Change	16.9		60.5		(274.4)		(851.1)		= Line 135 - Line 136
138	Approved Short Term Debt Rate 2011	4.50%		4.75%		5.15%		4.50%		Schedule 79 (FEVI ref. 2010/2011 Approved RRA)
139	Short Term Debt Financing Changes	0.8		2.9		(14.1)		(38.3)		= Line 137 * Line 138
140	Financing Changes		4.1		1.3		(14.1)		106.2	= Line 133 + Line 139
141										
142	*Rate Base Growth*									
143	Utility Rate Base 2012	2,736.5		787.9		42,139.0		8,889.0		Schedule 5
144	Approved Utility Rate Base 2011	2,629.2		729.0		42,594.0		6,838.9		Schedule 4
145	Change	107.3		58.9		(455.0)		2,050.1		= Line 143 - Line 144
146	Approved Equity Thickness	40.0%		40.0%		40.0%		40.0%		Schedule 80
147	Approved Return on Equity	9.5%		10.0%		10.0%		9.5%		Schedule 80
148	Rate Base Growth		4.1		2.4		(18.2)		77.9	= Line 145 * Line 146 * Line 147
149										
150	**Revenue Deficiency (Surplus)**		**$ 29.0**		**$ 0.0**		**$ 172.3**		**$ 122.6**	Schedule 1

Summary of Rate Change 2013

Attachment 126.1b

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
1	Volume/Revenue Related									
2	*Customer Growth and Use Rates*									
3	Sales and Transportation Revenue 2013			$ (196.6)						Schedule 6
4	Sales and Transportation Revenue 2012			(195.1)						Schedule 5
5	Change				$ (1.6)					= Line 3 - Line 4
6										
7	Gross Margin at existing rates 2013	$ (558.4)				$ (7,639.0)		$ (1,901.0)		Schedule 6
8	Gross Margin at existing rates 2012	(556.8)				(7,716.0)		(1,874.0)		Schedule 5
9	Change		$ (1.6)				$ 77.0		$ (27.0)	= Line 7 - Line 8
10										
11	*Change in Other Revenue*									
12	Other Operating Revenue 2013	(28.9)		(12.7)		(16.0)		(24.0)		Schedule 6
13	Other Operating Revenue 2012	(27.2)		(12.7)		(16.0)		(24.0)		Schedule 5
14	Change		(1.7)		(0.0)		-		-	= Line 12 - Line 13
15										
16	FEVI Cost of Gas Changes									
17	*Cost of Gas*									
18	Cost of Gas 2013			76.4						Schedule 6
19	Cost of Gas 2012			74.3						Schedule 5
20	Change				2.1					= Line 18 - Line 19
21										
22	*GCVA Additions*									
23	GCVA Amortization 2013			-						Schedule 6
24	GCVA Amortization 2012			(8.1)						Schedule 5
25	Change				8.1					= Line 23 - Line 24
26										
27	O&M Changes									
28	*Gross O&M Increases*									
29	Total Gross O&M 2013	236.5		35.5		915.2		896.6		Schedule 23
30	Total Gross O&M 2012	224.1		35.2		906.2		865.5		Schedule 23 (FEFN: Line 41 + 43)
31	Change		12.4		0.2		8.9		31.1	= Line 29 - Line 30
32										
33	*Less: Capitalized Overhead*									
34	Capitalized Overhead 2013	(33.1)		(5.0)		(128.1)		(125.5)		Schedule 23
35	Capitalized Overhead 2012	(31.4)		(4.9)		(126.9)		(121.2)		Schedule 23
36	Change		(1.7)		(0.0)		(1.3)		(4.4)	= Line 34 - Line 35

Summary of Rate Change 2013

Attachment 126.1b

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
37										
38	Depreciation & Removal Cost Provision									
39	*Tax Expense Impact of Depreciation Changes*									
40	Removal Cost Provision	0.5		0.1		2.0		-		= Line 54
41	Depreciation from Net Additions	5.5		1.1		16.0		10.0		= Line 49
42	Total	6.0		1.3		18.0		10.0		= Line 40 + Line 41
43	Tax Rate 2013	25.0%		25.0%		25.0%		25.0%		Schedule 32
44	Tax Expense Impact of Depreciation Changes		2.0		0.4		6.0		3.3	= Line 42 / (1 - Line 43) * Line 43
45										
46	*Depreciation from Net Additions*									
47	Net Depreciation Expense 2013	123.5		35.2		441.0		365.0		Schedule 29
48	Net Depreciation Expense 2012	118.1		34.0		425.0		355.0		Schedule 28
49	Change		5.5		1.1		16.0		10.0	= Line 47 - Line 48
50										
51	*Removal Cost Provision*									
52	Removal Cost Provision 2013	16.7		4.0		82.0		-		Schedule 29
53	Removal Cost Provision 2012	16.2		3.9		80.0		-		Schedule 28
54	Change		0.5		0.1		2.0		-	= Line 52 - Line 53
55										
56	Amortization Expense									
57	*CIAC*									
58	Amortization of CIAC 2013	(6.2)		(4.2)		(5.0)		-		Schedule 29
59	Amortization of CIAC 2012	(6.3)		(4.2)		(5.0)		-		Schedule 28
60	Change		0.1		(0.0)		-		-	= Line 58 - Line 59
61										
62	*Deferral Accounts*									
63	Amortization of Deferred Charges 2013	18.2		2.3		1,143.0		5.0		Schedule 29
64	Amortization of Deferred Charges 2012	5.9		2.1		562.0		5.0		Schedule 28
65	Change		12.3		0.2		581.0		-	= Line 63 - Line 64
66										
67	Other									
68	*Property and Other Taxes*									
69	Property and Sundry Taxes 2013	51.2		10.3		244.0		178.0		Schedule 6
70	Property and Sundry Taxes 2012	49.7		9.9		236.0		172.0		Schedule 5
71	Change		1.6		0.4		8.0		6.0	= Line 69 - Line 70
72										
73	*Other (NSP Provision, Transportation Costs, VINGPA)*									
74	Transportation Costs 2013			4.5		2,585.0		-		Schedule 6
75	Transportation Costs 2012			4.5		2,585.0		-		Schedule 5
76	Change				0.0		-		-	= Line 74 - Line 75

Summary of Rate Change 2013

Attachment 126.1b

Line No.	Particulars	FEI $ Millions	FEI Revenue Deficiency (Surplus) Impact	FEVI $ Millions	FEVI Revenue Deficiency (Surplus) Impact	FEW $ Thousands	FEW Revenue Deficiency (Surplus) Impact	FEFN $ Thousands	FEFN Revenue Deficiency (Surplus) Impact	Cross Reference Schedule & Other
	Cross Reference Section & Tab:	Sect 7, Tab 7.1		Sect 7, Tab 7.2		Sect 7, Tab 7.3		Sect 7, Tab 7.4		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(4)
77										
78	*Income Tax Rate Change*									
79	Adjusted Taxable Income After Taxes 2013	90.5		22.3		1,626.0		165.0		Schedule 32
80	Tax Rate 2011	26.5%		26.5%		26.5%		26.5%		Schedule 30
81	Income Taxes at 2011 Tax Rate	32.6		8.0		586.2		59.5		= Line 79 / (1 - Line 80) * Line 80
82										
83	Income Taxes 2013	30.2		7.4		542.0		55.0		Schedule 6
84	Income Taxes at 2011 Tax Rate	32.6		8.0		586.2		59.5		= Line 81
85	Less: Tax Rate Impact from 2012 Summary	(2.0)		(0.3)		(27.8)		(4.9)		Attachment 126.1a, Line 106
86	Change		(0.5)		(0.3)		(16.5)		0.4	= Line 83 - Line 84 - Line 85
87										
88	*Other Income Tax Changes*									
89	Adjustments to Taxable Income 2013	(15.5)		(10.2)		(34.0)		(182.0)		Schedule 35
90	Adjustments to Taxable Income 2012	(30.6)		(19.9)		(677.0)		(169.0)		Schedule 34
91	Change	15.1		9.6		643.0		(13.0)		= Line 89 - Line 90
92	Tax Rate 2011	26.5%		26.5%		26.5%		26.5%		Schedule 30
93	Adjustments to Taxable Income at 2012 Tax Rate	5.4		3.5		231.8		(4.5)		= Line 91 / (1 - Line 92) * Line 92
94	Rate Base Growth at 2012 Tax Rates	0.7		0.4		(9.2)		3.0		= Line 127 / (1 - Line 92) * Line 92
95	Tax Expense Impact of Depreciation Changes	2.0		0.4		6.0		3.3		= Line 44
96	Other Income Tax Changes		4.1		3.4		216.6		(4.8)	= Line 93 + Line 94 - Line 95
97										
98	*Financing Rate Changes*									
99	Earned Return 2013	216.1		60.3		2,915.0		706.0		Schedule 6
100	Earned Return 2012	212.2		57.1		2,906.0		688.0		Schedule 5
101	Change	3.9		3.2		9.0		18.0		= Line 99 - Line 100
102	Long Term Debt Financing Changes	0.0		(0.9)		-		2.7		= Line 112
103	Short Term Debt Financing Changes	0.8		1.3		(14.6)		2.8		= Line 118
104	Rate Base Growth	2.0		1.0		(25.5)		9.0		= Line 127
105	Financing Rate Changes		1.1		1.8		49.1		3.5	= Line 101 - Line 102 - Line 103 - Line 104
106										
107	*Financing Changes*									
108	Long Term Debt 2013	1,582.5		350.0		20,000.0		5,133.5		Schedule 81
109	Long Term Debt 2012	1,582.1		365.5		20,000.0		5,093.7		Schedule 83
110	Change	0.4		(15.5)		-		39.8		= Line 108 - Line 109
111	Long Term Debt Rate 2012	6.73%		5.75%		5.11%		6.73%		Schedule 83
112	Long Term Debt Financing Changes	0.0		(0.9)		-		2.7		= Line 110 * Line 111
113										
114	Short Term Debt 2013	90.2		138.3		4,892.0		340.5		Schedule 81
115	Short Term Debt 2012	59.8		107.2		5,282.0		239.3		Schedule 80
116	Change	30.5		31.1		(390.0)		101.2		= Line 114 - Line 115
117	Short Term Debt Rate 2012	2.75%		4.25%		3.75%		2.75%		Schedule 80
118	Short Term Debt Financing Changes	0.8		1.3		(14.6)		2.8		= Line 116 * Line 117
119	Financing Changes		0.9		0.4		(14.6)		5.5	= Line 112 + Line 118
120										
121	*Rate Base Growth*									
122	Utility Rate Base 2013	2,788.3		814.1		41,502.0		9,126.0		Schedule 6
123	Utility Rate Base 2012	2,736.5		787.9		42,139.0		8,889.0		Schedule 5
124	Change	51.8		26.2		(637.0)		237.0		= Line 122 - Line 123
125	Approved Equity Thickness	40.0%		40.0%		40.0%		40.0%		Schedule 81
126	Approved Return on Equity	9.5%		10.0%		10.0%		9.5%		Schedule 81
127	Rate Base Growth		2.0		1.0		(25.5)		9.0	= Line 124 * Line 125 * Line 126
128										
129	**Revenue Deficiency (Surplus)**		**$ 36.8**		**$ 17.4**		**$ 906.9**		**$ 32.8**	Schedule 1

127.0 Reference: Adjustments to Taxable Income

Exhibit B-1, Application, Section 5.6, pp. 299-300; Section 7, Tabs 7.1 – 7.4,

Schedule 33-35

Most Recently Filed Tax Return for Comparison

127.1 If not all ready filed as part of the various annual reports, please provide a copy of your most recently filed corporate tax returns (i.e. 2009 and 2010) for each company, in particular Schedule 1 showing the adjustments to taxable income.

Response:

The FEU are providing copies of income tax returns to the Commission on a confidential basis under separate cover, consistent with prior practice.

Income tax returns for 2010 are in the process of being prepared and filed. Once these are finalized the Companies will also provide copies to the Commission on a confidential basis.

FEI (then TGI) provided a copy of its 2009 tax return to the Commission on November 10, 2010.

Confidential Attachment 127.1 contains copies of the FEVI (then TGVI) and FEW (then TGW) 2009 tax returns as well as FEW's amended 2009 tax return filed in December of 2010 to reflect adjustments arising from Commission Order No. G-138-10 in respect of conversion costs.

128.0 Reference: Operating and Maintenance Costs

Exhibit B-1, Tab 7.1, schedule 21

O&M

O& M typically includes costs that can be categorized as either 1) ongoing in nature or 2)one-time, unique costs for particular projects or activities.

128.1 For each of the Utilities, classify O&M costs for 2010, 2011, 2012 and 2013 into one of each of the expense types, recurring or one-time. These costs should be presented in tabular format which takes totals presented in the Application. Also provide the table in fully functional electronic format.

O&M Year- 2010

Cost type:	2010-recurring	2010-one-time	20010- total

Response:

The FEU do not track O&M expenses by recurring or one-time. Instead the O&M philosophy involves managing O&M to budget on a company-wide portfolio approach.

On a forecast basis, the FEU recognize and plan for the following:

- Cyclical expenses where the cycle of reoccurrence is greater than one year.
- Planned one-time expenses – occasionally these will be identified on a forecast basis in which case they will be forecast accordingly. In this Application (Exhibit B-1), each department has identified these 2012 and 2013 items in Section 5 in its "2012 and 2013 Forecast" discussion.
- Unforeseen expenses – by definition these are very difficult to forecast and are only identified with the benefit of hindsight. In the Application, each department has identified material items in Section 5 in its "2010 and 2011 Review" discussion.

In terms of managing actual O&M, management meets regularly to review the ongoing and emerging operational needs of the organization and considers the prioritization of such needs and deployment of resources to ensure that the Companies' operations are conducted in a safe and reliable manner. Depending on the circumstances, to accommodate unusual or unforeseen items, the O&M could be shifted between the various projects/initiatives as well as between the departments. The result of this is that management seeks to capitalize on "one-time" savings or opportunities so that "one-time" initiatives can be pursued. This approach has proven to be effective and has allowed the FEU to effectively meet customer needs in a cost-efficient manner.

Although the FEU do not track O&M by the categories of recurring and one-time, in reviewing the Application, the FEU note the following items that have been identified as unusual in the 2010-2012 period and are in excess of $500 thousand, and that we believe would qualify as "one time".

- Executive retirements $2.59 million
- Rebranding costs $2.68 million
- 2010-2011 Shared Services true up ($0.62) million in FEI offset by the same amount in FEVI

In 2010 FEI realized lower costs as a result of the delayed hiring that occurred throughout the various departments, and also lower bad debt expense. These two items largely offset the one-time costs related to executive retirements and rebranding that occurred in 2010 and 2011.

128.2 Please amend schedule 21 to including the 2010 approved amounts in column 1 of this schedule.

Response:

The following is Schedule 21 revised to include 2010 Approved amounts.

- Sect 7-TAB 7.1, Schedule 21

FORTISBC ENERGY INC. - Mainland

Section 7
TAB 7.1
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.	Particulars	2010 APPROVED	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	M&E Costs	$ 45,497	$ 43,296	$ 48,663	$ 48,125	$ 55,081	$ 57,205	
2	COPE Costs	29,505	28,413	31,938	31,054	35,953	37,944	
3	COPE Customer Services Costs		-	-	-	11,788	11,144	
4	IBEW Costs	24,870	22,625	26,559	25,532	26,867	28,234	
5								
6	**Labour Costs**	**99,872**	**94,334**	**107,160**	**104,712**	**129,689**	**134,526**	
7								
8	Vehicle Costs	3,111	3,625	3,084	3,280	3,632	3,685	
9	Employee Expenses	5,212	5,805	5,227	4,035	5,553	5,716	
10	Materials and Supplies	7,251	6,738	7,191	5,494	6,981	7,347	
11	Computer Costs	11,192	10,214	11,991	10,856	14,489	15,077	
12	Fees and Administration Costs *	27,860	29,309	28,512	27,858	59,202	64,499	
13	Contractor Costs *	60,110	62,151	60,052	61,910	16,129	17,873	
14	Facilities	13,973	13,023	14,318	12,984	15,827	14,573	
15	Recoveries & Revenue	(22,117)	(18,680)	(22,854)	(17,094)	(27,383)	(26,824)	
16								
17	**Non-Labour Costs**	**106,592**	**112,185**	**107,520**	**109,323**	**94,430**	**101,945**	
18								
19								
20	**Total Gross O&M Expenses**	**206,464**	**206,519**	**214,680**	**214,035**	**224,119**	**236,472**	
21								
22	Add: PST Savings		-	-	645	(0)	(0)	
23	Less: Capitalized Overhead	(28,905)	(28,905)	(30,055)	(30,055)	(31,377)	(33,106)	
24								- Sect 7-TAB 7.1, Schedule 4
25	**Total O&M Expenses**	**$ 177,559**	**$ 177,614**	**$ 184,625**	**$ 184,625**	**$ 192,742**	**$ 203,365**	- Sect 7-TAB 7.1, Schedule 5
26	* Note: 2012 & 2013 reflect customer service costs previously contracted							- Sect 7-TAB 7.1, Schedule 6
27	* Note: Shared Services fees incurred are included on line 12 Fees and Administration Costs while Shared Services recoveries are shown on line 15 Recoveries & Revenue.							

- Sect 7-TAB 7.2, Schedule 21

FORTISBC ENERGY (Vancouver Island) INC.

Section 7
TAB 7.2
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.	Particulars	2010 APPROVED	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	M&E Costs	$ 4,225	$ 3,570	$ 3,868	$ 4,034	$ 3,305	$ 3,307	
2	COPE Costs	109	248	110	115	105	109	
3	IBEW Costs	4,486	4,644	5,451	4,862	5,796	6,199	
4								
5	**Labour Costs**	**8,819**	**8,462**	**9,429**	**9,011**	**9,207**	**9,615**	
6								
7	Vehicle Costs	667	606	722	672	778	786	
8	Employee Expenses	567	568	587	628	596	611	
9	Materials and Supplies	1,341	1,122	1,395	1,073	1,090	1,099	
10	Computer Costs	302	529	231	234	198	181	
11	Fees and Administration Costs [1]	11,387	11,465	11,911	12,145	14,507	14,556	
12	Contractor Costs [1]	7,074	6,205	7,125	7,480	7,588	8,294	
13	Facilities	2,166	2,047	2,416	2,446	2,565	1,654	
14	Recoveries & Revenue	(1,093)	(1,153)	(1,115)	(1,071)	(1,293)	(1,314)	
15								
16	**Non-Labour Costs**	**22,410**	**21,390**	**23,273**	**23,606**	**26,030**	**25,867**	
17								
18								
19	**Total Gross O&M Expenses**	**31,229**	**29,852**	**32,702**	**32,617**	**35,236**	**35,482**	
20								
21	Add: PST Savings		0	0	85	0	(0)	
22	Less: O&M Difference from Allowed		1,379	0	0	0	0	
23	Less: Capitalized Overhead	(4,372)	(4,372)	(4,567)	(4,566)	(4,933)	(4,968)	
24								- Sect 7-TAB 7.2, Schedule 4
25	**Total O&M Expenses**	**$ 26,857**	**$ 26,859**	**$ 28,136**	**$ 28,136**	**$ 30,303**	**$ 30,515**	- Sect 7-TAB 7.2, Schedule 5
26	[1] 2012 and 2013 reflect customer service costs previously contracted							- Sect 7-TAB 7.2, Schedule 6
27	* Note: Shared Services fees incurred are included on line 12 Fees and Administration Costs while Shared Services recoveries are shown on line 15 Recoveries & Revenue.							

- Sect 7-TAB 7.3, Schedule 21

FORTISBC ENERGY (Whistler) INC.

Section 7
TAB 7.3
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.	Particulars	2010 APPROVED	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	M&E Costs	$ 84	$ 59	$ 86	$ 15	$ 14	$ 14	
2	COPE Costs	-	1	-	-	-	-	
3	IBEW Costs	172	212	172	187	227	221	
4								
5	**Labour Costs**	**256**	**272**	**257**	**202**	**240**	**235**	
6								
7	Vehicle Costs	40	28	41	32	25	24	
8	Employee Expenses	14	(17)	14	9	4	5	
9	Materials and Supplies	14	21	14	12	31	30	
10	Computer Costs	1	1	1	0	3	4	
11	Fees and Administration Costs [1]	320	289	331	320	381	383	
12	Contractor Costs [1]	153	133	158	240	160	173	
13	Facilities	59	59	60	72	74	75	
14	Recoveries & Revenue	(8)	(14)	(9)	(20)	(13)	(14)	
15								
16	**Non-Labour Costs**	**593**	**501**	**350**	**667**	**666**	**680**	
17								
18								
19	**Total Gross O&M Expenses**	**849**	**773**	**607**	**868**	**906**	**915**	
20								
21	Add: PST Savings		0	0	(0)	0	(0)	
22	Less: Capitalized Overhead	(119)	(119)	(122)	(122)	(127)	(128)	
23								- Sect 7-TAB 7.3, Schedule 4
24	**Total O&M Expenses**	**$ 730**	**$ 654**	**$ 747**	**$ 747**	**$ 779**	**$ 787**	- Sect 7-TAB 7.3, Schedule 5
25	[1] 2012 and 2013 reflect customer service costs previously contracted							
26	* Note: Shared Services fees incurred are included on line 12 Fees and Administration Costs while Shared Services recoveries are shown on line 15 Recoveries & Revenue.							

- Sect 7-TAB 7.4, Schedule 21

FORTISBC ENERGY INC. - Fort Nelson

Section 7
TAB 7.4
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.	Particulars	2010 APPROVED	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	M&E Costs	$ 138	$ 126	$ 141	$ 141	$ 167	$ 171	
2	COPE Costs	63	55	68	68	75	79	
3	COPE Customer Services Costs		-	-	-	35	34	
4	IBEW Costs	255	267	258	258	269	276	
5								
6	**Labour Costs**	**456**	**448**	**467**	**467**	**547**	**558**	
7								
8	Vehicle Costs	54	52	61	61	49	50	
9	Employee Expenses	37	19	17	17	19	20	
10	Materials and Supplies	27	16	14	14	15	15	
11	Computer Costs	34	29	34	34	42	44	
12	Fees and Administration Costs *	58	68	60	60	175	190	
13	Contractor Costs *	173	172	177	177	43	46	
14	Facilities	36	35	42	42	45	41	
15	Recoveries & Revenue	(61)	(45)	(56)	(58)	(70)	(68)	
16								
17	**Non-Labour Costs**	**358**	**346**	**348**	**346**	**318**	**338**	
18								
19								
20	**Total Gross O&M Expenses**	**814**	**794**	**815**	**812**	**865**	**897**	
21								
22	Add: PST Savings		0	(3)	(0)	0	(0)	
23	Less: Capitalized Overhead	(114)	(114)	(114)	(114)	(121)	(126)	
24								- Sect 7-TAB 7.4, Schedule 4
25	**Total O&M Expenses**	**$ 700**	**$ 680**	**$ 698**	**$ 699**	**$ 744**	**$ 771**	- Sect 7-TAB 7.4, Schedule 5
26	* Note: 2012 & 2013 reflect customer service costs previously contracted							- Sect 7-TAB 7.4, Schedule 6
27	* Note: Shared Services fees incurred are included on line 12 Fees and Administration Costs while Shared Services recoveries are shown on line 15 Recoveries & Revenue.							

- Sect 7-TAB 7.5, Schedule 21

FortisBC Energy Utilities

Section 7
TAB 7.5
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2013
($000)

Line No.	Particulars	2010 APPROVED	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	M&E Costs	$ 49,943	$ 47,051	$ 52,758	$ 52,316	$ 58,567	$ 60,697	
2	COPE Costs	29,677	28,717	32,116	31,237	36,133	38,131	
3	COPE Customer Services Costs	-	-	-	-	11,824	11,177	
4	IBEW Costs	29,784	27,748	32,439	30,839	33,159	34,931	
5								
6	**Labour Costs**	**109,404**	**103,516**	**117,314**	**114,391**	**139,683**	**144,935**	
7								
8	Vehicle Costs	3,870	4,312	3,907	4,045	4,484	4,544	
9	Employee Expenses	5,830	6,375	5,845	4,688	6,172	6,351	
10	Materials and Supplies	8,632	7,897	8,614	6,593	8,117	8,490	
11	Computer Costs	11,529	10,773	12,256	11,124	14,734	15,306	
12	Fees and Administration Costs *	39,626	41,131	40,815	40,383	74,264	79,629	
13	Contractor Costs *	67,510	68,661	67,512	69,807	23,920	26,386	
14	Facilities	16,234	15,164	16,836	15,544	18,511	16,344	
15	Recoveries & Revenue	(23,279)	(19,892)	(24,034)	(18,244)	(28,758)	(28,220)	
16								
17	**Non-Labour Costs**	**129,952**	**134,422**	**131,751**	**133,942**	**121,444**	**128,831**	
18								
19								
20	**Total Gross O&M Expenses**	**239,356**	**237,938**	**249,065**	**248,333**	**261,127**	**273,766**	
21								
22	Add: PST Savings		-	(3)	730	(0)	(0)	
23	Less: O&M Difference from Allowed	-	1,379	-	-	-	-	
24	Less: Capitalized Overhead	(33,510)	(33,510)	(34,857)	(34,857)	(36,558)	(38,327)	
25								- Sect 7-TAB 7.5, Schedule 4
26	**Total O&M Expenses**	**$ 205,846**	**$ 205,807**	**$ 214,205**	**$ 214,206**	**$ 224,569**	**$ 235,438**	- Sect 7-TAB 7.5, Schedule 5
27	* Note: 2012 & 2013 reflect customer service costs previously contracted							- Sect 7-TAB 7.5, Schedule 6
28	* Note: Shared Services fees incurred are included on line 12 Fees and Administration Costs while Shared Services recoveries are shown on line 15 Recoveries & Revenue.							

129.0 Reference: Long Term Asset Planning and Capital Expenditures

Exhibit B-1, Application, Section 1.2.4.3, p. 17; Section 6.2, p. 331 and Section 8, p. 768

Requested Approval of Forecasted Capital Expenditures for Mainland, FEW and Fort Nelson

Section 8, Requested Approvals, include requests for approval for forecasted capital expenditures for 2012 and 2013 for FEVI, as described in Section 6.2 of the RRA. However, per Section 1.2.4.3 – Long Term Asset Planning on p. 19 and Section 6.2 – Capital Expenditures on p. 343, the FEU is seeking approval for capital expenditures described within Section 6.2 of the RRA, including sustainment capital spending for a total of $82.2M in 2012 and $89.6M in 2013 for all areas.

The Section 8.1.2 2012 Rate Approvals for FEI references "Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEI for all non-bypass customers effective January 1, 2012, to recover the revenue requirements as described in Section 3.3.1 of the Application." Section 3.3.1 references, among others, the costs of depreciation and equity, both based on the rate base described in Section 6.

The Special Direction section 2.10(a) contains "… shall be regulated on a forecast test year basis and shall be required to apply to the BCUC for approval of its: (i) cost of service for each year and in conjunction therewith the BCUC shall determine the allowable capital additions to be made during such year …".

129.1 It would appear that Section 8 includes the request for approval of capital expenditures for FEVI only because of the Special Direction. Please confirm the FEU is requesting approval of capital expenditures in Section 6.2 of this RRA for the other utilities, FEI-Mainland, FEW and Fort Nelson, as well.

Response:

The capital expenditures described in Section 6.2 of the Application (Exhibit B-1) and specifically shown in Tables 6.2-1 to 6.2-4 for the Mainland, Vancouver Island, Whistler, and Fort Nelson service areas, respectively, will become part of the rate base, which is a component in the calculation of the rates for each service area. The rates for which the Companies are seeking approval thus incorporate the capital expenditures for FEI, FEVI, FEW, and Fort Nelson. Similarly, the rates incorporate the forecast O&M expenditures.

As reflected in the cited paragraph in the preamble, FEVI is seeking approval of the capital expenditures schedule due to the requirement of section 2.10(a) of the Special Direction.

However, the Companies are not specifically seeking acceptance of capital expenditures schedules for FEI, FEVI, and FEW under section 44.2 of the *UCA.*

130.0 Reference: Orders Sought

Exhibit B-1, Application, Part 8.1, p. 821

Approvals

130.1 Please provide a draft order for approval of the Application. Ensure all requested approvals include a reference to the Section of the Utilities Commission Act which empowers the Commission to grant such an approval.

Response:

Please refer to Attachment 130.1, which contains a draft form of order for the approvals sought in the Application including references to the appropriate section of the *Utilities Commission Act*. The draft form of order includes revisions to the requests under deferral accounts which reflect changes as a result of the responses to BCUC IR No. 1.

As noted in a number of the IR responses, the FEU will be filing an Evidentiary Update and expect to do so prior to July 21, 2011, the due date for the filing of IRs No. 2. The draft form of order in Attachment 130.1 does not include rate requests at this time. The Evidentiary Update will include corrections to items identified during the course of responding to IRs No. 1. In addition, there are currently a number of completed regulatory processes awaiting the receipt of Commission decisions. Should the FEU receive any of the pending Commission decisions and should those determinations have an effect on or impact the Application, resulting changes will be incorporated in the Evidentiary Update to the extent possible. The Evidentiary Update will include a draft form of final order and rate relief sought.

130.2 Under which sections of the Utilities Commission Act (UCA) are the Companies seeking approval of the following items:

"20. Approval of a deferral account to capture the costs and savings related to the amalgamation that vary from the forecast of zero for 2013. The approval of this deferral account does not in any way pre-determine the merits of any future application by the FEU to address amalgamation and harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

21. *Approval to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09, to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011 as described in Section 5.7 of the Application."*

Response:

The Companies clarify that, pursuant to sections 59 to 61 of the *UCA*, each of FEI, FEVI and FEW is seeking approval for a deferral account as specified in item 20. The deferral account specified in item 20 is approved on the same basis as other deferral accounts. It will be used by each utility to track the costs and savings of amalgamation up to the time of amalgamation. The establishment and approval of these deferral accounts does not pre-determine the appropriateness of amalgamation of FEI, FEVI, and FEW.

The Companies are seeking approval of item 21 pursuant to section 99 of the *UCA*. Given the pending amalgamation application, the timing of which was not known at the time Order No. G-158-09 was decided, it is more efficient to defer the filing of the evidence with respect to FEVI and FEW's equity component.

131.0 Reference: Organization Performance

TGVI Regional Facility Report in compliance with Commission Order No. C-1-11 (TGVI Regional Facility Compliance Report,) Appendices A&B

Operating Costs

131.1 Please update the TGVI Regional Facility Compliance Report appendices A and B to include the offices in the Mainland. Also provide the tables in fully functional electronic format.

Response:

Attachment 131.1a contains a fully functional Excel spreadsheet summarizing the Lower Mainland offices/musters data as provided for FEVI and Interior locations in Appendix A in the TGVI Regional Facility Compliance Report referenced above.

The "offices" in the Lower Mainland consist of two types: the primary office facility in Surrey and muster locations in various other Lower Mainland locations. There are no offices in the Lower Mainland which would have a comparable structure to an Interior regional office. With the exception of Surrey and Burnaby, the Lower Mainland locations are primarily field employee muster locations.

Attachment 131.1b contains a fully functional Excel spreadsheet summarizing the TGVI (FEVI) Regional Facility Compliance Report Appendix B to include the offices in the Lower Mainland.

The Planning group is primarily centralized in Surrey but do have some decentralized employees in the Interior, Lower Mainland and on the Island. Planners located in Surrey however are also assigned work activities and projects in all areas of the Province.

The field employees in the Lower Mainland are not confined to work activities within municipal boundaries. Although dispatch areas are established, flexibility is required to ensure available resources are dispatched to respond to emergencies and resources are assigned to where the work activities are located. For example, employees located in the Richmond muster, in addition to Richmond are generally responsible for activity in south Vancouver; employees located in the large Burnaby muster are responsible for East Vancouver, Burnaby, New Westminster and other municipalities. There is considerable migration of employees within the Lower Mainland which is comprised of two zones: the Metro Vancouver zone (west of the Fraser and Pitt Rivers) and Fraser Valley zone (east of the Fraser and Pitt Rivers).

The density of customers within the Lower Mainland contributes significantly to the generally higher operational metrics observed particularly for customer service technicians. The customer and activity totals on the spreadsheet do not include satellite towns such as Quesnel, Williams Lake, Ft. Nelson, Cache Creek, etc. which are not serviced specifically from the Interior Regional Offices.

Not included in the headcount totals are contractor resources which are headquartered out of contractor owned musters. In the Lower Mainland in particular there is substantial use of contractors for activities such as: leak survey, residential disconnects and capital work including mains and service additions and regulator replacements. With respect to mains and services work, the contractor has consistently deployed 11 crews.

132.0 Reference: Appendices

Exhibit B-1, Application, Appendix D

Historical Realized rate of return

132.1 Please complete the tables below:

Actual Rate of Return (%)	**2007**	**2008**	**2009**	**2010**	**2011 (projected)**
FEI					
FEVI					
FEW					
FEI-Fort Nelson					

Approved Rate of Return (%)	**2007**	**2008**	**2009**	**2010**	**2011**
FEI					
FEVI					
FEW					
FEI-Fort Nelson					

Response:

For the response to this question, FEI interprets "rate of return" to mean the return on equity.

The following tables have been updated to reflect the achieved and approved return on equity for 2007-2010 and the projected and approved return on equity for 2011. The achieved rate of return in FEI for 2007-2009 includes the 50 percent earnings sharing associated with the PBR each year, the achieved rate of return in FEVI for 2007-2011 is net of the VINGPA earnings reduction of $1.9 million and the achieved rate of return in FEW for 2007-2009 reflects the impact of the Deferred ROE Variance Account which served to true-up equity return to the approved amount in each year.

Actual Rate of Return (%)	2007	2008	2009	2010	2011 Projected
FEI[22]	9.55	9.63	10.44	9.42	10.00
FEVI[23]	8.09	8.41	8.71	9.15	9.36
FEW	8.97	9.22	9.49	9.50	8.51
Fort Nelson	5.80	12.25	13.77	7.05	7.58
Approved Rate of Return (%)	**2007**	**2008**	**2009**	**2010**	**2011**
FEI	8.37	8.62	8.99	9.50	9.50
FEVI	9.07	9.32	9.59	10.00	10.00
FEW	8.97	9.22	9.49	10.00	10.00
Fort Nelson	8.37	8.62	8.99	9.50	9.50

[22] FEI actual rate of return is after earnings sharing results for 2007-2009. The earnings sharing mechanism allowed for a 50:50 sharing between customers and the Company in earnings above and below the allowed ROE, beginning in 2004

[23] FEVI actual rate of return is after the VINGPA earnings reduction for 2007-2011. Column 5, Line 14 of Schedule 79 in Section 7.2 of 10.00% reflects the return on equity before the VINGPA earnings reduction of $1.867 million

133.0 Reference: Appendices

Exhibit B-1, Application, Appendix D-1 Historic Data, p. 1

O&M Resource costs – Separating Customer Service

The in-sourcing of the Customer Service functions has resulted in a significant shift of costs for 2012 and 2013 making comparisons to the prior years much more difficult.

Table D-1 contains the historical O&M by resource for Actual 2006 through Forecast 2013 for the combined companies.

133.1 Please provide three working spreadsheets, for Actual 2006 through Forecast 2013, of O&M by resource code for the combined companies: one of the total consolidation (Schedule in D-1), one with the consolidation of all groups except for Customer Services, and one for just Customer Services.

Response:

The requested working spreadsheets are provided in Attachment 133.1.

134.0 Reference: Appendices

Exhibit B-1, Application, Appendix D-4 Historic FTE

Full Time Equivalent (FTE)

The FTE data in Appendix B-3 provides 1,186 FTE for 2006 and 1,271 FTE for 2010 using the data presented for FEI and FEVI and adding 2 FTE for FEW and 3 FTE for Fort Nelson.

Table D-4 shows 1,187 FTE for 2006 and 1,347 FTE for 2010.

Table D-4 also shows the FTE for 2011 through 2013 as impacted by the Customer Service in-sourcing.

134.1 Please explain the differences between the FTE data in B-3 and D-1/D-4.

Response:

The FTE data in Appendix B-3 and Table D-1/D-4 of the Application (Exhibit B-1) both represent average full time equivalent. There are errors in the FTE data for 2006, 2009 and 2010 in Appendix B-3 as explained in the table below:

Actual Average Full Time Equivalent	2006	2007	2008	2009	2010
Mainland	1,059	1,084	1,124	1,165	1,241
Vancouver Island	122	102	97	97	101
Whistler	2	2	2	2	2
Fort Nelson	3	3	3	3	3
Total FTE per Appendix D1-D4	1,186	1,191	1,226	1,267	1,347
FEI (includes Ft. Nelson for 2006-2008)	1,062	1,087	1,127	1,241	1,165
FEVI	119	102	97	97	101
Total FTE per Appendix B-3	1,181	1,189	1,224	1,338	1,266
Add: FEW	2	2	2	2	2
Add: Ft. Nelson				3	3
Total FTE	1,183	1,191	1,226	1,343	1,271
FTE Difference	3 [1]	-	-	(76) [2]	76 [2]

Note 1: Appendix B-3 understated the 2006 Vancouver Island FTE by 3 and is the cause of the variance with Appendix B-3. The correct 2006 FTE figure for FEVI is 122 as reported in Appendix D1-D4.

Note 2: The variance of 76 FTE in 2009 and 2010 was due to a transposition error between 2009 and 2010 in the Mainland FTE in Appendix B-3. The correct FTE figure for FEI is 1,165 in 2009 and 1,241 in 2010, as reported in Appendix D1-D4.

134.2 Please confirm whether the Human Resources and Information Technology staff supporting Customer Service are included under Customer Service or included in their namesake groups.

Response:

The FEU confirm that Human Resources and Information Technology employees supporting Customer Service are included under Customer Service in Table D-4.

The following table illustrates the number of employees in Human Resources and Information Technology supporting Customer Service that are included under Customer Service for 2011 through 2013.

	Projected 2011	Forecast 2012	Forecast 2013
Human Resources	5	5	4
Information Technology	11	11	11
Total	16	16	15

135.0 Reference: Historic Summaries

Exhibit B-1, Application, Appendix D-5

Rate Increase

135.1 Please complete the Rate Increase table below for FEI, FEVI, FEW and Fort Nelson for 2006-2010. Also graph each table with the year on the X-axis and rate increase/O&M increase/inflation rate/customer growth percentage on the y-axis. Also provide the tables graphs in fully functional electronic format.

Rate Increase (all in %)

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2012 Forecast
Rate Increase								
Total O&M Increase								
Approved CPI (BC)								
Customer Growth rate								

Response:

Please find below the completed tables for each utility as well as the corresponding line graphs. The rates below are representative of the approximate annual change in burner tip rates for Residential customers in each utility. In addition to the categories requested, the FEU have also plotted the effective burner tip rate on an additional y-axis to provide context for the rate changes.

Please refer to Attachment 135.1 for the tables and graphs in fully functional electronic format.

Mainland

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Effective Burner Tip Rate Change	2.38%	-2.88%	8.92%	-16.03%	0.64%	-7.64%	2.66%	2.98%
Effective Burner Tip Rate ($/GJ)	$ 12.863	$ 12.493	$ 13.607	$ 11.425	$ 11.499	$ 10.620	$ 10.903	$ 11.228
Gross O&M Change (%)	3.33%	1.29%	0.29%	1.97%	1.60%	3.98%	4.40%	5.51%
Approved CPI (BC)	2.20%	2.00%	2.10%	2.10%	1.90%	2.10%	2.00%	2.00%
Avg Customer Growth	1.60%	1.68%	1.53%	1.01%	0.68%	0.68%	0.86%	0.79%

Vancouver Island

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Effective Burner Tip Rate Change	0.07%	3.15%	2.98%	0.84%	0.00%	0.00%	0.00%	0.00%
Effective Burner Tip Rate ($/GJ)	$ 15.380	$ 15.865	$ 16.338	$ 16.475	$ 16.475	$ 16.475	$ 16.475	$ 16.475
Gross O&M Change (%)	-10.04%	3.05%	2.00%	1.97%	-0.72%	4.71%	7.75%	0.70%
Approved CPI (BC)	2.20%	2.00%	2.10%	2.10%	1.90%	2.10%	2.00%	2.00%
Avg Customer Growth	4.75%	4.74%	3.91%	6.30%	2.41%	2.43%	0.48%	2.51%

Whistler

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Effective Burner Tip Rate Change	13.73%	-2.50%	24.76%	-8.12%	-20.94%	-8.94%	10.49%	7.12%
Effective Burner Tip Rate ($/GJ)	$ 20.276	$ 19.770	$ 24.666	$ 22.662	$ 17.916	$ 16.315	$ 18.027	$ 19.310
Gross O&M Change (%)	-3.61%	-5.73%	19.22%	-14.30%	4.77%	1.51%	49.26%	0.99%
Approved CPI (BC)	2.20%	2.00%	2.10%	2.10%	1.90%	2.10%	2.00%	2.00%
Avg Customer Growth	0.83%	0.97%	1.82%	1.52%	4.37%	1.42%	-0.23%	0.73%

Fort Nelson

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Effective Burner Tip Rate Change	7.93%	-4.16%	22.40%	-11.88%	-6.01%	-6.42%	1.79%	0.61%
Effective Burner Tip Rate ($/GJ)	$ 8.650	$ 8.290	$ 10.147	$ 8.941	$ 8.403	$ 7.864	$ 8.004	$ 8.053
Gross O&M Change (%)	6.63%	1.83%	-7.07%	1.80%	0.51%	2.64%	6.13%	3.70%
Approved CPI (BC)	2.20%	2.00%	2.10%	2.10%	1.90%	2.10%	2.00%	2.00%
Avg Customer Growth	1.09%	0.65%	0.04%	0.64%	0.38%	0.51%	1.18%	0.91%

Notes:

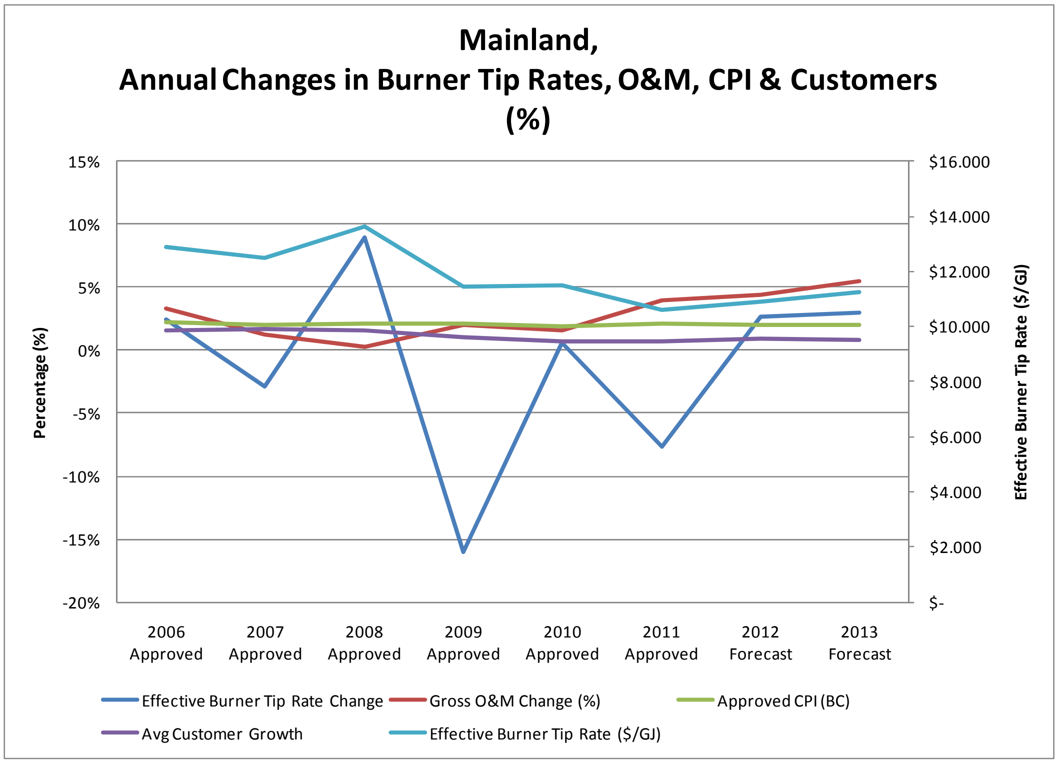
All Utilities: Change in Effective Rate is from Approved prior year rate and represents Residential rates;

FEI: 2006-2009, gross O&M changed in accordance with the terms of the PBR

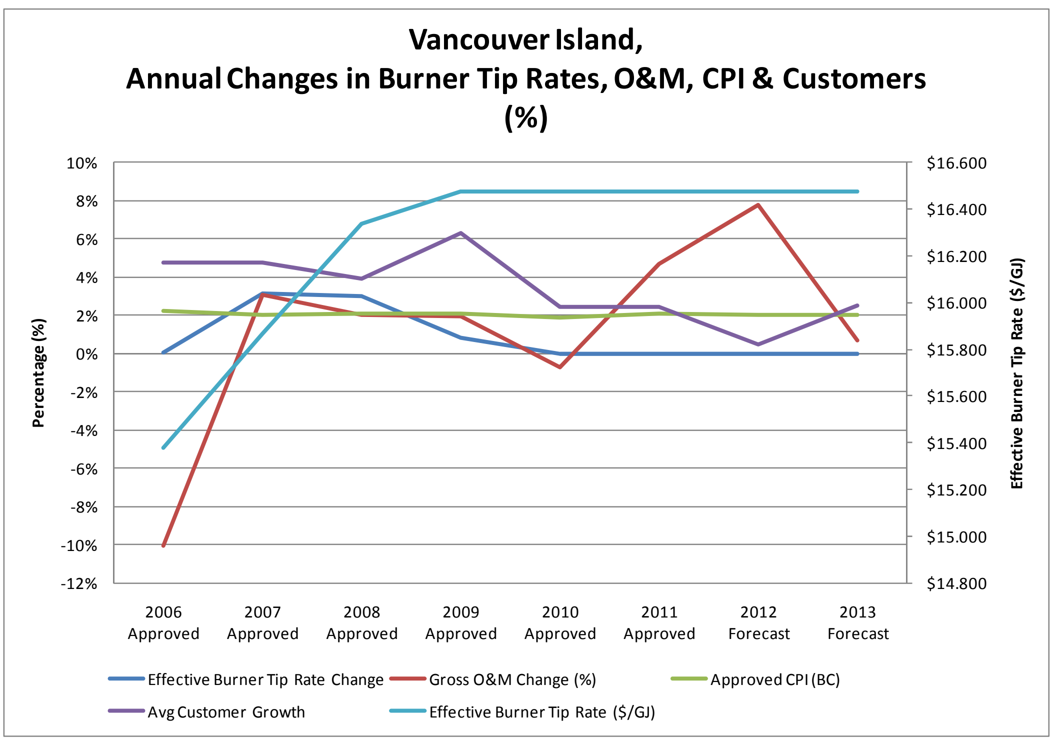
FEVI: Rate Freeze for 2010-2013

FEW: No Approved O&M & Avg Customer for 2006 & 2007, therefore applied Actuals;

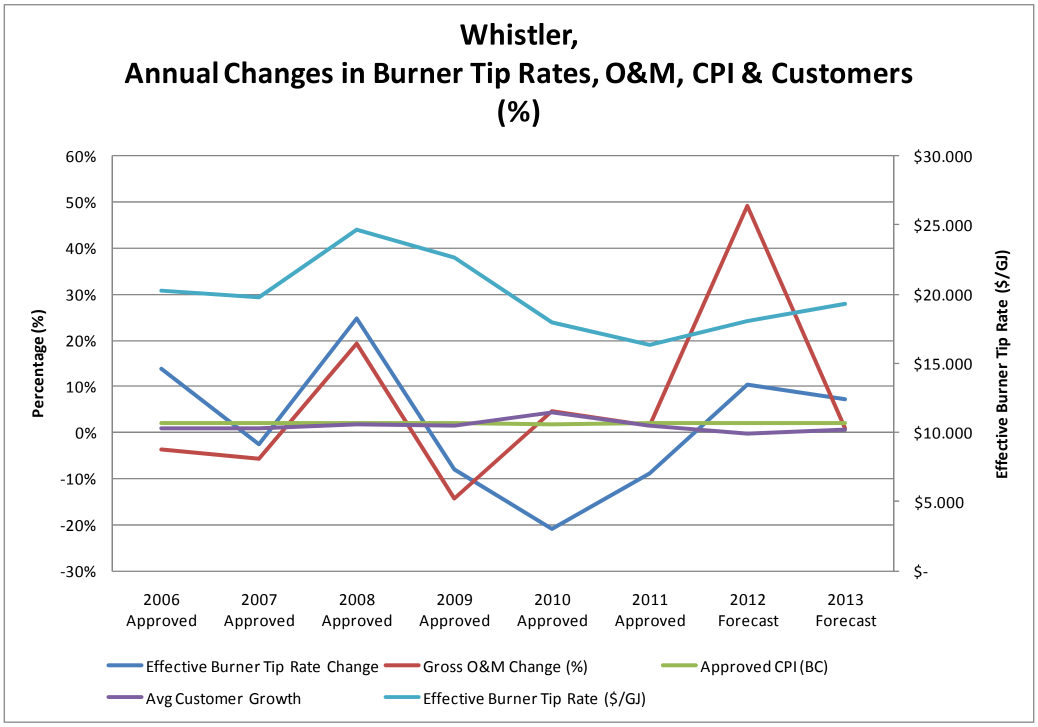
Fort Nelson: No Approved O&M & Avg Customer for 2006, 2007 and 2010, therefore applied Actuals;



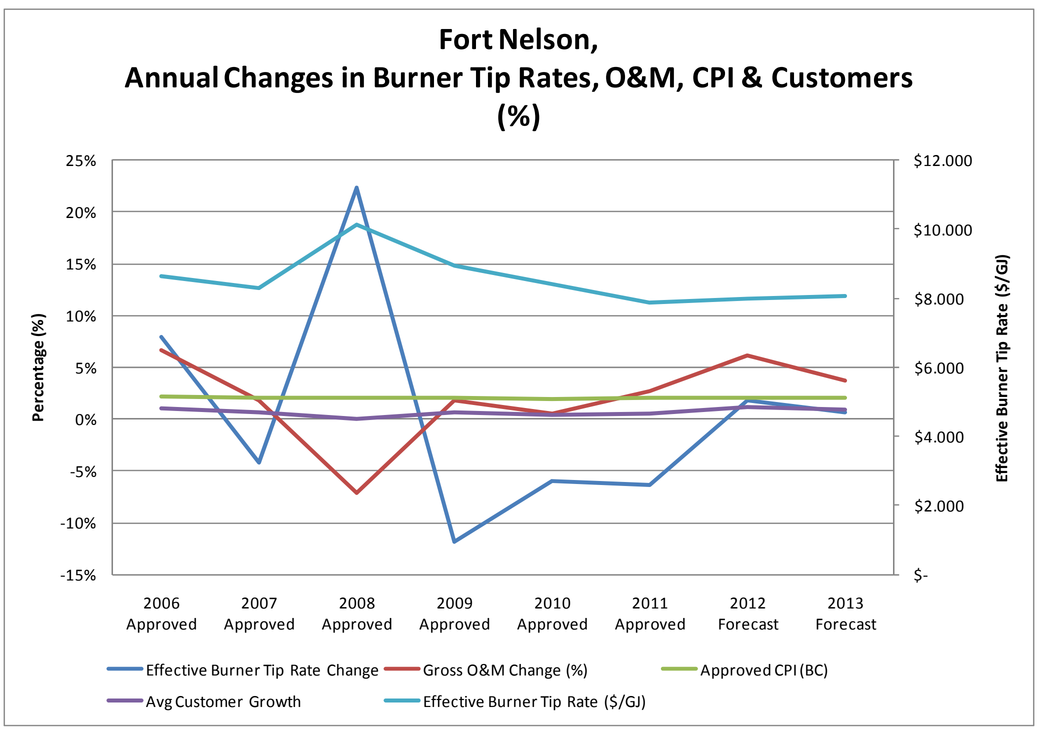
Mainland,
Annual Changes in Burner Tip Rates, O&M, CPI & Customers
(%)
Percentage (%)
Effective Burner Tip Rate ($/GJ)
15%
10%
5%
0%
-5%
-10%
-15%
-20%
$16.000
$14.000
$12.000
$10.000
$8.000
$6.000
$4.000
$2.000
$-
2006 Approved
2007 Approved
2008 Approved
2009 Approved
2010 Approved
2011 Approved
2012 Forecast
2013 Forecast
Effective Burner Tip Rate Change
Gross O&M Change (%)
Approved CPI (BC)
Avg Customer Growth
Effective Burner Tip Rate ($/GJ)



Vancouver Island,
Annual Changes in Burner Tip Rates, O&M, CPI & Customers
(%)
Percentage (%)
Effective Burner Tip Rate ($/GJ)
10%
8%
6%
4%
2%
0%
-2%
-4%
-6%
-8%
-10%
-12%
$16.600
$16.400
$16.200
$16.000
$15.800
$15.600
$15.400
$15.200
$15.000
$14.800
2006 Approved
2007 Approved
2008 Approved
2009 Approved
2010 Approved
2011 Approved
2012 Forecast
2013 Forecast
Effective Burner Tip Rate Change
Gross O&M Change (%)
Approved CPI (BC)
Avg Customer Growth
Effective Burner Tip Rate ($/GJ)



Whistler,
Annual Changes in Burner Tip Rates, O&M, CPI & Customers (%)
Percentage (%)
Effective Burner Tip Rate ($/GJ)
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
$30.000
$25.000
$20.000
$15.000
$10.000
$5.000
$-
2006 Approved
2007 Approved
2008 Approved
2009 Approved
2010 Approved
2011 Approved
2012 Forecast
2013 Forecast
Effective Burner Tip Rate Change
Gross O&M Change (%)
Approved CPI (BC)
Avg Customer Growth
Effective Burner Tip Rate ($/GJ)



Fort Nelson,
Annual Changes in Burner Tip Rates, O&M, CPI & Customers (%)
Percentage (%)
Effective Burner Tip Rate ($/GJ)
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
$12.000
$10.000
$8.000
$6.000
$4.000
$2.000
$-
2006 Approved
2007 Approved
2008 Approved
2009 Approved
2010 Approved
2011 Approved
2012 Forecast
2013 Forecast
Effective Burner Tip Rate Change
Gross O&M Change (%)
Approved CPI (BC)
Avg Customer Growth
Effective Burner Tip Rate ($/GJ)

136.0 Reference: Depreciation Study

Exhibit B-1, Application, Appendix E-1, p.II-33

Negative Salvage

The estimation of the net salvage percentages developed using the traditional approach, included the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period January 1, 2000 through December 31, 2009 were extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) was calculated for each historic year. Additionally, a net salvage amount was also calculated for each historic 3-year rolling band and the most recent 5-year rolling band.
3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year, in addition to 3-year rolling bands and the most recent 5-year rolling band.
4. The annual, the 3-year rolling average, and the most recent 5-year rolling average net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage was based purely upon statistical analysis.
5. Each account was then compared to the net salvage percentage currently approved and compared to peer natural gas transmission and distribution companies. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Gannett Fleming, a net salvage percentage was determined for each account.
6. The net salvage percentage was then used in the depreciation rate calculations in the technical update.

136.1 Please provide the detailed calculations and results for each asset class as performed by Gannett Fleming, in tabular format using at a minimum the data available for the last 10 years.

Response:

Gannett Fleming has included a description of all factors considered for each of the accounts where a net salvage recommendation is made at pages II-34 though II-47 of the Gannett Fleming report (Application (Exhibit B-1, Appendix E-1). Additionally the statistical analysis which includes all of the historic transactions reviewed in the consideration of the net salvage recommendations is provided in the Gannett Fleming report starting at Page V-2.

The table below is the source data used in the detailed analysis provided in the Gannett Fleming report starting at page V-2.

Asset Class	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Grand Total
44200							(1,959)	(17,458)	(6,000)		(25,417)
44300			-	(12,708)			(44,685)	(80,648)	(1,734)		(139,775)
44900		(30,000)		(96,616)		(214,983)	(111,600)	(196,414)	(1,297,755)	(82,431)	(2,029,799)
46200									(13,400)	(40,138)	(53,538)
46300		(26,672)		(75,177)	(86,997)		(50,237)	(40,820)		(4,405)	(284,308)
46400		(70)		-				(6,746)		(11,730)	(18,547)
46500	(719)	(1,219,906)	(657,746)	(1,850,075)	(682,967)	(749,466)	(576,912)	(124,402)	(67,495)	(703,198)	(6,632,888)
46600		(10,826)		(57,131)	-	(67,044)			(62,641)	-	(197,641)
46710		(251,311)	(178,402)	(309,532)	(1,928,908)	(139,586)	(206,490)	(275,309)	(26,600)	(231,628)	(3,547,768)
46800		(13,824)		(211,562)			(8,844)				(234,230)
47200	(13,168)	(104,190)	(40,060)	(78,668)	(953)	-	(50,994)	(54,534)	(80,293)	(35,094)	(457,955)
47300	(1,800,475)	(1,098,971)	(2,424,745)	(329,949)	(2,307,982)	(2,397,190)	(13,094,973)	(9,076,825)	(3,628,625)	(4,266,681)	(40,426,416)
47301			(50,047)	(13,262)	(24,860)	(88,506)	(69,978)	(63,250)	(73,430)	(52,540)	(435,873)
47400	(95,683)	(2,428,481)	(6,270,257)	(3,267,469)	(4,930,968)	(6,813,560)	(8,240,670)	(5,860,519)	(7,010,448)	(7,349,546)	(52,267,601)
47500	(4,430,340)	(485,250)	(998,123)	(88,626)	(408,796)	(810,205)	(2,667,611)	(2,127,563)	(2,405,264)	(3,348,332)	(17,770,109)
47501			(2,112)	(7,601)	(16,069)	(5,928)	(34,231)	(35,873)	(39,188)	(2,624)	(143,626)
47600	(7,475,766)	(91)									(7,475,857)
47730			(18,026)								(18,026)
47810	(679,275)	(2,117,588)	(3,437,049)	(2,018,918)	(2,729,515)	(4,879,690)	(3,821,305)	(3,118,099)	(4,782,171)	(4,143,930)	(31,727,540)
48400	(1,582,820)	(34,001)	(239,632)	(30,578)	(260,925)	(14,890)	(7,381)	(93,297)	(40,268)	(32,635)	(2,336,427)
48510	(13,523)		(6,318)				(34,952)	8,352			(46,441)
48520						(4,280)	(35,407)	(1)			(39,688)
Grand Total	**(16,091,770)**	**(7,821,182)**	**(14,322,519)**	**(8,447,870)**	**(13,378,939)**	**(16,185,329)**	**(29,058,229)**	**(21,163,406)**	**(19,535,313)**	**(20,304,913)**	**(166,309,470)**

To provide more clarity on the negative salvage rate determination process, the following provides more details on the process.

The process used by Gannett Fleming as described at page II-34 of the Gannett Fleming report is known as the "Traditional method" of net salvage analysis wherein the comparison of current day retirement costs applied to the originally installed cost of assets have been reviewed over a recent band of experience. This traditional method can be compared to inflation adjusted net estimation methods, such as the Constant Dollar Net Salvage ("CDNS") approach previously used in Alberta (by TransAlta Utilities Corporation) over the period of the early 1980's through 2002, or the method as described in the National Energy Board´s Decision RH-2-2008.

There are two components to the development of an appropriate future net salvage percentage for mass property accounts.

The first component is an estimate of the current net cost of removal of facilities. As the investment in most mass property accounts is normally comprised of a variety of asset sizes, attained ages, technologies, and in the circumstances of the FEU have included plant physically located throughout the Province with varying degrees of net cost of removal, it is difficult and not economically prudent to develop a detailed engineering estimate for the removal of all the plant that is currently in service such as is required by the NEB Decision RH-2-2008 for the federally regulated large diameter transmission pipelines. As such, the use of the historic ratio of net salvage costs to the original cost of plant retired is appropriate and used as one indicator of the current estimated cost of removal. The results of this study are presented starting at page V-2 of the Gannett Fleming report.

As the plant is removed a number of years following its installation, the cost of removal is usually greatly increased due to the impacts of inflation. In particular, the cost of removal is almost exclusively labour related. The inflationary pressures of the British Columbia labour market, due to numerous and unique labour fluctuations have a dramatic impact on the net cost of removal percentages. As such, a historic ratio of net salvage to original cost dollars retired has an inherent level of inflation built in.

The second component required in the future estimation of costs of removal, is to determine the cost required at the time of forecast retirement. Once the current estimate of the net costs of removal are established, the current estimate needs to be adjusted to recognize the impacts of inflation over the period from the current time, to the estimated remaining life of the account. In developing the inflation estimate to be applied to the current cost of removal estimate, inflation adjusted methods require the application of a forward looking estimate of the rate of inflation for labour costs connected with the retirement of facilities. In the circumstances of inflation adjusted methods, the current cost estimate has had all impacts of inflation removed. In comparison, when using the traditional method, because the current cost estimate is inclusive of historic rates of inflation, no further adjustment is made. Under the traditional method, a rate of inflation is used based on the historic rates of inflation that would have occurred between the points in time from the original installation of an asset and the time at which it was removed.

In the circumstances of this current study, in order to convert from the "traditional" method of estimating future net salvage proceeds to the use of inflation adjusted methods, the historic percentages (historic costs of removal, historic gross salvage proceeds, and original cost retirement dollars) would require re-basing to year 2009 dollars. The resultant net salvage ratio would then have all impacts of inflation removed, and would require the application of a specific forecast of the future rate of inflation applicable to utility labour, which will be applied over the composite remaining life of the asset group.

Please refer to the response to BCUC IR 1.136.4 for an account by account description of the specific factors considered in the development of the net salvage percentage recommendation.

136.2 Please confirm that all proceeds from the disposition of assets have been recorded in the asset account and have not been recorded as a gain or revenue in the last 10 years.

Response:

The plant accounting system of the FEU generate the entries for the gain and loss (remaining net book value net of salvage) on disposal of assets automatically. These entries are currently posted to the gain/loss deferral account. Prior to 2010, these entries were posted to the accumulated depreciation. In order for a gain or loss on disposal of an asset to be recorded in income, an entry would have to be processed to transfer the amount to income.

Through a review of annual financial statements and general ledger accounts for the last 10 years, the FEU are able to confirm that all proceeds from the disposition of assets have been recorded against accumulated depreciation and have not been recorded as a gain or revenue in the last 10 years, with the exception of the following items.

2001

Note 8 to the 2001 financial statements indicates that FEI received proceeds on sale of natural gas pipeline assets of $47.5 million. These proceeds were related to a LILO (lease in lease out) transaction which was deemed to not have occurred for regulatory purposes (the assets were not leased in and leased out for regulatory purposes but were instead treated as though the transaction did not occur). The financial statement note reads in part "Included in these amounts are payments for an operating lease for certain natural gas pipeline assets which were sold in October 2001. The pre-tax gain of $23.4 million on cash proceeds of $47.5 million has been deferred and is being amortized over the 17-year term of the lease." The decision and background on the LILO transactions is contained in Commission Order No. G-108-01.

2002

Note 11 to the 2002 financial statements indicates that FEI received proceeds on sale of natural gas distribution assets of $23.8 million and proceeds on sale of property, plant and equipment of $39.3 million. The $23.8 million was another LILO transaction as described above. The $39.3 million was a sale to the parent company, (then BC Gas Inc.), at net book value, related to the transfer of the customer care assets to CustomerWorks LP, which was approved by Commission Order No. G-29-02.

2004

Note 7 to the 2004 financial statements indicates that FEI received proceeds on sale of natural gas distribution assets of $64.6 million, and note 14(a) indicates that FEI received proceeds on sale of property, plant and equipment of $3.1 million. The $64.6 million was another LILO transaction as described above. The $3.1 million was a sale to the parent company at net book value, and came about due to creation of the corporate centre, as described and agreed to in Commission Order No.G-80-03. As part of this transaction, leasehold improvements, computer hardware and software, office furniture and equipment, and corporate aircraft with a net book value of $3.1 million was sold to Terasen Inc. at net book value.

2005

Note 7 to the 2005 financial statements indicates that FEI received proceeds on sale of natural gas distribution assets of $7.2 million. This is another LILO transaction as described above.

2007/2008

The 2007 and 2008 financial statements show a gain on sale of property, plant and equipment of $8.0 million and proceeds from sale of land of $14.1 million. This transaction was the Lochburn land sale, of which $2.5 million of the gain was shared with customers, as approved by Commission Order No. G-116-07.

Any income statement gains or losses recorded in the books of FEVI would have flowed through the RDDA in the past or the RSDA currently, although no evidence of material gains and losses was discovered for FEVI through the process undertaken to review the financial statements and general ledger records.

As evidenced above, any amounts recorded in the asset gain/loss income statement account are very rare, and any dispositions of property outside of the ordinary course of business require the approval of the Commission under Section 52 of the *Utilities Commission Act*.

As there are a number of questions in BCUC IR No. 1 related to the subject of Asset Accounting at the FEU, the following is background information regarding the FEU's asset accounting and depreciation processes to ensure the readers of the related information requests and the responses have the appropriate context.

The FEU believe their asset accounting system and processes are reasonable and sufficient to adequately account for the Companies' assets. The accounting followed is consistent with Generally Accepted Accounting Principles except where modified by direction from the Commission, either through specific orders or through the Uniform System of Accounts followed by natural gas utilities in British Columbia.

The FEU use a group system of accounting to account for the majority of its assets (i.e. meters and services). The group system, where assets are pooled together, is used 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 group. Accounting information captured in the fixed asset subledger is by asset class and year of installation and includes the historical costs incurred and the associated accumulated depreciation balance. Similarly, asset retirements and associated removal costs are tracked also by year and by asset class. In addition, where applicable, statistical metrics are kept including the length and size of distribution mains and services by year. This information is used to maintain the asset records and support the retirement of assets.

Assets are depreciated using estimated depreciation rates following a straight line basis where an equal amount of the costs are distributed to each year of the assets' lives. Gains and losses recorded resulting from the retirement or abandonment of assets are recorded in accordance with Commission direction – prior to 2010 the gains and losses were transferred to the accumulated depreciation account and for 2010 and 2011 the gains and losses were recorded in a deferral account. In the case of the FEU's assets, a "loss" is defined as the difference between the remaining net book value of an asset and any salvage proceeds. As depreciation expense is recorded based on an estimated depreciation rate, a "loss" results primarily from the difference between the actual life of an asset and the estimated life on which the depreciation rate is based. Over the life of an asset, factors beyond the FEU's control can influence an asset's estimated life including changes in technology and operating requirements. As such, recording a "loss" when retiring an asset earlier than expected is not due to lack of prudence by the FEU management and instead is reflective of changes in the environment in which the FEU operate that has influence over an asset's actual life. In addition, for the FEU, a "loss" is not due to acquiring and selling assets for the purpose of profiting but instead due to changes in the estimated period (i.e. service life) over which the cost of the assets are recovered from customers. The FEU acquire and use their assets for the primary purpose of providing safe and reliable natural gas delivery service. The FEU do not retire assets just for the purpose of selling the assets.

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.

Over the years, the FEU have consistently followed the practice of engaging an external depreciation specialist in updating its depreciation rates, with the current depreciation rates in place those that were approved by the Commission as part of the FEU's most recent Revenue Requirements applications.

136.3 Please confirm that FEU has outsourced the management function of determining both the i) depreciation rates and ii) negative salvage rates to Gannett Fleming.

Response:

Management of the FEU have appropriately managed and overseen the determination of depreciation and negative salvage rates. As indicated in the response to BCUC IR 1.136.2 above, over the past years, the FEU have consistently followed the practice of engaging an external depreciation specialist to update its depreciation rates, with the current depreciation rates in place those that were approved by the Commission as part of FEU's most recent

Revenue Requirements applications. The same approach was followed in the determination of the proposed negative salvage rates.

136.4 For each asset account class, please provide a table listing the following considerations for each negative salvage rate:

Factors considered : **(such as)**	**Weighting placed on this factor (as a % of 100%)**	**Notes (if applicable)**
Industry experience		
Historical experience of Utility		
Expected innovations in technology		
Expected scenarios discussed with Utility Staff		
Other		

Response:

Please refer to the following table.

FORTISBC ENERGY INC.

ESTIMATION OF APPROXIMATE WEIGHTING APPLIED TO EACH NET SALVAGE FACTOR

Factors considered :	Historical experience of Utility	Peer Industry experience	Gannett Fleming Professional Judgement	Expected innovations in technology	Discussions with FortisBCStaff
Account:					
442 - LNG Gas- Structures	25	25	50		
443.-LNG Gas - Equipment		25	75		
449- LNG Gas - Other Equipment	25	25	50		
462- Transmission Plant - Compressor Structures	25	35			40
463- Transmission Plant - Meas. And Reg. Structures	25	35			40
464- Transmission Plant - Other Structures	25	35			40
465- Transmission Plant - Transmission Pipeline	60	20			20
466- Transmission Plant - Compressor Equipment	25	25	25		25
467.10- Transmission Plant - Meas. And Reg. Equipment	50	25			25
468- Transmission Plant - Communications Equipment	0	50			50
472- Distribution Plant - Structures	25	35			40
473- Distribution Plant - Services	80	10			10
474- Distribution Plant - Meters/Reg Installations	80	10			10
475- Distribution Plant - Mains	30	40			30
476- Distribution Plant - NGV Fuel Equipment					100
477.3- Distribution Plant - Meas. And Reg. Equipment					100
478.1- Distribution Plant - Meters	25	25			50
484 - General Plant - Vehicles		50			50
485.1 - General Plant - Heavy Work Equipment		50			50
485.2 - General Plant - Heavy Mobile Equipment		50			50

136.5 How many years have FEU engaged of Gannett Fleming?

Response:

The FEU have engaged Gannett Fleming for more than a decade with a depreciation study completed for FEI, formerly BC Gas Utility, dated December 31, 1998.

136.6 How many other Fortis related utilities does Gannett Fleming perform services for in Canada?

Response:

Gannett Fleming provides services to the following Fortis related utilities in Canada including:

- FortisBC Inc.
- FortisBC Energy Utilities
- FortisAlberta
- Maritime Electric
- Newfoundland Power

In addition, Gannett Fleming has conducted depreciation studies in recent years for the following Canadian Natural Gas Utilities (other than the FEU):

- AltaGas Utilities, Inc.
- Enbridge Consumers Gas
- Centra Gas Manitoba
- Enbridge Pipelines, Inc.
- Heritage Gas Limited
- NOVA Gas Transmission Ltd.
- TransCanada Pipe Lines Limited

136.7 Please confirm that the annual retirement, gross salvage and cost of removal transactions for the period from 2000 to 2009 extracted from the system for Gannett Fleming constituted all asset retirements for the period of time. If some asset retirements were not included in this extraction, please explain why these amounts were excluded. Discuss how the request for the new Gas Assets records project discussed in part 6.3.5.11 ties into the ability to extract data.

Response:

Gannett Fleming was provided with all annual retirement, gross salvage and cost of removal transactions for the period from 2000-2009 in support of the depreciation study on our regulated assets.

The new Gas Assets records project's primary purpose is to focus on capturing critical gas system asset compliance records into a formal and rigorous management system. The Gas Asset records capture primarily physical and technical information regarding gas assets rather than financial information for Asset Accounting.

136.8 Are there any annual retirement, gross salvage and cost of removal transactions that would have occurred during 2000-2009 that were not recorded in the system?

Response:

No, all annual retirement, gross salvage and cost of removal transactions occurring during 2000-2009 were recorded in the asset accounting system.

136.9 Were any of this annual retirement, gross salvage and cost of removal transactions included in the system on a combined or group basis (i.e. any transactions that were not reported on a single asset retirement basis)?

Response:

In accordance with mass asset accounting, the majority of retirement transactions are accounted for on a group basis. For example, for distribution mains and services, retirement transactions are grouped by year (i.e. year of installation), the size of the pipe (mm/inch) with the length (metres) of pipe retired noted.

The FEU do track retirement of assets on a "single asset" basis for specific asset categories including measurement and regulating stations and telemetry, buildings, owned vehicles and heavy work and mobile equipment.

136.10 Can Gannett Fleming provide a comment as to their assessment of the quality, accuracy and completeness of the data contained within and extracted from the system as described above?

Response:

This response has been provided by Gannett Fleming.

Gannett Fleming has prepared a number of depreciation studies for the FEU (and formerly Terasen Gas Inc. and BC Gas Utility Inc.). In all studies, Gannett Fleming has found the data provided to Gannett Fleming to be of good quality and of a sufficient level of detail and quality to complete the depreciation analysis. Gannett Fleming has not had any issue in reconciling the source depreciation data to the financial ledgers of the Companies and has made only a limited amount of adjustments to the data in order to complete our detailed analysis. The minor adjustments were of a type that would normally be made in the conduct of depreciation studies and would include adjustments to align offsetting entries made in concurrent years (for accrued addition and retirement transactions).

136.11 Did Gannett Fleming make any recommendations to improve the quality of the asset management or accounting systems? If so, please provide these comments.

Response:

No, Gannett Fleming did not make any recommendations to improve the systems.

136.12 Did Gannet Fleming provide any additional reports to management during or at the conclusion of its report, including informal communications such as emails or phone discussions that summarize his opinions, findings or suggestions resulting from the completion of the work performed? If so, please provide such documents or a summary of such oral presentation.

Response:

No such additional reports were provided.

136.13 Were any items resulting from the deprecation study reported to the Board of Directors, Board Committees, or senior management? If so, what were they?

Response:

The high-level results of the recently completed depreciation study including the significant drivers of depreciation rate changes (i.e. meters) were shared with senior management. Additionally, senior management reviewed the revenue requirement application including the depreciation study.

136.14 Do the Companies conduct their own depreciation study/analysis which is reviewed during Gannett Fleming's engagement? If not, does anyone independent of Gannett Fleming review their work?

Response:

No, the FEU have not conducted their own depreciation study/analysis and have not hired anyone independent of Gannett Fleming to review their work. However, as in the past, the FEU have worked actively with Gannett Fleming in completing the depreciation study. In addition to providing the financial data requested by Gannett Fleming, the FEU review the recommended depreciation rates for accuracy, reasonableness and applicability to its assets.

As indicated in the response to BCUC IR 1.136.2, the FEU follow a common industry practice for utilities where utility staff work with an external depreciation specialist to determine its 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.

As indicated earlier, over the years, the FEU have consistently followed the practice of engaging an external depreciation specialist to update its depreciation rates, with the current depreciation rates in place those that were approved by the Commission as part of the FEU's most recent Revenue Requirements applications.

136.15 Please complete the following tables for each Utility:

Asset Account	**Forecast Negative salvage estimated amount 2011**	**Forecast Negative salvage estimated amount 2012**	**Actual Salvage costs incurred in 2011 (projection)**	**Average remaining salvage life of asset class, end of year**	**Actual Salvage costs incurred in 2010 (projection)**	**Average remaining salvage life of asset class, end of year**
Acct XX.XX Acct description						
Total						

Asset Account	**Forecast asset account balance, mid-year**	**Forecast annual Depreciation expense 2011**	**Forecast Negative Salvage expense 2011**	**Forecast Actual Salvage Costs 2011**	**Forecast Annual Depreciation expense 2012**	**Forecast Negative Salvage expense 2012**	**Forecast Actual Salvage Costs 2012**
Acct XX.XX Acct description							
Total							

Response:

Provided below are the tables for each utility. Fort Nelson has been excluded since there were no negative salvage provisions for that utility. In addition, the two tables have been combined into one table for each utility to simplify the information and eliminate duplicate columns.

FEI (Mainland)

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
117-00 Utility Plant Acquisition Adjustment						-	-	-	-
175-00 Unamortized Conversion Expense						109	(1)	109	(1)
175-00 Unamortized Conversion Expense - Squamish						777	(78)	777	(78)
178-00 Organization Expense						728	(7)	728	(7)
179-01 Other Deferred Charges						-	-	-	-
401-00 Franchise and Consents				1.0		99	(20)	99	(49)
402-00 Utility Plant Acquisition Adjustment						62	(15)	62	(36)
402-00 Other Intangible Plant				32.0		688	(15)	688	(16)
431-00 Mfg'd Gas Land Rights							-		-
461-00 Transmission Land Rights						44,105	-	44,330	-
461-10 Transmission Land Rights - Byron Creek						15	-	15	-
471-00 Distribution Land Rights						1,211	-	1,211	-
471-10 Distribution Land Rights - Byron Creek						(0)	-	(0)	-
402-01 Application Software - 12.5%				4.4		42,669	(5,334)	120,117	(11,507)
402-02 Application Software - 20%				3.4		13,838	(2,768)	18,644	(3,729)
TOTAL INTANGIBLE PLANT	0	0	0		0	104,301	(8,238)	186,779	(15,423)
430-00 Manufact'd Gas - Land						31		31	
431-00 Manufact'd Gas - Land Rights								-	
432-00 Manufact'd Gas - Struct. & Improvements				23.2		464	(15)	464	(16)
433-00 Manufact'd Gas - Equipment				9.8		146	(9)	180	(12)
434-00 Manufact'd Gas - Gas Holders				22.0		358	(14)	358	(8)
436-00 Manufact'd Gas - Compressor Equipment				10.9		53	(3)	53	(3)
437-00 Manufact'd Gas - Measuring & Regulating Equipment				3.2		309	(60)	309	(49)
443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)								-	
440/441-00 Land in Fee Simple and Land Rights (Tilbury)						928		7,984	
442-00 Structures & Improvements (Tilbury)				16.3		4,959	(181)	5,253	(188)
443-00 Gas Holders - Storage				26.2		16,494	(360)	16,494	(318)
446-00 Compressor Equipment (Tilbury)								-	
447-00 Measuring & Regulating Equipment (Tilbury)								-	
448-00 Purification Equipment (Tilbury)								-	
449-00 Local Storage Equipment (Tilbury)				16.0	(1)	25,407	(854)	27,731	(1,176)
440/441-00 Land in Fee Simple and Land Rights (Mount Hay e									
TOTAL MANUFACTURED GAS / LOCAL STORAGE	0	0	0		(1)	49,149	(1,496)	58,857	(1,770)

FEI (Mainland)

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
460-00 Land in Fee Simple						7,402	-	7,402	
461-00 Transmission Land Rights						106	-	212	
461-10 Land Rights - Byron Creek							-		
462-00 Compressor Structures				17.8		14,729	(566)	14,729	(551)
463-00 Measuring Structures				20.0		5,380	(230)	5,380	(204)
464-00 Other Structures & Improvements				27.6		6,014	(173)	6,014	(170)
465-00 Mains				53.6	(177)	764,501	(12,110)	800,493	(11,520)
465-00 Mains - INSPECTION						3,625	(539)	5,118	(761)
465-11 IP Transmission Pipeline - Whistler							-		-
465-30 Mt Hayes - Mains							-		-
465-10 Mains - Byron Creek						971	(49)	971	(49)
466-00 Compressor Equipment				24.4	(2)	109,569	(3,484)	113,090	(3,246)
466-00 Compressor Equipment - OVERHAUL						2,285	(102)	2,285	(102)
467-00 Mt. Hayes - Measuring and Regulating Equipme n							-		
467-00 Measuring & Regulating Equipment				19.3		28,208	(2,028)	28,208	(1,204)
467-10 Telemetering				14.0		6,536	(87)	6,846	(21)
467-31 IP Intermediate Pressure Whistler							-		-
467-20 Measuring & Regulating Equipment - Byron Creek						39	(2)	39	-
468-00 Communication Structures & Equipment				5.2		346	(18)	346	(15)
469-00 Other Transmission Equipment							-		-
TOTAL TRANSMISSION PLANT	0	0	0		(180)	949,711	(19,388)	991,133	(17,843)
470-00 Land in Fee Simple						3,414	-	3,414	
471-00 Distribution Land Rights							-	25	
471-10 Land Rights - Byron Creek							-		
472-00 Structures & Improvements				24.0	(0)	15,643	(563)	15,643	(521)
472-10 Structures & Improvements - Byron Creek						107	(5)	107	(5)
473-00 Services	(9,685)	(9,209)	(11,481)	40.9	(7112)	674,038	(15,166)	693,519	(15,882)
473-00 Services - LILO				12.9		43,063	(947)	43,024	(2,543)
474-00 House Regulators & Meter Installations	(500)	(2,700)	(593)	13.3	(2221)	142,555	(7,427)	149,667	(11,135)
474-00 House Regulators & Meter Installations - LILO				13.1		16,070	(352)	16,070	(598)
477-00 Meters/Regulators Installations						-	-	7,466	(340)
475-00 Mains	(500)	(700)	(593)	52.0	(438)	881,380	(16,658)	907,494	(13,431)
475-00 Mains - LILO				13.4		39,741	(795)	39,717	(1,803)

FEI (Mainland)

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
476-00 Compressor Equipment				1.7		1,026	(257)	1,026	(272)
477-00 Measuring & Regulating Equipment	(105)		(124)	17.4		84,123	(4,812)	88,708	(4,214)
477-00 Telemetering						6,344	(16)	6,858	(17)
477-10 Measuring & Regulating Equipment - Byron Creek					(17)	163	-	163	-
478-10 Meters	(500)		(593)	9.9	4	196,387	(10,428)	203,498	(16,056)
478-11 Meters - LILO				11.4		10,027	(330)	10,027	(524)
478-20 Instruments				23.8		11,501	(463)	11,501	(362)
479-00 Other Distribution Equipment						-	-	-	-
TOTAL DISTRIBUTION PLANT	(11,290)	(12,609)	(13,384)		(9,783)	2,125,580	(58,219)	2,197,924	(67,703)
472-00 Bio Gas Struct. & Improvements						-	-	-	
475-10 Bio Gas Mains – Municipal Land						-	-	-	
475-20 Bio Gas Mains – Private Land						94	(2)	324	(5)
418-10 Bio Gas Purification Overhaul						201	-	609	(81)
418-20 Bio Gas Purification Upgrader						804	-	2,432	(162)
474-10 Bio Gas Reg & Meter Installations						841	(44)	1,955	(145)
478-30 Bio Gas Meters						20	(1)	243	(19)
TOTAL BIO GAS	0	0	0		0	1,959	(47)	5,562	(412)
476-10 NG Transportation CNG Dispensing Equipment						1,020	(51)	3,078	(154)
476-20 NG Transportation LNG Dispensing Equipment						869	(43)	2,533	(127)
476-30 NG Transportation CNG Foundations						225	(11)	679	(34)
476-40 NG Transportation LNG Foundations						191	(10)	559	(28)
476-50 NG Transportation LNG Pumps (Pumps only apply to LNG)						412	(41)	1,202	(120)
476-60 NG Transportation CNG Dehydrator						80	(4)	240	(12)
476-70 NG Transportation LNG Dehydrator						-	-	-	-
TOTAL NG FOR TRANSPORTATION	0	0	0		0	2,797	(160)	8,290	(475)
480-00 Land in Fee Simple						20,207	-	21,271	
481-00 Land Rights						-	-	-	
482-00 Structures & Improvements						-	-	-	
- Frame Buildings				14.6		7,895	(290)	7,892	(380)
- Masonry Buildings				39.6		84,806	(2,120)	91,594	(2,043)
- Leasehold Improvement						211	(37)	4,888	(338)

FEI (Mainland)

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Office Equipment & Furniture						-	-	-	-
483-30 GP Office Equipment				7.1		3,512	(234)	4,344	(277)
483-40 GP Furniture				8.4		20,039	(1,002)	23,711	(1,117)
483-10 GP Computer Hardware				2.8		17,590	(3,518)	28,724	(5,393)
483-20 GP Computer Software				6.1		1,662	(208)	1,583	(198)
483-21 GP Computer Software				4.9		0	(0)		(0)
483-22 GP Computer Software						-	-		
484-00 Vehicles				4.7		1,378	(106)	1,508	(78)
484-00 Vehicles - Leased						27,739	(2,911)	29,117	(3,086)
485-10 Heavy Work Equipment				6.3		270	(18)	270	(24)
485-20 Heavy Mobile Equipment				4.0		943	(80)	1,123	(203)
486-00 Small Tools & Equipment				12.2		39,973	(1,999)	41,765	(2,088)
487-00 Equipment on Customer's Premises				12.2		24	(2)	24	(2)
- VRA Compressor Installation Costs						-	-	-	-
488-00 Communications Equipment						-	-	-	-
- Telephone				7.1		7,771	(518)	7,841	(523)
- Radio				10.1		4,998	(333)	4,563	(304)
489-00 Other General Equipment						-	-	-	-
TOTAL GENERAL PLANT & EQUIPMENT	0	0	0		0	239,015	(13,376)	270,216	(16,054)
499 Plant Suspense									
497 Allowance for Funds Used During Construction									
TOTAL UNCLASSIFIED PLANT	0	0	0		0	-	-	-	-
Total	(11,290)	(12,609)	(13,384)		(9,963)	3,472,509	(100,924)	3,718,759	(119,680)

Vancouver Island

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
117-00 Utility Plant Acquisition Adjustment							-	-	-
175-00 Unamortized Conversion Expense							-	-	-
175-00 Unamortized Conversion Expense - Squamish							-	-	-
178-00 Organization Expense							-	-	-
179-01 Other Deferred Charges							-	-	-
401-00 Franchise and Consents				22		190	(6)	190	(6)
402-00 Utility Plant Acquisition Adjustment							-	-	-
402-00 Other Intangible Plant				28.5		1,219	(28)	1,219	(23)
431-00 Mfg'd Gas Land Rights							-	-	-
461-00 Transmission Land Rights						6,847	-	6,847	-
461-13 IP Land Rights Whistler						24	-	24	-
471-00 Distribution Land Rights						1,866	-	1,866	-
471-10 Distribution Land Rights - Byron Creek						-	-	-	-
402-01 Application Software - 12.5%				4.4		16,044	(2,005)	25,009	(2,755)
402-02 Application Software - 20%				4.9		2,834	(567)	3,323	(664)
TOTAL INTANGIBLE PLANT	0	0	0		0	29,023	(2,606)	38,478	(3,448)
430-00 Manufact'd Gas - Land							-	-	-
431-00 Manufact'd Gas - Land Rights							-	-	-
432-00 Manufact'd Gas - Struct. & Improvements							-	-	-
433-00 Manufact'd Gas - Equipment							-	-	-
434-00 Manufact'd Gas - Gas Holders							-	-	-
436-00 Manufact'd Gas - Compressor Equipment							-	-	-
437-00 Manufact'd Gas - Measuring & Regulating Equipment							-	-	-
440/441 Land in Fee Simple and Land Rights (Mount Hayes)							-	-	-
442 Structures & Improvements (Mount Hayes)							(407)	-	(698)
443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)							-	-	-
440/441-00 Land in Fee Simple and Land Rights (Tilbury)						506	-	1,012	-
442-00 Structures & Improvements (Tilbury)						18,825	-	17,442	-
443-00 Gas Holders - Storage							-	-	-
443 Gas Holders - Storage (Mount Hayes)						65,577	(592)	61,132	(1,021)
446 Compressor Equipment (Mount Hayes)							-	-	-
Piping (Mount Hayes)						12,525	(169)	11,605	(290)
Pre-treatment (Mount Hayes)						31,313	(677)	29,012	(1,160)
Liquefaction Equipment (Mount Hayes)						31,313	(423)	29,012	(725)
Send Out Equipment (Mount Hayes)						11,619	(290)	23,237	(581)
Sub-station and Electric (Mount Hayes)						11,233	(281)	22,466	(562)
Control Room (Mount Hayes)						2,962	(198)	5,923	(395)

Vancouver Island

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
449 Local Storage Equipment (Mount Hayes)						187	(3)	173	(5)
446-00 Compressor Equipment (Tilbury)							-	-	-
447-00 Measuring & Regulating Equipment (Tilbury)							-	-	-
448-00 Purification Equipment (Tilbury)							-	-	-
449-00 Local Storage Equipment (Tilbury)							-	-	-
440/441-00 Land in Fee Simple and Land Rights (Mount Hay e							-	-	-
TOTAL MANUFACTURED GAS / LOCAL STORAGE	0	0	0		0	186,060	(3,040)	201,014	(5,437)
460-00 Land in Fee Simple						2,842	-	2,842	-
461-00 Transmission Land Rights						39	-	118	-
461-10 Land Rights - Byron Creek						401	-	801	-
462-00 Compressor Structures				20.1		11,705	(435)	11,705	(417)
463-00 Measuring Structures				22	(181)	7,517	(216)	7,517	(227)
464-00 Other Structures & Improvements				30.9		130	(4)	130	(4)
465-00 Mains				48.4		324,971	(5,622)	329,921	(5,114)
465-00 Mains - INSPECTION						3,098	(443)	3,607	(515)
465-11 IP Transmission Pipeline - Whistler				70		41,927	(725)	41,927	(600)
465-30 Mt Hayes - Mains						6,492	(54)	6,015	(93)
465-10 Mains - Byron Creek						-	-	-	-
466-00 Compressor Equipment				26.5		59,400	(1,895)	61,411	(1,781)
466-00 Compressor Equipment - OVERHAUL						4,871	(1,303)	6,748	(1,806)
467-00 Mt. Hayes - Measuring and Regulating Equipme n						5,946	(119)	5,509	(204)
467-00 Measuring & Regulating Equipment					(5)	14,030	(784)	14,064	(605)
467-10 Telemetering				18		41	(2)	41	(2)
467-31 IP Intermediate Pressure Whistler				25		313	(18)	313	(13)
467-20 Measuring & Regulating Equipment - Byron Creek						-	-	-	-
468-00 Communication Structures & Equipment				4.4		3,780	(381)	3,780	(452)
469-00 Other Transmission Equipment							-	-	-
TOTAL TRANSMISSION PLANT	0	0	0		(186)	487,502	(12,001)	496,449	(11,833)
470-00 Land in Fee Simple						799	-	799	-
471-00 Distribution Land Rights						-	-	-	-
471-10 Land Rights - Byron Creek							-	-	-
472-00 Structures & Improvements				20.1		2,302	(74)	2,302	(71)
472-10 Structures & Improvements - Byron Creek						-	-	-	-
473-00 Services	(119)	(250)	(177)	42.8	(291)	176,739	(3,376)	183,176	(3,664)

Vancouver Island

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
473-00 Services - LILO						-	-	-	-
474-00 House Regulators & Meter Installations	(175)		(260)	13	(263)	23,293	(804)	23,796	(1,371)
474-00 House Regulators & Meter Installations - LILO						-	-	-	-
477-00 Meters/Regulators Installations						-	-	424	(19)
475-00 Mains	(50)	(207)	(74)	53	(64)	282,817	(4,582)	291,201	(4,339)
475-00 Mains - LILO						-	-	-	-
476-00 Compressor Equipment						-	-	-	-
477-00 Measuring & Regulating Equipment		(175)			(6)	8,474	(390)	8,828	(384)
477-00 Telemetering						62	-	186	-
477-10 Measuring & Regulating Equipment - Byron Creek				14.5		-	-	-	-
478-10 Meters				11.2	(14)	13,795	(603)	14,248	(905)
478-11 Meters - LILO							-	-	-
478-20 Instruments							-	-	-
479-00 Other Distribution Equipment							-	-	-
TOTAL DISTRIBUTION PLANT	(344)	(632)	(511)		(638)	508,281	(9,829)	524,958	(10,753)
480-00 Land in Fee Simple						1,268	-	4,446	-
481-00 Land Rights						-	-	-	-
482-00 Structures & Improvements						-	-	-	-
- Frame Buildings				13		3,959	(173)	3,959	(255)
- Masonry Buildings				44.4		1,089	(47)	5,596	(124)
- Leasehold Improvement				15.7		487	(97)	914	(30)
Office Equipment & Furniture						-	-	-	-
483-30 GP Office Equipment				4.3		653	(44)	711	(47)
483-40 GP Furniture				18		379	(19)	981	(40)
483-10 GP Computer Hardware				3.3		2,315	(463)	3,585	(680)
483-20 GP Computer Software				6.6		261	(52)	261	(33)
483-21 GP Computer Software				4.8		-	-	-	-
483-22 GP Computer Software				1		51	(10)	51	(10)
484-00 Vehicles				3.1	27	5,513	(986)	7,302	(1,294)
484-00 Vehicles - Leased						-	-	-	-
485-10 Heavy Work Equipment				6		325	(21)	318	(19)
485-20 Heavy Mobile Equipment				5.5		1,190	(87)	1,347	(199)
486-00 Small Tools & Equipment				10.4		6,670	(333)	6,424	(321)

Vancouver Island

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
487-00 Equipment on Customer's Premises						-	-	-	-
- VRA Compressor Installation Costs						-	-	-	-
488-00 Communications Equipment						-	-	-	-
- Telephone				7.1		659	(44)	576	(38)
- Radio							-	-	-
489-00 Other General Equipment							-	-	-
TOTAL GENERAL PLANT & EQUIPMENT	0	0	0		27	24,817	(2,376)	36,467	(3,090)
499 Plant Suspense								-	-
497 Allowance for Funds Used During Construction								-	-
TOTAL UNCLASSIFIED PLANT	0	0	0		0	-	-		-
Total	(344)	(632)	(511)		(797)	1,235,683	(29,852)	1,297,366	(34,561)

Whistler

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
117-00 Utility Plant Acquisition Adjustment						-	-	-	-
175-00 Unamortized Conversion Expense						-	-	-	-
175-00 Unamortized Conversion Expense - Squamish						-	-	-	-
178-00 Organization Expense						-	-	-	-
179-01 Other Deferred Charges						-	-	-	-
401-00 Franchise and Consents				18		8	-	8	-
402-00 Utility Plant Acquisition Adjustment						-	-	-	-
402-00 Other Intangible Plant						-	-	-	-
431-00 Mfg'd Gas Land Rights						-	-	-	-
461-00 Transmission Land Rights						-	-	-	-
461-10 Transmission Land Rights - Byron Creek						-	-	-	-
471-00 Distribution Land Rights						87	(1)	87	-
471-10 Distribution Land Rights - Byron Creek						-	-	-	-
402-01 Application Software - 12.5%						-	-	251	(21)
402-02 Application Software - 20%						-	-	-	-
TOTAL INTANGIBLE PLANT	0	0	0		0	95	(1)	346	(21)
430-00 Manufact'd Gas - Land						450	-	-	-
431-00 Manufact'd Gas - Land Rights						-	-	-	-
432-00 Manufact'd Gas - Struct. & Improvements						-	-	-	-
433-00 Manufact'd Gas - Equipment						-	-	-	-
434-00 Manufact'd Gas - Gas Holders						-	-	-	-
436-00 Manufact'd Gas - Compressor Equipment						-	-	-	-
437-00 Manufact'd Gas - Measuring & Regulating Equipment						-	-	-	-
443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)						-	-	-	-
440/441-00 Land in Fee Simple and Land Rights (Tilbury)						-	-	-	-
442-00 Structures & Improvements (Tilbury)						-	-	-	-
443-00 Gas Holders - Storage						-	-	-	-
446-00 Compressor Equipment (Tilbury)						-	-	-	-
447-00 Measuring & Regulating Equipment (Tilbury)						-	-	-	-
448-00 Purification Equipment (Tilbury)						-	-	-	-
449-00 Local Storage Equipment (Tilbury)						-	-	-	-
440/441-00 Land in Fee Simple and Land Rights (Mount Hay e						-	-	-	-
TOTAL MANUFACTURED GAS / LOCAL STORAGE	0	0	0		0	450	-	-	-

Whistler

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
460-00 Land in Fee Simple						-	-	-	-
461-00 Transmission Land Rights						-	-	-	-
461-10 Land Rights - Byron Creek						-	-	-	-
462-00 Compressor Structures						-	-	-	-
463-00 Measuring Structures						-	-	-	-
464-00 Other Structures & Improvements						-	-	-	-
465-00 Mains						-	-	-	-
465-00 Mains - INSPECTION						-	-	-	-
465-11 IP Transmission Pipeline - Whistler						-	-	-	-
465-30 Mt Hayes - Mains						-	-	-	-
465-10 Mains - Byron Creek						-	-	-	-
466-00 Compressor Equipment						-	-	-	-
466-00 Compressor Equipment - OVERHAUL						-	-	-	-
467-00 Mt. Hayes - Measuring and Regulating Equipme n						-	-	-	-
467-00 Measuring & Regulating Equipment						-	-	-	-
467-10 Telemetering						-	-	-	-
467-31 IP Intermediate Pressure Whistler						-	-	-	-
467-20 Measuring & Regulating Equipment - Byron Creek						-	-	-	-
468-00 Communication Structures & Equipment						-	-	-	-
469-00 Other Transmission Equipment						-	-	-	-
TOTAL TRANSMISSION PLANT	0	0	0		0	-	-	-	-
470-00 Land in Fee Simple						-	-	-	-
471-00 Distribution Land Rights						-	-	-	-
471-10 Land Rights - Byron Creek						-	-	-	-
472-00 Structures & Improvements				27.5		2	-	2	-
472-10 Structures & Improvements - Byron Creek						-	-	-	-
473-00 Services	(5)	(5)	(5)	43.7	(3)	3,961	(77)	4,106	(85)
473-00 Services - LILO						-	-	-	-
474-00 House Regulators & Meter Installations				15.3	(4)	1,417	(47)	1,432	(73)
474-00 House Regulators & Meter Installations - LILO						-	-	-	-
477-00 Meters/Regulators Installations				25.4		-	-	11	(1)
475-00 Mains		(1)		55.9	(0)	8,878	(147)	9,194	(139)
475-00 Mains - LILO						-	-	-	-
476-00 Compressor Equipment						0	-	0	-
477-00 Measuring & Regulating Equipment						640	(29)	640	(25)
477-00 Telemetering				26.9		2	-	2	-
477-10 Measuring & Regulating Equipment - Byron Creek						-	-	-	-

Whistler

Asset Account	Estimated removal costs 2011	Estimated removal costs 2012	Actual removal costs 2011 (projection)	Average remaining service life of asset class, end of year 2011	Actual removal costs 2010	Projected asset account balance, mid-year 2011	Projected annual Depreciation expense 2011	Forecast asset account balance, mid-year 2012	Forecast annual Depreciation expense 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
478-10 Meters				12.2	(1)	468	(22)	479	(31)
478-11 Meters - LILO						-	-	-	-
478-20 Instruments						-	-	-	-
479-00 Other Distribution Equipment						-	-	-	-
TOTAL DISTRIBUTION PLANT	(5)	(6)	(5)		(9)	15,367	(322)	15,866	(354)
480-00 Land in Fee Simple						-	-	-	-
481-00 Land Rights						-	-	-	-
482-00 Structures & Improvements						-	-	-	-
- Frame Buildings				12.2		17	(1)	17	(1)
- Masonry Buildings						13	(1)	137	(6)
- Leasehold Improvement						-	-	53	(5)
Office Equipment & Furniture						-	-	-	-
483-30 GP Office Equipment				3		9	(1)	11	(1)
483-40 GP Furniture						-	-	20	(1)
483-10 GP Computer Hardware						-	-	16	(2)
483-20 GP Computer Software						-	-	-	-
483-21 GP Computer Software						-	-	-	-
483-22 GP Computer Software						-	-	-	-
484-00 Vehicles				4.3		163	(26)	158	(21)
484-00 Vehicles - Leased						-	-	-	-
485-10 Heavy Work Equipment				5.8		94	(4)	92	(3)
485-20 Heavy Mobile Equipment						-	-	-	-
486-00 Small Tools & Equipment				8.6		183	(9)	177	(9)
487-00 Equipment on Customer's Premises						-	-	-	-
- VRA Compressor Installation Costs						-	-	-	-
488-00 Communications Equipment						-	-	-	-
- Telephone				3		16	(1)	16	(1)
- Radio						-	-	-	-
489-00 Other General Equipment						-	-	-	-
TOTAL GENERAL PLANT & EQUIPMENT	0	0	0		0	493	(43)	696	(50)
499 Plant Suspense						-	-	-	-
497 Allowance for Funds Used During Construction						-	-	-	-
TOTAL UNCLASSIFIED PLANT	0	0	0		0	-	-	-	-
Total	(5)	(6)	(5)		(9)	16,405	(366)	16,907	(425)

Note: The average remaining service life of asset class (column 4 of schedule) was obtained from the latest depreciation study.

137.0 Reference: Depreciation Study

Exhibit B-1, Application, Appendix E-1, p.II-33

Negative Salvage

In National Energy Board (NEB) Reasons for Decision RH 2-2008 (Attachment 3), the NEB considered various factors to assess the application of negative salvage to pipeline abandonment in Canada. The asset life of pipeline is different than that of an operating Utility which consistently replenishes assets to maintain indefinite service. However, a number of considerations and challenges evaluated in that determination are similar to the challenges faced by an operating utility such as FEU. Particularly, issues number 2 and number 6, identified on pages 14 and 15 of the NEB Decision RH 2-2008. In those items, the NEB raises concerns with the process for estimating future abandonment costs as well as the risks of over/under collection.

137.1 Please provide a list of all FEU's assumptions made to estimate negative salvage provisions. Provide in a tabular format with formulas for any calculations, where applicable.

<u>Response:</u>

As indicated in response to BCUC IR 1.136.1, the net salvage percentages recommended in the Gannett Fleming study were based on the "traditional" method of net salvage analysis. The approach outlined in the NEB's Reasons for Decision RH-2-2008, is a significantly different approach and is not as applicable for the type of mass property accounts within the FEU system. The NEB approach is used for the terminal retirement (or abandonment) of pipeline systems or significant and large segments of the systems. At page 8 of the NEB Reasons for Decision RH-2-2008 "Abandon" is defined as "*To permanently cease operations such that the cessation results in the discontinuation of service".* In the circumstances of large interprovincial large diameter pipelines that are wholly dependent on specific sources of supply, the concept of economic life and economic planning horizons form a significant component of the depreciation studies. As such, the concept of the terminal abandonment of the NEB regulated pipelines has been an issue for a number of years. Similar issues do not exist with intra-provincial natural gas distribution and transmission systems. The use of life span dates (or economic life) is not common in the circumstances of natural gas systems such as the FEU system.

As the FEU and Gannett Fleming have not incorporated the concept of economic life into the depreciation study, the calculations as discussed in the RH-2-2008 cannot be made. The FEU have not made any type of detailed engineering-based retirement plan for its system, and therefore have not considered any of the type of issues and assumptions that the NEB's Group

1 pipelines are required to make in order to conform with RH-2-2008. In the response to BCUC IR 1.136.4, Gannett Fleming has provided the assumptions and approximate weighting associated with each of the assumptions for the net salvage percentages recommended in the Gannett Fleming report.

137.2 Please explain what inflation rate was used to estimate negative salvage value.

Response:

As indicated in response to BCUC IR 1.136.1, the net salvage percentages recommended in the Gannett Fleming study were based on the "traditional" method of net salvage analysis. The traditional analysis uses the embedded historic rates of inflation for the estimated net salvage percentage. A specifically determined rate of future inflation is not used within the traditional method of net salvage analysis.

137.3 Please explain if negative salvage value amounts represent the cost to fully dismantle/remove assets.

Response:

For the majority of the FEU's assets such as distribution services and mains, the practice has been to abandon rather than dismantle/remove the pipe, unless there are specific requirements to relocate the pipe. For some assets such as stations/buildings, the retirement costs incurred are for dismantling and removing.

The traditional method of net salvage analysis is developed using the historic trends as the beginning point of the analysis, and assumes that the historic data will be reflective of the historic patterns of dismantlement/removal compared to abandonment in place. Gannett Fleming did not make any adjustment with regard to the dismantlement/removal/abandonment assumptions resulting from historic analysis. The negative salvage amounts provided thus represent estimates of the costs either to dismantle/remove or to abandon, depending upon the nature of the asset.

How has technology innovation been factored into the negative salvage calculation given the useful lives of many assets are over 40 years?

Response:

No. As indicated in the response to BCUC IR 1.136.4, for the asset classes with proposed negative salvage rates, changes in technology have not significantly affected the costs to retire the assets. For example, whether we are removing a main or service, there has not been a significant change in technology that has affected the costs to retire the pipe.

137.5 How do actual salvage costs of pipelines depending on whether pipes are abandoned vs. removed? How has this difference been factored into cost estimates?

Response:

Gannett Fleming notes that the costs of removal are, in most circumstances, higher than the costs of abandonment of pipelines. The traditional method of net salvage analysis as used by Gannett Fleming in this depreciation study, has been based on the historic trend of the FEU to abandon pipelines in most circumstances.

137.6 When an asset is taken out of service and a new asset is placed into service at the same time (i.e. an asset is replaced), how are costs for the replacement split between removal activities and installation activities?

Response:

For most assets, as there usually is time separation between the removal of the existing asset and the construction of the new asset, separate charge numbers are raised to capture the costs for retiring the existing asset and for installing the new asset. For example, for mains and services, separate charge numbers are raised to capture the costs for installing the new asset and for the removal or abandonment.

In the situation where there is little separation in time, such as in the case of meter exchanges where old meters are exchanged with new meters, it is difficult to separate out costs using different charge numbers. Instead, the costs are split between the new asset and the removal costs related to the existing asset based on an allocation. Typically, a residential meter exchange takes approximately 45 minutes to complete including the travel time of technician. The technician charges his/her time including vehicle costs to a single meter exchange order. Based on a review of the activities performed, the Companies allocate 50 percent of the meter exchanges costs to retirement with the remaining 50 percent of the costs attributable to the new meter installed. Other than replacing the existing meter with the new meter, all tasks associated with the meter exchange are assumed to apply equally to the removal and the installation of the meter.

137.7 How will current and future income tax impact negative salvage amounts?

Response:

The FEU understand that "future income tax impact" above is intended to refer to the income tax impact of the future (proposed) treatment of negative salvage, as opposed to the accounting for future income tax (FIT) and have responded to this question accordingly.

Provisions for estimated negative salvage (future removal costs less salvage proceeds) are not deductible for income tax purposes.

Rather, actual removal costs relating to removal activities are deductible for tax purposes in the year incurred. Actual costs relating to installation activities are added to Undepreciated Capital Cost ("UCC") in the year incurred. Actual positive salvage amounts are deducted from UCC or taken into income for tax purposes in the year received depending on the original cost of the asset.

137.8 If FEU underestimates removal costs, does it bear any risk associated with under-collecting or over-collecting funds to complete the removals?

Response:

The process for estimating removal costs that has been proposed by the FEU is consistent with industry practice and is the generally accepted regulatory treatment across North America. Because of the uncertainty associated with estimating removal costs for assets that will be removed from service many years in the future, the proposed process and accounting treatment is appropriate. The proposal recognizes that these removal costs need to be recovered from customers that receive service from the assets. While the amount of future costs are uncertain, the process of re-assessing the adequacy of provisions against actual costs being incurred on an ongoing basis provides both the customer and the shareholder with assurance that there is a reasonable matching of the costs of providing service with customer rates.

The estimating and correction process relies on a large volume of assets and a long period of time over which they retire to offset the difficulties in accurately estimating retirement costs. As a result, the negative salvage provision is similar to deferral account mechanisms, which are often used to capture variances due to uncontrollable costs or costs that are difficult to forecast. Similar to the negative salvage provision, deferral accounts provide benefits as they avoid windfall gains or losses to either the customer or the shareholder. The fact that these removal costs occur in the future and therefore have to be estimated does not change the underlying nature of the costs to be recovered – these costs are for removal and abandonment of assets that have been used to provide utility service. Therefore, these costs are recoverable from customers.

The NEB Decision has some relevance to the FEU but only in terms of general guidelines and principles. These guidelines and principles will not be translated into an actual methodology for recovery of abandonment costs until five years from the date of the Decision. As stated in the preamble to this question, the nature of the removal costs under consideration in the NEB Decision is different than the removal costs in consideration in this Application, and that distinction is important in understanding the issue of any potential for over-collection or under-collection of funds. Of note in that decision:

1. The NEB Decision specifically considers the issue of abandonment, defined as "To permanently cease operation such that the cessation results in the discontinuance of service" and not decommissioning, which is defined as "To permanently cease operation such that the cessation does not result in the discontinuation of service, for example, when a tank is removed from operation on a pipeline and the pipeline continues to operate without the tank". The Panel also noted on Page 42 of the NEB Decision that both deactivation and decommissioning contemplate continuation of system service. Provided service continues, revenue will be generated from the collection of tolls, from which funds should be available to cover these decommissioning costs; and

2. The assets under consideration in the NEB decision are accounted for under a single-unit depreciation method, such that individual assets are tracked along with individual service lives, and therefore individual estimates of the timing and costs of abandonment can be made, and can be compared against the actual costs incurred at the time of abandonment. At that time or likely even in the years before then, an evaluation can be made of the adequacy of the collection for removal costs. As discussed in the

Decision[24], because the ultimate abandonment costs to be incurred will become more certain as the abandonment date nears, adjustments to the amounts collected can be made in the later years to minimize any risk of over- or under-collection.

In contrast, the majority of the FEU's assets are maintained under the mass or group accounting system. The group system 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 group.

An excerpt from the BCUC Uniform System of Accounts helps to illustrate this concept:

> *"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 o f 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. It is not the intention of this classification to require the company to keep record of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated depreciation is subdivided according to the utility department to which applicable, or to each group of gas plant accounts."*

This group accounting practice, which is allowed and followed by the FEU for the majority of assets, does not allow the utilities to "keep record of the accumulated depreciation of each unit of plant". Nor does it allow the utilities to keep record of the negative salvage (removal cost) estimates related to each unit of plant. Since removal estimates are maintained at the asset class (or group) level only, the FEU are unable to determine if they have either over-collected or under-collected removal costs for a specific asset in a specific year. Therefore, for these group accounting assets, the FEU will be unable to determine if over-collections or under-collections exist.

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[24] *"Concerning the risk of underfunded abandonments, the Panel is of the view that over time these risks can largely be mitigated. As discussed in the Framework, there will be appropriate mechanisms in place to review abandonment cost estimates, and the accumulation of funds and growth of funds over time. These regular reviews will also mitigate the over-collection of funds from users, thereby ensuring a responsible approach to funding abandonment. The Panel also recommends that there be appropriate ongoing oversight by the Board of abandonment funding. In addition, the Panel notes that pipeline companies have an incentive to set aside and recover sufficient funds from their users so that they, and their shareholders, are not left with the responsibility for any shortfalls. All of these factors will help mitigate the risks of underfunded or unfunded abandonment."*(Page 35 NEB Decision)

For assets subject to group accounting methodologies, the more appropriate way to address the issue of accuracy of negative salvage forecasts is through regular, periodic reviews and updating of negative salvage rates in conjunction with the updating of the depreciation rates (every 3 to 5 years). Through this process, annual estimates could be compared against updated actual removal costs incurred and any changes can be factored into future estimates.

For those assets that are tracked at an individual service life level, the majority do not attract negative salvage. For any individual assets that do attract negative salvage and that are nearing a decommissioning date, the FEU would expect that the estimates of removal costs would be increasingly accurate as that date of decommissioning nears which would result in minimal over- or under-collection, similar to the expectations articulated in the NEB Decision. However, even for these assets, the FEU draw a distinction in that the assets that are individually tracked remain part of the gas system as a whole, and there is no expectation that the gas system itself will be abandoned such that operations cease. Therefore, even for these individually tracked assets, it is not appropriate that the shareholder be at risk for such cost estimates. This distinction is important in understanding the implications of the NEB Decision.

In summary, the FEU acknowledge that the estimates required to determine the future removal costs are, by their nature, uncertain. Given this, the risk of under or over collecting for individual assets is real; the group system of accounting in combination with negative salvage provisions is designed to reduce these uncertainties by "averaging out" the retirement experience of individual assets over a long period of time. It is in the interests of both the shareholder and the ratepayers to treat the costs as we have proposed. Under the proposed process, the shareholder does not recover any windfall gains and customers are only paying for the prudently incurred cost of decommissioning assets.

137.9 If an asset is retired before the end of its estimated remaining useful life (for accounting purposes), would FEI be prepared to seek commission approval for recovery of either i)salvage amounts which exceed amounts collected from customers or ii)actual salvage costs which exceed the estimated costs? If amounts for similar assets could be aggregated, annually, would this impact the answer?

Response:

For the everyday removal costs that are incurred in the ordinary course of business, the FEU would not be prepared to seek approval of differences in estimated removal costs. Firstly, as discussed in response to BCUC IR 1.137.8, it would not be possible to determine these differences on an individual asset basis. Secondly, the FEU would be unable to efficiently run their utility operations with this additional step for approval of everyday transactions. The answer would be the same even if the costs were aggregated annually, as the FEU believe that the appropriate time to review the negative salvage rates and costs is through the rate setting process in revenue requirement applications. Also as discussed in response to BCUC IR 1.137.8, the FEU believe that a process of regularly reviewing and updating negative salvage estimates achieves the most appropriate balance of ensuring negative salvage estimates are as accurate as possible while allowing the utilities to continue to maintain the integrity of the system for the benefit of customers.

For dispositions of property outside the ordinary course of business, under the *Utilities Commission Act*, the FEU are required to seek Commission approval as follows:

> *"Restraint on disposition*
>
> *52 (1) Except for a disposition of its property in the ordinary course of business, a public utility must not, without first obtaining the commission's approval,*
>
> > *(a) dispose of or encumber the whole or a part of its property, franchises, licences, permits, concessions, privileges or rights, or*
> >
> > *(b) by any means, direct or indirect, merge, amalgamate or consolidate in whole or in part its property, franchises, licences, permits, concessions, privileges or rights with those of another person.*
>
> *(2) The commission may give its approval under this section subject to conditions and requirements considered necessary or desirable in the public interest."*

In accordance with this requirement, the FEU would expect to seek Commission approval for disposition of assets that are not in the ordinary course of business, and as part of that request would be willing to provide to the Commission both the amount of removal costs that had been collected for that specific asset if applicable, and the estimated costs of removal at the time. The FEU would at the same time seek approval of the regulatory treatment of the transaction.

138.0 Reference: Depreciation Study

Exhibit B-1, Application, Appendix E-1, p.II-33

Reporting

138.1 If the use of negative salvage amounts are approved, would FEI be prepared to provide annually, to the Commission, a report that would detail negative amounts collected for the year as well as asset retirement information including:

a) Number of total assets retired in the year and total retirement costs for the year, a calculated average retirement cost per asset and the total collected negative salvage amount (as of January 1, 2012).

b) Number of total assets retired in the year by asset class and total retirement costs for the year by asset class, a calculated average retirement cost per asset class and the total collected negative salvage amount for the asset class(as of January 1, 2012).

c) A list, for each asset class, of total assets retired in the year for all assets retired before the end of the assets remaining economic useful life.

d) A list of any individual retirements for which retirement costs were higher/lower than the average retirement cost of the asset class by +/- 15%.

e) A list of all assets, by asset class, of all assets fully depreciated, but are still in service with an estimate of remaining actual asset service life.

f) A detailed list of all retirements and costs, by asset class, during the year if requested by the Commission.

Response:

As indicated in the response to BCUC IR 1.143.5, the FEU support annual reporting of annual actual results and provisions by asset class to monitor their reasonableness over the near-term with complete reviews of estimates and assumptions regularly over a longer period (i.e. three years) to factor in trends that evolve over time.

The FEU re-emphasize that the majority of our assets are maintained under the mass or group accounting system which simplifies the process of tracking a large asset system with many small components with small relative values. However, this group accounting practice does not allow the utilities to keep records and report at the individual asset level for accumulated depreciation or negative salvage (removal cost) estimates. As a result, reporting retirements at the asset level and any associated gain or loss cannot be done as it is contrary to the group system of accounting in place.

The FEU believe that an annual report by asset class showing negative salvage collections, actual removal costs incurred, and assets retired would provide value.

139.0 Reference: 442.00 LNG Gas – Structures

Exhibit B-1, Application, Appendix E-1, p.II-33

Negative Salvage

"Account 442.00 – LNG Gas - Structures - This account has very limited retirement and net salvage transaction history. Therefore the net salvage percentage of -10% was based on the professional judgment of Gannett Fleming. As there is only limited experience throughout Canada of regulated LNG storage facilities, a peer analysis for this account was not completed. As part of the last depreciation study completed by Gannett Fleming, a site tour of the LNG facility was conducted. Additionally as part of this current depreciation study, a site tour of the facility currently under construction was completed, providing a prospective of the type of structures required for these facilities. Gannett Fleming views that upon retirement of the LNG facilities, a significant cost of removal will be required for the LNG structures and that a net salvage percentage of at least -10% is appropriate. A net salvage percentage of -10% was recommended in the last depreciation study, and Gannett Fleming recommends that, at this time, the -10% be continued. Gannett Fleming notes that the net salvage percentage may need to be increased in future studies, once this account begins to experience more retirement activity."

139.1 Please confirm that the only basis for the estimated salvage rate of -10% was the professional opinion of Gannet Fleming?

Response:

The net salvage percentage was based on the professional opinion of Gannett Fleming. The professional opinion of Gannett Fleming was based on the physical site tours conducted at both of the FEU LNG facilities as well as LNG facilities in Quebec. In the view of Gannett Fleming, the physical LNG structures are very similar in nature to a number of manufacturing plants in the oil and gas industry. Gannett Fleming views that the costs to retire any assets within the LNG facility will be extremely labour based, and will likely require costs of retirement far in excess of -10 percent. However, given the limited retirement history of these facilities, a request in excess of -10 percent would be premature at this time.

Gannett Fleming notes that the use of professional judgement in the development of net salvage estimates is a long-standing accepted method in circumstances where limited retirement data is available, and when it is premature to undertake a detailed engineering based cost estimate. The incorporation of professional judgement has been accepted in a number of regulatory jurisdictions across Canada. For example, the historic net salvage percentages approved by the Alberta Utilities Commission incorporate net salvage percentages that include the use of professional judgement for both AltaGas Utilities and ATCO Gas.

139.2 Did anyone review the work of Gannet Fleming and provide an independent opinion as to the reasonability of this estimate?

Response:

Gannet Fleming's opinion is independent and there is no need for a second independent party review of Gannett Fleming's estimates.

Gannett Fleming is a large ISO 9001 certified Engineering firm, with a staff of over 2,000 employees. One of the critical ISO requirements for Gannett Fleming is that all professional recommendations are subjected to an internal independent third-party review, where the recommendations are internally vetted. In the specific circumstances of the net salvage recommendations related to the LNG facilities, the recommendations of Mr. Kennedy were reviewed by Mr. John Spanos within the firm's Harrisburg Pennsylvania office, prior to inclusion in the depreciation study. Mr. Kennedy's and Mr. Spanos' Curriculum Vitae are provided in Attachment 139.2.

Further, as in the past, the FEU have worked actively with Gannett Fleming to complete the depreciation study. In addition to providing the financial data requested by Gannett Fleming, the FEU review the recommended depreciation rates for accuracy, reasonableness and applicability to its assets.

139.3 Given the significance of the estimate and the requirement to apply professional judgement, would it be prudent that all negative salvage estimates for which no clear, useable, historical data and very limited experience in Canada, would a second opinion be useful as a review of the reasonability of the estimate? If not, what other techniques were used to corroborate the assumptions made by Gannett Fleming?

Response:

Please refer to the response to BCUC IR 1.139.2.

139.4 Is there another regulated Canadian LNG facility for which negative salvage rates are being applied?

Response:

Yes. Gaz Metro has an approved depreciation rate that includes a net salvage percentage of -29 percent related to LNG facilities. Gaz Metro has a current application before the Regie de l'energie du Quebec for an increase in this net salvage percentage to -43 percent. This application is still under review. Gannett Fleming also understands that the Union Gas LNG facilities have an approved net salvage percentage of -34 percent. Gannett Fleming's understanding is that the other utilities' negative salvage rates are based on engineering review of their specific circumstances.

Gannett Fleming's recommended rate of -10 percent for the FEU represents a conservative estimate recognizing that the negative salvage rate may need to be increased in future studies after there is more experience with retirement activities for this asset category.

139.5 What are the negative salvage rates for all other Canadian LNG facilities subject to regulation?

Response:

Please refer to the response to BCUC IR 1.139.4.

139.6 How likely is it that an LNG site will be fully decommissioned without recovery of materials or other items which will be reused for similar functions in the future? Have these factors been taken into consideration?

Response:

Gannett Fleming has considered that there would be some recovery of material that may be sold to third parties or sold for scrap value. However, in the professional view of Gannett

Fleming, the costs of the labour associated with the decommissioning of the plant and removal of the facilities will far outweigh any potential gross salvage value. In part, the consideration of this potential salvage value caused Gannett Fleming to recommend only a very moderate net salvage percentage.

140.0 Reference: 466.00 LNG Compressor Equipment

Exhibit B-1, Application, Appendix E-1, p.II-40

Negative Salvage

Account 476.00 – NGV Fuel Equipment - This account has not occurred any retirement activity since the year 2000, and no net salvage transactions. As the investment in this account relates to equipment that will be labor intensive to remove, Gannett Fleming views that a net salvage percentage that result in excess of $100,000 will be required. Additionally, the retirement booked in the year 2000, may have physical plant to remove for the investment dollars have been previously retired. Therefore, only a small amount of investment remains in this account, which will be the basis for the accrual of all of the required cost of removal expenditures. It is the view of Gannett Fleming that a net salvage percentage of -20% is required to collection of the funds required for the removal of the physical plant.

140.1 Does the local Gannett Fleming have significant experience with NGV fuel equipment and other alternative energy assets, such as Biomethane asset? If so, please list the alternative energy experience of the Gannett Fleming professionals utilized on this engagement.

Response:

The FEU note that NGV fuel equipment and Biomethane assets are part of the natural gas business, and not alternate energy assets as described in the question.

Further, Gannett Fleming study did not provide the recommended depreciation or negative salvage rates for the biomethane upgrader assets and the new NGV fueling service assets included in this Application. The Gannett Fleming study evaluated assets in place as at December 31, 2009, which did not include the biomethane upgrader or new NGV fueling service assets. In this Application, for both the NGV fueling service assets and the biomethane upgrader assets, FEI has applied the depreciation rates as included in the applications for those services filed on December 1, 2010 and June 8, 2010 respectively. Please refer to BCUC IR

1.140.2 for a discussion on the depreciation and salvage rates pertaining to the new CNG and LNG service assets.

In relation to Gannett Fleming's experience with the determination of the rates that were included in the depreciation study for existing NGV assets, Gannett Fleming has completed studies on behalf of the following Canadian clients that have included NGV assets:

- ATCO Gas
- Enbridge Consumers Gas
- Manitoba Hydro (Centra Gas Manitoba)
- Gaz Metro
- SaskEnergy

Additionally, Mr. Spanos from the firm's Harrisburg Pennsylvania office reviewed the recommendations in the Gannett Fleming report. Mr. Spanos has completed a number of studies on behalf of US based clients that have also included recommendations regarding NGV equipment.

140.2 Has this estimate of negative salvage been included in cost estimates for the Waste Management CNG Service Agreement included in the application filed December 1, 2010 seeking approval for the CNG and LNG S fueling service? If not, were expected future retirement costs included in the cost estimates?

Response:

No, a -20 percent estimate of negative salvage was not included in the cost estimate for the Waste Management CNG Service Agreement. Yes, future retirement costs were included in the cost estimates for the Waste Management CNG Service Agreement.

The depreciation rates proposed in the CNG-LNG Application, and correspondingly reflected in this Application for those assets, are based on the estimated useful life provided by engineering sources. In the determination of the NGV fueling station cost of service and rates, FEI applied the approved treatment of net salvage in accordance with Commission Order No. G-141-09. That is, a provision for estimated net negative salvage was not included in the depreciation rate and forecast removal costs are included as an expense in the year in which they occur. As provided in the CNG and LNG Service Application, response to BCUC Confidential IR 1.22.1

and 1.22.2 (Exhibit B-3), in the case of the ten year WM Agreement the estimated removal costs pertaining to site restoration were forecast to occur in year twenty-one of the analysis, or 2031. Therefore, although included in the cost estimate, in accordance with approved regulatory accounting practices in place for 2010, a provision for removal costs was not included in the Waste Management fueling station contract rate applicable for years 2011-2020.

The Gannett Fleming study did not evaluate the assets contemplated in the CNG-LNG Application, more specifically the WM Agreement, or the Biomethane upgrader assets because the study evaluated assets in place as at December 31, 2009. As such, the recommended depreciation and negative salvage rates for Account 476 NGV Fuel Equipment included in the Gannet Fleming depreciation study are not reflective of the CNG-LNG assets contemplated in the CNG-LNG Application or the WM Agreement.

In conjunction with future revenue requirement applications, updates to the depreciation study will include depreciation and negative salvage rates that reflect the new CNG-LNG fueling service assets and Biomethane upgrader assets.

140.3 Is this description of asset reclamation costs consistent with the information presented in the proceeding seeking approval for the NGV fueling services?

Response:

No. Please refer to BCUC IR 1.140.2.

140.4 How would the NPV of the Waste Management fueling station project be impacted by the inclusion of negative salvage value?

Response:

Please refer to BCUC IR 1.140.2.

The NPV of the Waste Management fueling station project would not have been impacted by the inclusion of negative salvage value because the fueling station rate is set to recover the cost of service of the agreement term. That is, the fueling station rates for CNG and LNG fueling service are set so that the present value of the revenues collected from the rate(s) equal the present value of the cost of service that is applicable to the term of the agreement. Including the negative salvage would result in an increase in revenue to offset the increase in cost of service, all else equal.

The fueling station rate applicable to the Waste Management Agreement reflects the approved regulatory accounting practices in place as at 2010. Subsequent changes to any accounting policy will impact the actual cost of service incurred pertaining to the Waste Management fueling station project and may result in a variance from the forecast cost of service used to derive the fueling station rate.

140.5 If approved, will negative salvage value be included in the costs analysis of all future CNG and LNG service agreements?

Response:

Yes. FEI will continue to base its cost analysis of CNG and LNG service agreements on approved regulatory accounting policies. However, as discussed in BCUC IR 1.140.2, FEI notes that the negative salvage percentage of -20 percent did not include a consideration of new CNG and LNG assets. As such, if the proposed regulatory treatment of negative salvage is approved, FEI will determine the applicable negative salvage percentage on an agreement by agreement basis, using the forecast asset and retirement costs.

141.0 Reference: 466.00 Heavy Work Equipment

Exhibit B-1, Application, Appendix E-1, p.II-46

Negative Salvage

Account 485.10 – Heavy Work Equipment – Interviews with operational and accounting staff have indicated that net salvage proceeds related to the sale of heavy work equipment have only been separately recorded since 2008. Therefore a detailed database with historic sales transactional is not available. Prior to 2008, the trade-in value of work equipment was offset against the purchase cost of the replacement equipment. As such, Gannett Fleming has relied on the comments of the fleet management group, and on the peer group in the development of the net salvage recommendations.

A review of peer natural gas utilities has indicated the following:

- ATCO Gas – 30%
- Enbridge Gas Distribution – 25%
- AltaGas – 20%
- Manitoba Hydro/Centra Gas Manitoba- 20%
- SaskEnergy – 20%

Interviews with the Fleet Management group indicated an expectation of positive salvage proceeds of at least 15%. Although this is lower than the peer group experience, given the low volume of sale transactions, Gannett Fleming recommends the continuation of the 15% net salvage percentage.

141.1 Please confirm that the only information utilized to estimate this account was discussions with FEU Staff?

Response:

The indications provided by the Fleet Management group were the primary consideration in the recommended net salvage percentage. Also considered was peer industry experience. However, Gannett Fleming notes that if the gross salvage proceeds are shown to exceed the recommended 15 percent, the amount of the excess will be used to lower the depreciation rate in future studies.

141.2 How many asset retirements have occurred in this account since 2008?

Response:

The FEU had a total of two asset retirements for this asset class since 2008 with total net salvage of approximately $500.

141.3 What was the actual net salvage amount on each of those retirements?

Response:

Please refer to the response to BCUC IR 1.141.2.

141.4 Before 2008, were any recovery amounts experienced on this asset class grouped outside of the asset account (i.e. were not netted against the asset through subaccounts for either accumulated depreciation or other losses)? If yes, to which general ledger account were the journal entry credit amounts recorded?

Response:

No proceeds were grouped outside of the asset accounts. Prior to 2008, all recovery amounts experienced in this asset class were offset against the purchase cost of the replacement equipment (trade-in value) or applied to accumulated depreciation (salvage value) within the asset class.

141.5 If management had an expectation of "at least 15%" that seems to indicate that 15% is the minimum amount expected? What was the maximum proceeds amount expected by FEU staff?

Response:

The FEU do not have a maximum amount expected.

Salvage proceeds realized on the disposal of heavy work equipment vary and are influenced by a number of factors including:

- age or model of equipment;
- physical condition of equipment;
- advancement in technology;
  - if new equipment has new productivity features, older equipment will have lower market value; and
- after-market for used equipment.

141.6 What is the most likely amount expected, not just the minimum amount, based on those discussions?

Response:

The FEU agree with using the 15 percent recommended by Gannett Fleming as a reasonable and conservative estimate of negative salvage for this heavy work equipment asset class, given the low volume of sales transactions.

141.7 Why was the most conservative estimate of proceeds on disposition applied to this asset class?

Response:

Please refer to the response to BCUC IR 1.141.6.

142.0 Reference: 466.00 Heavy Mobile Equipment

Exhibit B-1, Application, Appendix E-1, p.II-47

Negative Salvage

> Account 485.20 – Heavy Mobile Equipment - Interviews with operational and accounting staff have indicated that net salvage proceeds related to the sale of heavy mobile equipment have only been separately recorded since 2008. Therefore a detailed database with historic sales transactional data is not available. Prior to 2008, the trade-in value of the equipment was offset against the purchase cost of the replacement equipment. As such, Gannett Fleming has relied on the comments of the fleet management group, indicating an expectation of 10% upon resale. This equipment is not typically separated in the circumstances of the peer group of companies; therefore a peer analysis was not undertaken. Based on the comments of the fleet management group, the continuation of the 10% net salvage percentage is recommended.

142.1 Please confirm that the only information utilized to estimate this account was discussions with FEU Staff?

Response:

The indications provided by the Fleet Management group were the primary consideration in the recommended net salvage percentage. Also considered was peer industry experience. However, Gannett Fleming notes that if the gross salvage proceeds are shown to exceed the recommended 10 percent, the amount of the excess will be used to lower the depreciation rate in future studies.

142.2 How many asset retirements have occurred in this account since 2008?

Response:

The FEU's records up to May 31, 2011 show that there have been three retirements for this asset class since 2008 with approximately $28,000 in salvage proceeds realized. The assets retired were:

- Backhoe in 2008 with salvage proceeds of $24,771;
- Forklift in 2011 with salvage proceeds of $3,251; and
- Bobcat in 2008 with no salvage proceeds.

142.3 What was the actual net salvage amount on each of those retirements?

Response:

Please see the response to BCUC IR 1. 142.2.

142.4 Before 2008, were any recovery amounts experienced on this asset class grouped OUTSIDE of the asset account (i.e .were not netted against the asset through subaccounts for either accumulated depreciation or other losses)? If yes, to which general ledger account were the journal entry credit amounts recorded?

Response:

No proceeds were grouped outside of the asset accounts. Prior to 2008, all recovery amounts experienced in this asset class were offset against the purchase cost of the replacement equipment (trade-in value) or applied to accumulated depreciation (salvage value) within the asset class.

142.5 Is this equipment normally included in Heavy Work Equipment by the Companies? If not, please explain which class this equipment is typically grouped with?

Response:

Heavy mobile equipment has been tracked separately from heavy work equipment as it has a different useful life. Account 485.10 Heavy Work Equipment includes equipment such as an air compressor, generator, shoring cage and welding machine, whereas account 485.20 Heavy Mobile Equipment includes mobile equipment such as backhoes and bulldozers.

142.6 If so, does this indicate that other utilities experience recoveries of between 20-30% on this equipment?

Response:

It is difficult to ascertain as the other utilities' experience is based on a combined asset category for heavy work equipment and heavy mobile equipment. Given the limited retirement data for this asset class (i.e. prior to 2008, the trade-in value of the equipment was offset against the purchase cost of the replacement equipment), the recommended initial 10 percent negative salvage rate is reasonable. Gannett Fleming notes that if the gross salvage proceeds are shown to exceed the recommended 10 percent, the amount of the excess will be used to lower the depreciation rate in future studies.

143.0 Reference: Analysis of Asset Retirement Losses

Exhibit B-1, Application, Appendix E-2, p.9-13

Estimation Process

As negative salvage is an advanced customer billing to recover the Future (i.e. not yet incurred) costs to take an asset out of service, it involves significant estimation that considers many factors such as timing, future costs, inflation, technology changes and future environmental considerations, etc. Further, if a Utility does not estimate or track the provision accurately, managing the salvage collections could prove difficult. Also, ensuring that all funds collected from customers in advance will be available to take assets out of service as needed is imperative

143.1 Please explain, in full the estimation process for negative salvage provisions. Will the process completely provided by a third party or will some of the process be managed in-house?

Response:

Please refer to the response to BCUC IR 1.136.1 for an explanation of the estimation process for negative salvage provisions.

The preamble to this series of questions, which appears to be a summary prepared by Commission Staff, notes some considerations regarding the approach to recovery of negative salvage or removal costs. The primary issue referenced in the preamble is the accuracy of the estimating process that is developed. The FEU have adopted a reasonable estimating process based on historical results and have tracked funds separately by asset class. While it is not reasonable to expect that estimates will be 100 percent accurate, a reasonable estimating process is more desirable than the alternative of not collecting removal costs until the assets are removed from service at all. As no funds would be collected from customers during the life of the asset, customers at the time of retirement would be required to bear the entire cost of salvaging the assets, which would create issues of intergenerational equity between customers.

The preamble also notes a concern with the availability of funds at the time assets are taken out of service. This concern may be material in dedicated or single asset situations where there are significant removal or abandonment costs at or near cessation of operations (abandonment), with the legal entity unable to fund these costs. The FEU note that collecting removal costs at the time the assets are removed from service does not address the issue of ensuring that funds will be available to take assets out of service as needed. For the FEU, the relative size of the asset retirement in a given year is expected to be manageable without the need for specific consideration of the availability of funds.

The FEU's recommended treatment provides the best balance in addressing the issues identified in the preamble, in that it distributes costs to ratepayers equitably over time, and improves utility accountability for removal costs collected from ratepayers through tracking provisions separately by asset class, while achieving an appropriate balance with respect to administrative costs relating to implementation, maintenance and tracking. This approach combined with the regular review and updating of depreciation and negative salvage rates and annual reporting of results is the most appropriate solution for the types of ongoing removal costs that the FEU incur.

143.2 Given the significance of the negative salvage estimates, what additional steps will be taken to ensure that senior management are satisfied with the recommended rates?

Response:

As indicated in the response to BCUC IR 1.136.14, the FEU believe that the process we have undertaken to develop the current proposed negative salvage rates is reasonable and appropriate. The FEU are following a common industry practice for utilities where utility staff works with an external depreciation and negative salvage specialist to determine its 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.

Consistent with industry practice, the FEU recommend that reviews of depreciation and negative salvage estimates be performed regularly (i.e. every 3 to 5 years) in order to adjust the rates as required to ensure their reasonableness.

143.3 What documentation will FEU obtain from a third party service provider to ensure that there is adequate and appropriate evidence, and that the estimation process applied sufficient rigor, objectivity, data analysis and verification of historical results to make an appropriate recommendation?

Response:

Please refer to responses to BCUC IRs 1.136.1, 1.136.2 and 1.136.14.

143.4 What documentation has been provided by Gannett Fleming to FEU, other than the report, to support the estimations of negative salvage provisions included in this Application?

Response:

Please refer to responses to BCUC IRs 1.136.1 and 1.136.3.

143.5 Does FEU intend to test negative salvage provisions on a regular basis, presumably annually, to compare actual results experienced each year against provisions made in the last depreciation study?

Response:

Please refer to the response to BCUC IR 1.143.2.

Consistent with industry practice, the FEU plan to review the depreciation and negative salvage estimates regularly in the Application (Exhibit B-1), Appendix E-1, on page I-5 of Gannett Fleming study, Gannett Fleming recommends complete depreciation studies be performed every 3 to 5 years to re-evaluate assumptions) in order to adjust the rates as required to ensure their reasonableness.

Annual reporting of annual actual results against provisions is reasonable and provides for comparative review of the estimates vs. actuals over the short term. However, the reasonableness and validity of estimates used can be better tested over a longer period (i.e. 3 to 5 years) where trends can be observed and adjustments made.

143.6 What internal controls have been designed to detect any negative salvage provisions that are inconsistent with experienced results on an annual basis?

Response:

Please refer to the response to BCUC IR 1.143.5.

143.7 As the negative salvage calculation is based on a notional estimate, how many years will it be before the estimate is tested?

Response:

Please refer to the response to BCUC IR 1.143.5.

143.8 Does FEU intend to rely on Commission approval to utilize negative salvage rates for financial reporting or will FEU provide to their financial reporting external auditors supporting schedules needed to perform standard audit tests to review management estimating process as required under generally accepted auditing standards? If so, please describe the schedules FEU intends to provide to its external auditors in the case that negative salvage is accepted by the Commission.

Response:

Under US GAAP, the FEU intend to rely on Commission approval to record negative salvage recoveries and provisions for financial reporting under the provisions of Accounting Standards Codification 980 Accounting for the Effects of Certain Types of Regulation. The FEU would expect to provide the auditors sufficient information related to the collection of negative salvage and the actual spending on retirements to support their audit opinion on the amounts recorded in the income statement and balance sheet (likely a continuity schedule and support for any transactions selected for testing). Additionally, the FEU would provide the external auditors with a copy of the report from Gannett Fleming supporting the negative salvage rates and any Commission related order on the treatment of negative salvage. For financial reporting purposes, the FEU expect to record the net amount as a regulatory asset or liability.

143.9 Has FEU made a forecast of the net negative salvage costs it is expected to incur over the next 20 years that is based on a bottom up, activity based engineering estimate as well as on a forecast of asset replacements?

Response:

No. As indicated by Gannett Fleming's response to BCUC IR 1.136.1, noting the following:

> ".... *As the investment in most mass property accounts is normally comprised of a variety of asset sizes, attained ages, technologies, and in the circumstances of FEU have included plant physically located throughout the province with varying degrees of net cost of removal,* ***it is difficult and not economically prudent to develop a detailed engineering estimate for the removal of all the plant that is currently in service*** *such as is required by the NEB Decision RH-2-2008 for the federally regulated large diameter transmission pipelines. As such, the use of the historic ratio of net salvage costs to the original cost of plant retired is appropriate and used as one indicator of the current estimated cost of removal."*

143.10 If the answer to the previous question is "yes", then please provide the forecast, by year, of net negative salvage costs that FEU is expected to incur over the next 10 years.

Response:

Please refer to response to BCUC IR 1.143.9.

143.11 Should FEU be required to provide to the Commission on a regular basis, an updated forecast of net negative salvage costs that based on engineering estimates and a forecast of asset replacements?

Response:

Please refer to the responses to BCUC IRs 1.143.5 and 1.143.9.

143.12 Should FEU be required to provide to the Commission on a regular basis, a report of the net negative salvage balances, along with the removal costs incurred and any proceeds on disposal?

Response:

The FEU would expect to include the continuity of negative salvage provisions by asset class (opening balance, plus amounts collected from customers, less actual removal costs incurred equals closing balance) as part of its annual reporting to the Commission.

Please refer to the response to BCUC IR 1.143.5 where the FEU indicate annual reporting of annual actual results against provisions is reasonable and provides for comparative review of the estimates vs. actuals over the short term. However, the reasonableness and validity of estimates used can be better tested over a longer period (i.e. 3 to 5 years) where trends can be observed and adjustments made.

144.0 Reference: Exhibit B-1, Tab 7.1, Schedules 1, 61, 62

Tab 7.2, Schedules 1, 61, 62

Tab 7.3, Schedules 1, 61, 62

Tab 7.4, Schedules 1, 61, 62

Negative Salvage and the Revenue Deficiency

144.1 Please complete the following table:

For 2012	Mainland	Vancouver Island	Whistler	Fort Nelson
Provision for Net Negative Salvage ($000)				
Income Tax on Provision ($000)				
Total impact to Revenue Requirement ($000)				
Revenue Deficiency from Schedule 1 ($000)				

Response:

This response also addresses BCUC IR 1.144.2.

Note that the impact to revenue requirement in the table above reflects only the provision for negative salvage and corresponding income tax impact for each year. This high level analysis will exclude the minor rate base impacts of the negative salvage provision and estimated removal costs as well as the revenue requirement reduction that results from the deduction of actual removal costs for income tax expense purposes.[25]

Since an estimate of the actual removal costs to be incurred in the year was already included in the determination of rates for 2011, the revenue deficiency related to the negative salvage provision is calculated by comparing the negative salvage provision in 2012 ($16,198 for Mainland per table below) to the removal cost provision embedded in 2011 delivery rates ($11,290 for Mainland per table below). This amount needs to be grossed up for taxes; therefore the total revenue requirement impact is equal to the pre-tax removal cost provision divided by 75% (1- tax rate). The cumulative 2013 impact has also been provided in the tables below and is determined in the same manner as the 2012 impact (that is, by comparing to the removal provision embedded in 2011 delivery rates).

[25] Please refer to Section 7, Schedules 34 and 35; removal cost provision (included in Line 3) is added back and actual removal costs incurred that year are deducted (Line 18) in the determination of accounting income after tax.

For 2011 Approved	Mainland	Vancouver Island	Whistler	Fort Nelson
Provision for Net Negative Salvage ($000)	$ 11,290	$ 344	$ 5	$ -
Income Tax on Provision ($000)	$ 4,071	$ 115	$ 2	$ -
Impact to Revenue Requirement ($000)	$ 15,361	$ 459	$ 7	$ -

For 2012	Mainland	Vancouver Island	Whistler	Fort Nelson
Provision for Net Negative Salvage ($000)	$ 16,198	$ 3,915	$ 80	$ -
Income Tax on Provision ($000)	$ 5,399	$ 1,305	$ 27	$ -
Impact to Revenue Requirement ($000)	$ 21,597	$ 5,220	$ 107	$ -
Revenue Deficiency from Schedule 1 ($000)	$ 4,908	$ 3,571	$ 75	$ -
Revenue Deficiency from Schedule 1, Tax Expense Impact ($000)	$ 1,636	$ 1,190	$ 25	$ -
Total Revenue Deficiency from Schedule 1, ($000)	$ 6,544	$ 4,761	$ 100	$ -

For 2013, Cumulative	Mainland	Vancouver Island	Whistler	Fort Nelson
Provision for Net Negative Salvage ($000)	$ 16,743	$ 4,046	$ 82	$ -
Income Tax on Provision ($000)	$ 5,581	$ 1,349	$ 27	$ -
Impact to Revenue Requirement ($000)	$ 22,324	$ 5,395	$ 109	$ -
Revenue Deficiency from Schedule 1 ($000)	$ 5,453	$ 3,702	$ 77	$ -
Revenue Deficiency from Schedule 1, Tax Expense Impact ($000)	$ 1,818	$ 1,234	$ 26	$ -
Total Revenue Deficiency from Schedule 1, ($000)	$ 7,271	$ 4,936	$ 103	$ -

144.2 Please complete the following table:

For 2013	Mainland	Vancouver Island	Whistler	Fort Nelson
Provision for Net Negative Salvage ($000)				
Income Tax on Provision ($000)				
Total impact to Revenue Requirement ($000)				
Revenue Deficiency from Schedule 1 ($000)				

Response:

Please refer to BCUC IR 1.144.1.

145.0 Reference: Exhibit B-1, Application, pp. 326-327; Tab 7.5, Schedules 32, 33

Negative Salvage

Schedules 32 and 33 show provisions for removal costs in 2012 and 2013 of $13,247 thousand and $13,586 thousand, respectively.

145.1 What were the actual removal costs incurred by FEU between 2005 and in 2011?

Response:

Based on the FEU's capital expenditure records, below is a summary of the actual removal costs incurred between 2005 and 2011. Please note that higher removal costs incurred in Whistler for 2009 – 2010 were due to the disposition of propane assets.

Summary of Removal Costs ($000)

Utility	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Projection
Mainland	4,522	6,211	6,350	7,422	7,997	11,909	11,290
Vancouver Island	116	199	506	504	624	790	344
Whistler	-	10	6	5	166	221	5
Ft. Nelson	5	4	6	9	23	7	-
Total	4,644	6,424	6,868	7,941	8,810	12,927	11,639

145.2 What portion of the removal costs in 2010 and 2011 are attributed to the removal or deactivation of mains?

Response:

Below is a summary showing the portion of removal costs in 2010 and 2011 attributed to the abandonment or, in rare instance, removal of mains. This activity is directly related to and proportional to the expenditure for main replacements due to integrity concerns or third-party requests. The percentages remain relatively similar through the forecast period for Mainland; the 2011 projection and 2012 - 2013 forecasts for FEVI are anticipated to be higher as Vancouver Island is forecasting an increase in main replacements. As removal costs are relatively immaterial for Whistler and Fort Nelson, no projections have been provided for 2011.

Percentage of Removal or Deactivation Costs Attributable to Mains ($000)

Utility	2010 Actual	2011 Projection
Mainland	4%	4%
Vancouver Island	9%	15%
Whistler	0%	0%
Ft. Nelson	0%	0%

145.3 What is the average cost per main removal or deactivation?

Response:

Provided below is a summary of the FEU's main removal costs based on the latest 3 years of capital expenditures. The calculated average per metre of main removal is approximately $31 per metre of main retired.

2008-2010 Average

	2008	2009	2010	Total
Cost	643,228	790,115	511,930	1,945,273
Meters of Main	14,761	18,462	30,347	63,570
Average	43.58	42.80	16.87	30.60

145.4 What portion of the removal costs in 2010 and 2011 are attributed to the removal or deactivation of services?

Response:

Below is a summary showing the portion of removal costs in 2010 and 2011 attributed to the removal or deactivation of services.

Percentage of Removal or Deactivation Costs Attributable to Services ($000)

Utility	2010 Actual	2011 Projection
Mainland	75%	86%
Vancouver Island	33%	16%
Whistler	2%	100%
Ft. Nelson	0%	0%

145.5 What is the average cost per service removal or deactivation?

Response:

Provided below is a summary of the FEU's service removal costs based on the latest 3 years of capital expenditures. The calculated average is approximately $1,378 per service retirement.

2008 - 2010 Average

	2008	2009	2010	Total
Cost	5,534,151	5,216,677	9,125,675	19,876,503
Jobs	4,246	4,208	5,972	14,426
Average	1,303	1,240	1,528	1,378

145.6 What portion of the removal costs in 2010 and 2011 are attributed to the removal of meters?

Response:

Below is a summary showing the portion of removal costs in 2010 and 2011 attributed to the removal of meters.

Percentage of Removal or Deactivation Costs Attributable to Meters ($000)

Utility	2010 Actual	2011 Projection
Mainland	19%	9%
Vancouver Island	35%	51%
Whistler	3%	0%
Ft. Nelson	0%	0%

145.7 What is the average cost per meter removal?

Response:

Provided below is a summary of the FEU's Meter removal costs based on the latest 3 years of capital expenditures. The calculated average is approximately $38 per meter retirement and includes the labour costs to remove the existing meter from the customer's premise.

2008-2010 Average

	2008	2009	2010	Total
Cost	865,586	1,332,135	2,500,177	4,697,898
No. of meters retired	27,064	29,219	67,503	123,786
Average	31.98	45.59	37.04	37.95

145.8 Were any costs incurred due to a customer request?

Response:

Provided below is a summary of the FEU removal costs from 2008-2010. For Mains and Meters, the majority of removal costs result from company initiated requests. For Services, the majority of removal costs are incurred for customers' requests for abandonments.

As clarified in the response to BCUC IR 1.153.1, in accordance with the T&Cs, the FEU do not charge a customer for retirement or abandonment of a pipeline that is removed from service.

However, the FEU do charge a customer who wants to relocate or alter a Service Line which will be continuing in-service.

2008 - 2010 Average - Mains ($000)

	2008	2009	2010	Total	Percentage
Customer	8	1	-	8	0%
Company	792	832	851	2,476	100%
Total	800	833	851	2,484	100%

2008 - 2010 Average - Services ($000)

	2008	2009	2010	Total	Pecentage
Customer	4,999	4,665	5,360	15,023	76%
Company	535	552	3,766	4,853	24%
Total	5,534	5,217	9,126	19,877	100%

2008 - 2010 Average - Meters ($000)

	2008	2009	2010	Total	Percentage
Customer	164	124	139	426	8%
Company	942	1,410	2,351	4,703	92%
Total	1,106	1,533	2,490	5,129	100%

145.9 Please explain the reasons for any increase to the forecast removal costs for 2012 and 2013 as compared to the actual costs incurred over the 2010 to 2011 period.

Response:

Below is a restated Table 6.1-15 (Application, Exhibit B-1), page 326, for removal/retirement costs to include a column for 2010 actuals. The forecasts for 2012 and 2013 were prepared primarily based on 2010 actual experience. The 2012 forecast is 2.5 percent higher than the 2010 actuals and the 2013 forecast is 5 percent higher than the 2010 actuals. The 2012 and 2013 forecasts include approximately $250 thousand for labour/vehicle inflation.

$000s	2010 Actual	2011 Projection	2012 Forecast	2013 Forecast
Mainland	11,909	11,290	12,609	12,932
Vancouver Island	790	344	632	648
Whistler	221	5	6	6
Fort Nelson	7	0	0	0
Total	12,927	11,639	13,247	13,586

The majority of removal/retirement costs (92 percent) are forecast for the Mainland and a detailed table is included below which summarizes these costs by category and includes columns for 2010 actuals and average spend for 2010/2011.

Removals/Retirements - Mainland ($000s)	2010 Actual	2011 Projected	2010/2011 Average	2012 Forecast	2013 Forecast
Misc. i.e. stations/facilities	377	105	241	209	232
Mains	441	500	471	700	1,000
Meters	2,216	1,000	1,608	2,700	2,700
Services - Customer Driven	5,140	6,160	5,650	5,500	5,500
Services - Company Driven	3,735	3,525	3,630	3,500	3,500
Total	11,909	11,290	11,600	12,609	12,932

Mains/Miscellaneous Removals/Retirements:

Representing 7 percent of total retirement costs in 2010, the Mains/Miscellaneous category of removal costs is relatively small and difficult to forecast. These projects are often project specific (i.e. station/facility removals) and are usually a much smaller portion of a larger system improvement type of project. Forecast levels for 2012 and 2013 are based on a steady stream of requests from third parties to move pipe in conjunction with major infrastructure projects such as roadway changes, highway interchange relocations.

Meter Removals/Retirements:

Meter removal and retirement costs were 19 percent of the total in 2010 (see description on page 327). In addition to regular meter retirement activity in 2010, in 2012 we have included an additional $500 thousand in each of 2012 and 2013 to eliminate approximately 10 thousand inactive meters.

These are meters currently attached to premises which are considered inactive – for the most part, the customers are contacted to check for potential future usage; if no, then the meter is removed; if yes, then we will reactivate the customer and include as a customer addition.

The meters removal/retirement budget in 2010/2011 was set at $1.0 million and substantially exceeded in 2010 and is likely to be to be at similar levels in 2011. The reason for the variance is that the Companies increased the number of residential meter exchanges in the 2010/2011 period to ensure meter life cycles were maximized and 1/20th of the meter fleet was exchanged annually. The costs of completing the meter exchange are divided between O&M, new meter capital installations and meter removals and retirements. The bulk of residential meters are no longer repaired after exchanged as the cost of the meters has decreased over time, the cost of the labour to refurbish has steadily increased over time and it is now more cost effective to simply retire the meter at the end of its 20 year life.

Service Removals/Retirements/Abandonments:

The majority of Mainland removaléretirement costs (75 percent in 2010) are related to Services (see the description in the Application, on page 327) which are either Customer Driven or Company Driven. Further detail on the unit cost by type of retirement is provided in the table below.

	2010 Actuals			2012 Forecast			2013 Forecast		
Service Retirement Type	Jobs	Unit Cost ($)	Total Dollars ($000s)	Jobs	Unit Cost ($)	Total Dollars ($000s)	Jobs	Unit Cost ($)	Total Dollars ($000s)
Customer Driven	3736	1376	5140	3929	1400	5500	3793	1450	5500
Company Driven	2013	1855	3735	1892	1850	3500	1750	2000	3500

For 2012, for Mainland Service Retirements (Customer Driven) we have forecast a minor increase in number of jobs (activities) from 2010 levels to reflect a slight recovery in the economy and continued in-fill development. We have also factored in a slight change in unit costs primarily due to labour/vehicle inflation. For 2013, we have forecast a similar level of expenditure due primarily to slightly lower units of activity offset by a slight increase in unit cost due primarily to labour/vehicle inflation.

For 2012, for Mainland Service Retirements (Company Driven) we have forecast a slight decrease in number of jobs (activities) from 2010 levels to reflect a minor reduction in the program. Unit costs have been forecast to remain stable compared to 2010 levels. For 2013, we have forecast the same level of overall expenditure due primarily to lower units of activity offset by an increase in unit cost due primarily to labour/vehicle inflation. Factored into the 2013 unit costs was also recognition that some of the more costly complex retirements would become a larger part of the mix of service retirements.

146.0 Reference: Negative Salvage

Exhibit B-1, Application, Section 6.1.5.4, pp.325-327; Table 6.1-15

Retirement Costs

Table 6.1-15: Approved, Actual and Forecast Retirement Expenditures

Utility/Region, ($ thousands)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 11,290	$ 12,609	$ 12,932
Vancouver Island	344	632	648
Whistler	5	6	6
Fort Nelson	-	-	-
	$ 11,639	$ 13,247	$ 13,586

The forecast expenditures for 2012-2013 for miscellaneous and mains retirements are generally project specific whereas the forecast for meters and services is generally recurring annual work that is expected to remain fairly consistent from 2010 actuals.

146.1 Since the trend in retirement costs differ between miscellaneous and mains retirements and meters and services as per the comment made above, please provide details of the proportion of retirement costs that relate to each activity for each utility. Please provide this information for Actual 2008, Actual 2009, Actual 2010, Approved 2011, Projected 2011, Forecast 2012 and Forecast 2013, by completing the following table for retirement costs:

	Actual 2008	Actual 2009	Approved 2010	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland – Meters and Services								
Mainland – Mains and Miscellaneous								
Vancouver Island – Meters and Services								
Vancouver Island – Mains and Miscellaneous								

	Actual 2008	Actual 2009	Approved 2010	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Whistler – Meters and Services								
Whistler – Mains and Miscellaneous								
Fort Nelson – Meters and Services								
Fort Nelson – Mains and Miscellaneous								

Response:

Provided below is a summary of removal costs based on FEU's capital expenditure records.

Summary of Retirement Expenditures
($ thousands)

	Actual 2008	Actual 2009	Approved 2010	Actual 2010	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Mainland - Meters and Services	6,449	6,415	7,435	11,090	10,685	12,667	11,909	11,932
Mainland - Mains and Miscellaneous	973	1,581	603	818	605	717	700	1,000
Total (actual)	7,422	7,997	8,038	11,909	11,290	13,384	12,609	12,932
Vancouver Island - Meters and Services	264	284	294	535	294	437	250	250
Vancouver Island - Mains and Miscellaneous	240	340	50	255	50	74	382	398
Total (actual)	504	624	344	790	344	511	632	648
Whistler - Meters and Services	5	6	5	11	5	5	5	5
Whistler - Mains and Miscellaneous	0	160	-	210	-	-	1	1
Total (actual)	5	166	5	221	5	5	6	6
Fort Nelson - Meters and Services	9	23	-	7	-	-	-	-
Fort Nelson - Mains and Miscellaneous	-	-	-	-	-	-	-	-
Total (actual)	9	23	-	7	-	-	-	-

146.2 For the retirement costs above, please provide explanations for variances from the prior year that are greater than +/- 5%.

Response:

The mains, service retirements and meter categories have variances greater than 5 percent and are explained below.

The retirement of mains is directly related to and proportional to the expenditure for main replacements due to integrity replacements or third-party requests. With an increase in forecasted main replacements, a proportional increase in retirements is anticipated. The replacement of mains on an ongoing basis is expected to increase as the steel pipe and coating system deteriorates and as municipalities undertake upgrades to their nearby buried infrastructure.

Service retirements can be customer driven or company driven. The total expenditures for service retirements have varied from $4.8 million in 2008 to the forecast of $5.5 million in 2012/2013. The amount fluctuates from year to year as they are primarily driven by customer requests. The number of jobs for Mainland has varied from 3,574 in 2009 to the forecast number of 3,929 in 2012. This type of activity, generally associated with older home demolitions, fluctuates from year to year with economic cycles. Another contributing variable in the fluctuations in expenditure levels are the unit costs. Unit costs, all things being equal, rise by inflation as most of the costs are for labour and materials and most of this type of work is done by in-house crews. Unit costs will also vary due to the location and complexity of the retirement.

Also, in recent years, the Companies have seen an increase in meter retirements as a result of high meter recall activities. This has led to an increase in overall meter retirement costs.

147.0 Reference: Exhibit B-1, Application, pp. 287 – 289

Negative Salvage

Commission Staff wish to explore alternatives to collecting and managing funds related to the recovery of net negative salvage costs.

147.1 Why should the funds related to the net negative salvage costs that are collected from rate payers not be maintained in a segregated account?

Response:

The following is in response to BCUC IR 1.147.1 and 1.147.2.

The Companies do not believe the use of a segregated account is appropriate or efficient to manage the funds related to the negative salvage costs. As per the NEB Decision, the use of a segregated account was in relation to pipeline assets that were much different than the FEU assets, and where there may be a legitimate issue on a going concern basis as to the ability of the pipelines to address abandonment and salvage costs. Given the diversified asset base of the FEU, this concern does not exist and therefore a segregated account is not relevant or appropriate. Based on a high level review of other natural gas distribution utilities in Canada and the US, it appears that the use of segregated accounts for negative salvage funds is not undertaken elsewhere.

Segregated accounts are also not efficient or beneficial to customers and incur costs that appear to deliver no real value to customers.

The FEU have considered the objectives of segregating funds as laid out in the NEB decision on Page 41:

"The Panel recommends that any process and mechanism for setting aside the funds for abandonment have the following attributes:

- *funds must be maintained in a segregated account and not be commingled with a company's general corporate funds;*
- *funds must be managed by an independent, third party;*
- *funds collected must be protected from creditors;*
- *funds must be protected from misuse or use for a purpose other than abandonment;*

- *regular reviews (at least every five years) of the amount of funds set aside and disbursed from the segregated account must be incorporated, and regular reporting to the Board and stakeholders must be built in;*
- *funds must be segregated by pipeline;*
- *funds must be subject to Board audit, as appropriate;*
- *companies must develop a sound investment policy for abandonment funds as ultimately, accountability for the collection and governance of the funds rests with each pipeline company; and*
- *the process for accessing the funds must be clearly set out in the mechanism."*

The following discussion focuses on specific issues associated with segregating funds through the establishment of a trust relative to certain key areas of interest that were noted by the NEB.

1. <u>Access to Funds</u>

In the NEB Decision, the Board recommended at Page 42, "in order to access the funds to cover costs of physically abandoning facilities and the costs for undertaking abandonment planning activities, companies will generally require a Board order…"

While this requirement would be reasonable where asset dispositions are outside the ordinary course of business (such as would be the case with the abandonment that results in the permanent cessation of operation such that the cessation results in the discontinuance of service as contemplated in the NEB decision), it is not a reasonable methodology for access for the routine everyday removal costs that are incurred by the FEU.

The FEU would require access to removal cost funding on an ongoing basis; a solution might be to have a quarterly process whereby the net amount of removal costs to be incurred less the removal costs collected from customers would be remitted to the trust. At current levels, these quarterly remittances to the trust would total approximately $1 million for FEI; in future years they could be smaller or may even revert to a net withdrawal. The FEU believe that the ensuing process would not be administratively efficient for the relatively small dollar values involved.

2. <u>Administrative Costs</u> (including setting up systems to track by asset class)

There are a number of administrative issues and resulting costs that arise under a trust scenario. First, the set up and ongoing maintenance of the trust arrangement incur costs, estimated to be in the order of $100 thousand to $150 thousand, which are not necessary.

Second, tracking systems would be required to segregate funds in the trust by asset class. This tracking system already exists in the FEU and such redundancy would not be efficient. Third, trustees would be required to determine the investment strategy of the fund (i.e. secure investments with low returns) and who should bear the risk/reward of account performance, among others.

3. Tax Implications

The tax issues associated with the creation of a trust are extremely complex and would require significant legal and tax expertise to resolve. Some significant issues are:

a. Will the utility be able to deduct the contributions it makes to the trust on behalf of customers? Under existing tax legislation such contributions are not deductible by the utility for income tax purposes.

b. Will the trust be able to deduct the payments it makes to the utility? The FEU understand that the pipeline companies that are the subject of the NEB process are considering requesting a tax ruling on the deductibility of payments made by the trust to the utility. Any such ruling could take several years, and would only be binding in respect of a particular taxpayer and a specific proposed transaction. It should also be noted that the facts pertaining to pipeline companies differ significantly from the facts pertaining to the FEU.

c. Who will pay the tax on the investment income in the trust? If the utility is both the settlor and the beneficiary of the trust, then the investment income earned in the trust will be deemed to be the income of the FEU for income tax purposes.

d. Could losses be trapped in the trust? If amounts that are paid out by the trust are not matched by trust income, expenses will be trapped in the trust.

Overall the tax issues are extremely complex, without precedent in Canada, and the FEU believe they would be very costly and complicated to resolve with no certainty at this point as to the outcome.

4. Customer Impact

Under the FEU's current proposal, the customer rate impact of the treatment of negative salvage is clear. The FEU include a provision for negative salvage in its cost of service, reduce the rate base by the accumulated difference between the amounts collected from customers and the actual amounts expended, and deducts the actual expenditures for tax purposes.

As an example, and ignoring working capital implications of the trust fund proposal, assume that the negative salvage (removal cost) collections in a year are $15 million, the actual expenditures are $10 million, and the tax rate is 25 percent.

a. *The FEU's proposal:*

   The revenue requirement to be recovered from customers is equal to $15 million grossed up for tax, less the tax benefit of the $10 million deducted, less the earned return on the net liability held in rate base (in this case $5 million). For FEI, the current earned return that decreases the revenue requirement for the benefit of customers is 7.75 percent.

b. *Trust fund proposal:*

   The revenue requirement treatment is not clear due to the uncertainty around the deductibility of the removal costs. Under the most favourable scenario the revenue requirement to be recovered from customers would be equal to $5 million grossed up for tax, less the investment income earned in the trust. Under the assumption of a 5 percent pre-tax return, the after tax return to customers would only be in the order of 3.75 percent instead of the 7.75 percent under the FEU's proposal.

   In this example, the trust fund proposal results in an increase in revenue requirements of approximately $200 thousand for customers due to the lower return in the first year. This difference would grow as the negative salvage deduction from rate base grows on an annual basis.

Based on the above discussion, establishing and maintaining a segregated trust fund incurs costs and increases complexity from an administrative and tax perspective. The trust account structure may be applicable when there is a justified concern that the legal entity that owns assets with abandonment and salvage obligations may not have the financial ability to meet its obligations. Given the relative size of the funds that would be subject to the fund relative to the size of the FEU entities and the diversified customer and asset base, the situation that may justify segregation of funds is not applicable. Additionally, the incremental costs to customers with no real value arising from the trust account structure supports the FEU position that the use of segregated funds is not appropriate.

<u>Conclusion</u>

For these reasons, the FEU are recommending that the provisions continue to be held by the utilities, but in separate accounts, and tracked by asset class. The provisions would be subject to the same audit procedures as any other account in the FEU's financial statements. The Companies would continue to manage and track the account and would update removal cost collection rates to reflect changes in current and future practices, and would continue to deduct actual costs incurred for tax purposes and return that benefit to customers. The Commission would have the same visibility into the account as they would into a separate fund. Customers would receive the higher less risky return on any accumulated net salvage provision as a credit to rate base and would appropriately bear the costs related to the assets that are being used in utility service.

147.2 What are the pros and cons of segregating the funds related to the recovery of net negative salvage costs?

Response:

Please see the response to BCUC IR 1.147.1.

147.3 Explain whether or not FEU should be required to seek approval from the Commission, prior to incurring expenses for the removal or deactivation of major facilities?

Response:

Please see the response to BCUC IR 1.137.9.

148.0 Reference: Analysis of Asset Retirement Losses

Exhibit B-1, Application, Appendix E-3, p.1

Asset Loss Report

FEI accumulated unrealized losses on asset retirements totalling $149M by then end of 2009.

148.1 Please provide a table indicating which years the incurred losses occurred, by dollar amount.

Response:

The table below shows the continuity of the gain/loss account that is a component of accumulated depreciation (columns 2 through 4), by year. FEI has also included a continuity of the removal costs that are included in the gain/loss account (columns 5 through 7), so that the build up of the portion of the gain/loss account applicable to unrecognized losses of approximately $92 million (column 8) is also shown by year, and the amount of the gain/loss excluding removal costs is also shown by year (column 9).

Analysis of Gain/Loss Account by Year for FEI in $ Thousands

	Total Account Balance			Removal Costs Included				
Year	Opening balance	Net losses	Closing balance	Opening balance	Removal costs	Closing balance	Net loss balance	Annual gain/loss
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2000	23,746	(6,481)	17,265	15,297	(891)	14,406	2,859	(5,590)
2001	17,265	17,388	34,653	14,406	3,146	17,552	17,101	14,242
2002	34,653	11,291	45,943	17,552	1,191	18,743	27,200	10,100
2003	45,943	11,312	57,255	18,743	4,852	23,595	33,660	6,460
2004	57,255	9,754	67,009	23,595	3,116	26,711	40,298	6,638
2005	67,009	14,391	81,401	26,711	3,300	30,011	51,390	11,091
2006	81,401	19,008	100,409	30,011	6,161	36,172	64,237	12,847
2007	100,409	7,685	108,094	36,172	6,072	42,244	65,850	1,613
2008	108,094	19,550	127,644	42,244	6,465	48,709	78,935	13,085
2009	127,644	21,309	148,952	48,709	8,363	57,072	91,880	12,946

148.2 How does the occurrence of these losses, by year, correlate to the PBR time period?

Response:

FEI was under PBR in all the years shown with the exception of 2002 and 2003. FEI does not see a correlation between the losses in the table and the PBR years.

148.3 It appears that a number of the losses resulted from less precise accounting. Can FEI explain why this occurred and how it was not detected earlier?

Response:

As noted in the FEU's responses to BCUC IRs 1.151.4 and 1.151.5 (Meter Installations / Regulators), there were some challenges in accounting for this particular asset class given the disparity in costs. The other asset classes noted in the Asset Loss report, Mains, Meters and Services did not have the same accounting challenge.

This issue was not detected earlier, as at that time, the reported "losses" appeared appropriate given the noted retirement activity for that period. It was only when the "losses" continued over a longer period that the need for further investigation was apparent.

As noted in other information request responses such as BCUC IRs 1.148.4 and 1.151.10, even though the amounts that have been characterized as losses may have been overstated for this asset category, total rate base remained unchanged as these amounts were merely reclassified to the accumulated depreciation account from the gross plant balance.

148.4 Does the Shareholder share any responsibility for these losses due to the significant time lag between incurring these losses, understanding their nature, identifying changing market trends and the impact that internal accounting had on their creation?

Response:

No. For the reasons set out below, these "losses" are appropriately included in rate base for future recovery from customers through rates. There are six key reasons why this should be the case.

First, these "losses" are the result of inadequate recovery of depreciation from customers for assets that have been removed from service due to customer request or for operational and/or safety reasons. Thus they are more appropriately characterized as unrecovered depreciation rather than "losses". As the amount is a result of under recovery of capital that was expended for the provision of service to customers, the total depreciation, included the under recovered amount characterized as losses, is appropriately recovered from customers.

Second, the FEU have followed the BCUC's system of accounting and all deprecation rates have been approved by the Commission. The Commission-approved accounting policies classify these items as "losses," but this classification does not change the amount of the rate base inclusion for these items. These items are still recovered in rates under internal accounting processes; only the timing of recovery is affected.

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.

Fourth, even if depreciation rates were forecast 100% accurately, the group system of accounting, which the FEU have followed in accordance with the BCUC's system of accounts, would result in a build up of unrecovered depreciation. The asset classes involved have an average life of approximately 40-50 years and have not yet reached their average life expectancy. 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. The individual assets that are removed from service during the years prior to the average life of the asset class will result in the recording of under-recovered depreciation. Since depreciation rates are designed to recover existing "loss" balances over the remaining service lives of the assets that remain in the asset class, as the system ages, the trend will move towards individual assets being removed from service having over-recovered depreciation. Therefore, we should expect to record under-recovered depreciation in the years prior to the average service life of the asset group.

Ultimately, the group system of accounting is designed to recover the depreciation of the asset group over the useful life of the entire asset group.

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.

Sixth, decisions and agreements not to increase depreciation rates were made based on the understanding that all unrecovered deprecation would be recovered from customers and that only the timing of the recovery would be affected. To hold the shareholder responsible for unrecovered depreciation now would constitute a significant change to the treatment of unrecovered depreciation and the current group system of accounting. Given the uncertainties inherent in forecasting the service lives of such a large quantity and variety of assets and the retirement costs of assets in the future, it is appropriate to have a provision to capture these costs as currently contemplated by the BCUC's Uniform System of Accounts. This relieves both the shareholder and ratepayers from the effect of the potential for large variances from forecast.

In summary, these "losses" are appropriately included in rate base for future recovery from customers through rates. There is no basis for the losses to be determined unrecoverable as the ratepayers are responsible to pay for service received in the form of return of depreciation to investors over time for the capital employed as plant and equipment.

148.5 Do the Companies lack an in-house expert to identify and recommend depreciation rates for all asset classes and to oversee and implement the recommendations made by external consultants?

Response:

While the FEU do not employ an in-house depreciation expert, they do have managers who have the knowledge about the assets and their expected lives and are aware of changes in the business environment that may affect the assets' estimated lives and depreciation rates.

As indicated in the response to BCUC IR 1.136.2, the FEU highlight that the development of depreciation rates for their assets follows what is common industry practice for utilities, where utility staff works with an external depreciation specialist to determine its 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.

Over the years, the FEU have consistently followed the practice of engaging an external depreciation specialist to updating its depreciation rates, with the current depreciation rates in place those that were approved by the Commission as part of the FEU's 2010/2011 Revenue Requirements applications.

148.6 Please provide an organizational diagram of the asset management department and indicate which individual is ultimately responsible for determining the asset amortization rates and negative salvage rates within the Companies? A listing of that individual's qualifications should also be included.

Response:

The Asset Accounting department (which is separate from the operationally-focused Asset Management department discussed on pages 161 to 162 of the Application, Exhibit B-1)) currently consists of four people: an Asset Accounting Manager and three Asset Accounting Analysts. Oversight of the Asset Accounting department and the final determination of amortization rates and negative salvage values within the Companies belongs to the Director of Finance and Planning. The incumbent's qualifications include approximately 20 years working experience at FEI in different positions including Marketing, Gas Supply and Finance. In addition, the individual is a qualified CGA (1994) and has an MBA designation.

149.0 Reference: Losses by Asset Category

Exhibit B-1, Application, Appendix E-3, Part 1.3, p.1

Asset Loss Report

"The $138 million figure includes $54.1 million of removal costs less salvage proceeds."

149.1 Please provide copies of the internal control policies that existed to ensure that removal costs as recorded only included costs that were specific to taking assets out of service.

Response:

Please refer to the response to BCUC IR 1.137.6 which explains the procedure for separating costs for retiring an asset versus costs for installing a new asset. In addition, accounting direction is provided in the FEU's Plant Accounting policy included in the response to BCUC IR 1.99.1.

150.0 Reference: Asset Loss Report

Exhibit B-1, Application, Appendix E-3, Part 1.3.1, pp. 2-3

Order C-8-98

Asset Loss – Regulators and Meter Installations

"The following graph shows the losses recorded in this asset category for the years 2001 to 2009. Prior to the year 2001, the gains/losses observed for this asset category were minimal.

...Starting in 2001, FEI implemented a process to retire the install labour costs included in this asset category, using the number of meters scrapped and the applicable historical unit costs based on a composite average of the activities being recorded in this account."

"B. On October 21, 1997, pursuant to Part 45 of the Utilities Commission Act (the Act), BC Gas applied to the Commission for a CPCN for approval of its Integrated Business Information System (IBIS) Project. The IBIS Project is intended to design and implement new computer hardware and software for the Finance, Materials Management, and Human Resources functions of the utility and is expected to cost approximately $21.7 million. The new system is designed to replace aging, inflexible technology and to provide reduced transaction processing and more customer oriented processes; and" (Order C-8-98)

150.1 When was the IBIS project implemented?

Response:

The IBIS project was implemented in 1999.

150.2 Was the 2001 change in the process to retire the install labour costs due to the implementation of the IBIS Project approved by Commission Order C-8-98? Please explain why, or why not.

Response:

No it was not.

The 2001 change in the process to retire install and regulator costs resulted from the recognition that no process existed prior to then to retire the majority of these assets, with the exception of large industrial meter sets which would have unique facility identification numbers assigned to them.

151.0 Reference: Regulators and Meters Installations

Exhibit B-1, Application, Appendix E-3, Part 1.3.1, pp.2-3

Asset Loss Report

"The following graph shows the losses recorded in this asset category for the years 2001 to 2009. Prior to the year 2001, the gains/losses observed for this asset category were minimal."

151.1 Why is it that the gains/losses observed for the asset category were minimal before 2001?

Response:

Please refer to the response to BCUC IR 1.150.2.

151.2 Were any of the gains/losses related to the IBIS changeover?

Response:

Please refer to the response to BCUC IR 1.150.2.

151.3 Other than the policy related to install labour costs, did the accounting policies related to the classification of asset-related costs or treatments change from 2000-2002?

Response:

The FEU are not aware of any accounting policies changes related to the classification of asset related costs or treatment changes from 2000-2002.

"Starting in 2001, FEI implemented a process to retire the install labour costs included in this asset category, using the number of meters scrapped and the applicable historical unit costs based on a composite average of the activities being recorded in this account. However, there is a wide disparity in the actual cost for the different types of meter install activities, with a simple residential install costing approximately $60 per install compared to a larger diaphragm meter install for a commercial customer at double or more. For this reason, applying a composite unit cost to determine gains/losses for retirements, particularly a lower cost residential install, has resulted in an overstatement of losses.

Analysis of the losses reported for the recent years 2006 to 2009 show that of the approximately 120,000 meters scrapped during this period, over 90% were for smaller diaphragm meters used for residential customers. Yet, the loss reported on a per meter installed basis ranged from $100 to $150 each, significantly higher than the $60 per meter install stated earlier.

On a retrospective basis, if a revised historic unit cost ranging from $60 to $100 meter install was used for the period 2006 to 2009, the retirement loss recorded for that period would instead range only from $4 to $7 million compared to the actual reported loss of approximately $15 million. Total rate base would remain unchanged as the losses would be reclassified to accumulated depreciation from the asset loss balance."

151.4 At the time that it was determined to use the composite unit cost average for estimating install labour costs, was it known that actual costs varied by meter type. For example larger commercial meters had different costs than smaller residential meters?

Response:

Yes, as indicated in the Asset Loss report, it was recognized that costs in this asset category vary. However, at that time, the FEU felt that they had developed a reasonable composite estimate of a historic unit cost for retirement purposes. The FEU believed using an average composite unit cost appeared to be a more reasonable approach for retirement activities than recording asset retirements using different individual unit costs. As noted in other information request responses such as BCUC IR 1.148.4 and 1.151.10, even though the amounts that have been characterized as losses may have been overstated for this asset category, total rate base remained unchanged as these amounts were merely reclassified to the accumulated depreciation account from the gross plant balance.

151.5 Why did FEI not test the accuracy of this cost estimate after putting the new policy in place in 2001?

Response:

At that time, the reported "losses" appeared appropriate given the noted retirement activity for that period. It was only that the "losses" continued over a longer period that highlighted the need for further investigation.

Even though the amounts of unrecovered depreciation that are characterized as losses may have been overstated for this asset category, total rate base remained unchanged as the losses were reclassified to the accumulated depreciation account from the gross plant account. In addition, as noted in the response to BCUC IR 1.136.2, the unrecovered depreciation is primarily due to the difference between the actual life of an asset and the estimated life. Any difference arising would impact only the timing of when the historic cost of an asset is recovered from customers.

151.6 Does FEI not have a policy in place that all accounting estimates, particularly ones that could have a material impact on the financial statements, should be tested for accuracy against historical results on a regular basis?

Response:

The FEU test their accounting estimates for accuracy against historical results on a regular basis. For the Meter Installation and Regulator asset class, testing did occur, but did not detect the issue until recently. In the future, the FEU plan to review their depreciation and negative salvage estimates regularly (i.e. every 3 to 5 years) in order to adjust the rates as required for reasonableness. In addition, the FEU plan to report annually actual results against forecasts to test for reasonableness.

The FEU note that even with the overstatement of the under-recovered depreciation, the total rate base (net book value) was unaffected and did not materially impact the financial statements of the Companies (i.e. balance sheet).

151.7 Given FEI's plan to estimate salvage value costs in the future, does this historical track record of not testing and then correcting accounting estimates demonstrate a cause for concern? What other steps has FEI taken to avoid similar situations in the future whereby an estimate or average value is used to estimate a cost and that estimate/average value is not reflective of true cost?

Response:

One instance of one asset class where estimates, in hindsight, were not accurate does not establish a "historical track record of not testing and then correcting accounting estimates". As stated in other responses, there are many estimates included in the determination of both accounting income and rates. It is expected that there will be variations between estimated amounts and actual experience, but that on balance the estimates will be reasonable and over time will be adjusted for experience. Regardless of the accuracy of the estimate, the end result is that the cost of the asset will be recovered from customers over time.

As indicated in the response to BCUC IR 1.143.5, the FEU support annual reporting of actual results against provisions. In addition, consistent with industry practice, the FEU recommend that reviews of depreciation and negative salvage estimates be performed regularly (i.e. every 3 to 5 years) in order to adjust the rates as required to ensure their reasonableness.

151.8 Are there any other averages or composite values used to estimate installation cost or retirement costs within this or any other asset in use within the Companies. If so, what work has been done to verify the accuracy and appropriateness of the use of these averages?

Response:

No other composite values similar to that used for the meter installations / regulators are being used for asset accounting retirements where an estimate of the dollar cost to install is used as the basis for retirement.

Different from meter installation / regulators, retirement of distribution mains and services use average retirement values based on historical costs incurred divided by the number of activities for that year (i.e. metres of service lines). These are accurate and appropriate for retirement purposes as the costs and activities included are fairly homogenous.

151.9 Please confirm that the FEI PBR period was from 2004-2009?

Response:

FEI confirms that the most recent PBR period was from 2008 to 2009 extending the original PBR which ran from 2004 through 2007 with minor modifications.

151.10 If the costs were reclassified as depreciation, please confirm that the reclassified amount of accumulated depreciation account would require an equal and offsetting entry to depreciation expense for an amount between $8M-$11M ($15M less $4M to $7M)?

Response:

This response addresses BCUC IRs 1.151.10 through 1.151.13.

To correct the overstatement of any unrecovered depreciation (characterized as losses), an entry would be required to the gross plant balance for the asset class (DR asset; CR accumulated depreciation), not to depreciation expense as stated in the question. This entry would have resulted in some impact on depreciation expense as the asset base on which depreciation is calculated would have been higher. The impact on depreciation expense is difficult to estimate, since the amount of the "losses" of $4 to $7 million was an indication only of the potential size of the error. However, under the assumption that the losses were reduced by 60 percent over the 2006 to 2009 period with a corresponding increase to the gross asset cost, FEI calculates that this would result in an increase in depreciation expense of approximately $800 thousand over that period. This increase would have been offset somewhat by the fact that a lower depreciation rate would have been selected as the recommended rate during that period since the balance in accumulated losses would have been less. FEI estimates this would have reduced the depreciation expense from $800 thousand to less than $700 thousand, of which half would have been shared with customers during the PBR period.

During the most recent PBR period (from 2004 to 2009), FEI and customers shared in ROE variances from approved. The total amount shared with customers over the PBR period was $68.7 million pre-tax. Had the adjustments been made, the approximately $700 thousand net variance above would have increased the actual cost of service and decreased the earning sharing calculation which would have increased the effective delivery rates during that time through a reduction to the earnings sharing rate rider. Therefore customers benefited in the form of lower rates over the period in question.

The shareholder should not be required to repay any earnings sharing difference that would result if the variance amounts had been expensed during the PBR period. In the PBR term, there were a number of estimates included in the determination of the earnings sharing and in the determination of accounting. Although it is not expected that individual estimates will be 100 percent accurate, the FEU strive to make accurate estimates in all cases. While in hindsight the estimate of the historic unit costs of regulators and meters was less accurate than desired, the estimates appeared reasonable at the time. Ultimately, the estimates were incorporated into the PBR agreement which was approved by the Commission. The FEU do not believe it is in the interest of any party to revisit previous year's estimates and revise based on hindsight. This would bring significant uncertainty to both ratepayers and the shareholder. Moreover, to revisit the estimates embedded in the PBR period at this time and require the shareholder to return earnings based on revised depreciation would be retroactive ratemaking.

151.11 During the PBR, did the shareholder of FEI receive any performance based compensation resulting from the PBR? Please explain.

Response:

Please see the response to BCUC IR 1.151.10.

151.12 If some of these amounts had been recorded as accumulated depreciation during 2004-2009, would this have resulted in higher cost of service to record the depreciation expense and a reduction in performance based compensation for the shareholder?

Response:

Please see the response to BCUC IR 1.151.10.

151.13 If some of these costs represent amounts that otherwise would have been expensed under a PBR, should the shareholder be responsible to repay any incentive compensation that would not have occurred if the accounting for the losses had been more precise?

Response:

Please see the response to BCUC IR 1.151.10.

"The above analysis highlights the challenges with developing a retirement process for a wide and disparate asset category such as the Meter Install. To address this, Gannett Fleming recommends adopting an approach that records new plant additions for this asset class in a separate account, with depreciation calculated using a whole life rate."

151.14 Given the challenges of developing a retirement process for certain asset classes, why does FEU believe that they are able to accurately estimate asset retirement costs (negative salvage amounts) given the challenges that exist to estimate installation costs which have already been incurred?

Response:

The FEU believe the approach as recommended by Gannett Fleming and outlined in the response to BCUC IR 1.136.1 provides reasonable estimates for the Companies' negative salvage rates. The approach recognizes that the recommended negative salvage rates need to be reviewed regularly and adjustments made to the rates to reflect refinements in the assumptions.

The FEU believe that simply because it may be challenging to estimate retirement costs, does not mean that it should not be undertaken. The alternative is to saddle future generations with the costs of current customers' service delivery.

151.15 Aside from setting up a new asset class in an attempt to simplify the process, what additional procedures does FEU intend to implement to ensure adequate rigour exists in the process of estimating retirement costs? Has FEI modified policies to test the accuracy of all accounting estimates on regular basis to avoid a similar situation in the future?

Response:

The FEU clarify that the challenge for the asset class meter installations / regulators was not in estimating the costs of retirement and instead was due to the difficulty in estimating the historic costs to use in retiring assets in the asset category, which resulted in an overstatement of under-recovered depreciation in this asset class.

The FEU believe the proposed change in treatment to record the negative salvage provision separately instead of the accumulated depreciation account will create more transparency and enhance the process for testing of estimates used for asset accounting. The FEU will be undertaking to review for reasonableness any entries recorded in the provision account on a quarterly basis. This process is similar to that used by the FEU for deferral accounts.

151.16 Given that the first step of creating new asset classes, tracking costs, is not yet in place, how can FEU be certain that proposed changes will be effective in providing sufficient understanding of the costs of assets in-use in order to make the appropriate estimates?

Response:

The FEU assume the question is referring to the broader concern of ensuring asset losses recorded are representative and that estimates used are regularly tested for validity.

As outlined in the response to BCUC IR 1.151.15, the FEU believe the greater visibility in removal costs and also in asset losses as the result of using a deferral account that was introduced starting in 2010 will enhance the process for regularly testing the losses and the reasonableness of any estimates used. In addition, as indicated in the response to BCUC IR 1.151.6, the FEU plan to also report on an annual basis a comparison of estimates versus actuals to ensure reasonableness.

151.17 Should the Companies have a proven track record of operating an effective asset cost estimation and allocation process before requesting Commission approval to proceed in making even larger estimates of future asset retirement costs that are recovered from ratepayers before such costs are even incurred (i.e. negative salvage costs)?

Response:

As stated in the response to BCUC IR 1.136.2, the FEU's asset accounting system and processes follow a group accounting approach that is reasonable and sufficient to adequately account for the Companies' assets, including adequately estimating the depreciation of its assets. While there was a challenge with the meter installation / regulator asset category due to the specific circumstances, the FEU believe their other asset classes have been accounted for properly. It is this experience that FEU will build on and extend to accounting for negative salvage.

As indicated in the response to BCUC IR 1.143.1, it is not reasonable to expect that estimates for negative salvage rates will be 100 percent accurate. However, the FEU believe that a reasonable estimating process based on historical results is more desirable than the alternative of not collecting removal costs until the assets are removed from service at all. Delaying the collection of removal costs until after the assets are removed from service means that the customers receiving service never contribute to the ultimate costs of removal, resulting in intergenerational in-equity.

152.0 Reference: Meters

Exhibit B-1, Application, Appendix E-3, Part 1.3.2, p.6

Asset Loss Report

"Based on the company's meter retirement data, FEI has observed that the average residential meter life has been less than the 25 – 28 years as previously anticipated. The shorter residential meter life is linked to the increased cost to refurbish residential meters relative to the cost to replace these same meters. In the past, FEI's operating model had residential meters being removed from the field after approximately 14 years in service for refurbishment. The meters were then re-installed with the expectation that these meters would again be removed from the field within another 14 years, for a service life totalling 28 years."

152.1 At what point did FEU realize that its meters were being retired earlier than anticipated?

Response:

The FEU refer the Commission to Section B Tab 1 page 188 of FEI's (then Terasen Gas Inc.) 2010-2011 RRA, Exhibit B-1, where FEI discussed the shortening of the meter life. The relevant text from page 188 is provided here for ease of reference.

"Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006 - 2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy which provided both customers and shareholders the cost benefits of previous investment in the fleet.

The adoption of a residential meter exchange frequency based on a 20 year life expectancy creates good alignment for the inevitable adoption of Automatic Meter Reading ("AMR"). AMR technology involves equipping a gas meter with a radio transmitter to broadcast meter readings to a collection device. AMR transmitters have a battery life of approximately 20 years so it is advantageous to harmonize meter recall frequency to this life expectancy."

In addition, there were a number of information requests related to this issue in the 2010-2011 RRA filing including BCUC IR 1.134.1 (Exhibit B-4-1) and CEC IR 1.44.1 (Exhibit B-6) (see excerpts below) which support the discussion above.

Excerpt 2010-2011 RRA, Exhibit B-4-1, BCUC IR 1.134.1:

134.0 Reference: Metering – Meter Life Extension

Part III, Section B, Tab 1, p. 188

"This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006-2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy … " Ref: Part III, Sec B, Tab 1, p. 188, par. 2

134.1 Please detail the additional O&M required in 2010 and 2011 for the meter recalls deferred from 2006-2008.

Response:

One of the activities conducted within Terasen Gas to ensure the cost effective and reliable operation of the meter fleet is to adjust the meter recall schedule based on the meter fleet age distribution and the results of the performance sampling program. Between 2006 and 2008, the decision to operate residential meters to the full life expectancy of 20 years, coupled with the positive results from sampled meter performance tests, allowed the company to temporarily reduce the total number of scheduled meter recalls. Therefore, no meter recalls were deferred during the time frame referenced within the question. All meter recalls were scheduled at times that were optimal in terms of operational reliability. Finally, by temporarily reducing the number of meter recalls during this period, both customers and shareholders were allowed to benefit from the savings in O&M and capital expenditure.

Excerpt 2010-2011 RRA, Exhibit B-6, CEC IR 1.44.1:

44. Reference: Exhibit B-1, Page 188, Part III Section B Tab 1 – Operational Performance

Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006 - 2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy which provided both customers and shareholders the cost benefits of previous investment in the fleet.

44.1. Did Terasen prepare a business case to demonstrate the cost effectiveness of this approach to shortening the life of the meter fleet in service and if so please provide the study?

Response:

TGI has assessed the cost-effectiveness of the approach, but it is not formally documented in a study. The analysis undertaken, which demonstrates that the approach is the preferable one, is summarized below.

Terasen Gas' strategy related to the refurbishment of meters has been largely influenced by the relative difference between the labour expense associated with meter refurbishment and the purchase price of new meters. In the case of commercial and industrial meters which incur a relatively high replacement cost, the decision to refurbish the meters has proven to be the more cost effective option. As such, Terasen Gas currently engages in the practice of recalling these meters for refurbishment and re-deployment into the field. Alternatively, residential meters are manufactured in relatively large quantities allowing vendors to benefit from the resulting economies of scale. As a result, the unit price for residential meters has remained relatively low in relation to labour costs associated with meter refurbishment. Therefore, the decision to operate the residential meters to the end of their useful lives prior to replacement is currently the most cost effective approach to meter management.

The expenses involved in this analysis are monitored by Terasen Gas as part of normal operation and therefore the analysis has not been documented within a formal study.

Also, Gannett Fleming noted possible changes in meter life in the previous 2007 depreciation study. On page II-25, Gannett Fleming stated:

The retirement rate analysis for this account, as presented at page IV-61, indicates retirement activity throughout the accounts life constant with an Iowa 25-R2 shape. While this account is experiencing significant change in both the capitalization policies and in the technology associated with the assets within this account, the impacts of these changes are not known at this time. Therefore, absent any empirical data to support a shortening of the average service life estimate, the 25-R2 has been selected for this account. This account will be closely monitored over the next few years to determine if a shortening of the average service life estimate becomes necessary.

152.2 Why was this item not detected in the last depreciation study (less than 3 years ago)? Is this the reason for over $18M of unrecorded losses as at the end of 2009?

Response:

Please refer to response to BCUC IR 1.152.1.

The reason for the approximate $18 million of unrecovered depreciation (losses) for the Meter asset category was not due to failure to detect the trend in meter retirements. The $18 million of losses reported has accumulated over time, with the majority of the losses from 2001 to 2009, and resulted from meter lives being shorter than what had been provided for in depreciation rates. This trend of unrecovered depreciation being recognized would be expected to reverse over time with the implementation of updated depreciation rates.

Please refer to Figure E3-2: Losses for Asset Class 478 by Year from the Application, (Exhibit B-1) Appendix E3, showing the losses recorded by year.

152.3 How was FEI able to go for so long without detecting that the depreciation of this asset class was not sufficient to recover its value during its useful life? Also in your response, please address this matter as it relates to assets class 474 as well.

Response:

Please refer to response to BCUC IR 1.152.1.

Recognizing that meters and related meter installations were experiencing shorter lives, FEI has in the past revenue requirement applications recommended and received approval for higher depreciation rates for both asset classes.

FEI refers the Commission to page 38 of the Commission's decision on BC Gas Utility's 2003 Revenue Requirement Application dated February 4, 2003 (Order G-7-03).

Excerpt from Order G-7-03, page 38:

> "7.1 Depreciation (2004)
>
> *BC Gas applied for an increase in depreciation rates in 2004 for both its PC software and its customer meters and regulators, based upon a depreciation study done in 1996. The software would be depreciated over five years at 20 percent per year, rather than eight years at 12.5 percent per year. Meters would be depreciated over two 14-year cycles resulting in an increase in depreciation from 3 percent per year to 3.57 percent per year (T4:821). BC Gas states that these are the useful lives of these assets as experienced by the Utility and should therefore be reflected in the depreciation rates (T7:1425)."*

The approved depreciation rate for meters has been increasing over the last decade reflective of the shorter life of the meter. Prior to 2004, the rate approved was 3 percent, which increased to 3.57 percent starting in 2004 and then to the current approved rate of 5.31 percent in 2010. The proposed rate starting for 2012 is 7.89 percent. The asset class 474 Meter Installation / Regulators depreciation rate has experienced the same rising depreciation rate as in the meter asset class.

153.0 Reference: Asset Loss Report

Exhibit B-1, Application, Appendix E-3, Part 1.3.3, p. 8

FEI General Terms and Conditions (GT&C), Part 10.13, p. 10-3; FEVI GT&C, Part 10.13, p. A-14

Asset Loss – Service Lines

"10.13 ***No Unauthorized Changes*** *- No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other Persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line*

(a) must be approved in writing by FortisBC Energy, and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer." (FEI GT&C, p. 10-3; and FEVI GT&C, p. A-14)

"Table E3-2: Most Services Retired Due to Customer Requests

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs
Customer	76,958	$4,079,701	76,893	$4,235,239	68,959	$4,913,276	72,817	$4,906,138
Safety	11,303	$584,850	30,733	$311,291	45,852	$471,291	10,811	$499,975
Total	88,261	$4,664,551	107,626	$4,546,530	114,811	$5,384,566	83,628	$5,406,113

The data above indicates that the majority of retirements expressed in metres of pipe retired and the retirement costs incurred were the result of customer initiated requests.

…To mitigate the rate impact to all customers, FEI seeks to recover the retirement costs from the customer that initiates the work wherever possible." (Exhibit B-1, Appendix E-3, p. 8)

153.1 Given that the FEU GT&Cs require that "changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer", please explain why approximately $18.0 million of service line retirement costs were not collected from customers from 2006-2009.

Response:

For clarity, the FEU lists the specific wording contained in Section 10.13 of the Companies' respective GT&Cs.

> *"10.13 **No Unauthorized Changes** - No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other Persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line (*emphasis added*)*
> *(a) must be approved in writing by FortisBC Energy, and*
> *(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer."*

The FEU confirm that Section 10 of the FEU's GT&Cs applies to establishment or continuation of a Service Line, which may include choosing a route, site preparation, construction, connections, additions, and maintenance. As the wording of Section 10.13 indicates, subsections (a) and (b) specifically apply to "any change in the location of an existing service line," and does not apply to retirement or abandonment of a pipeline that is removed from service. In accordance with the GT&Cs, FEU charges a customer who wants to relocate or alter a Service Line which will be continuing in-service.

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.

153.1.1 If the Companies have not complied with the FEU GT&C's requirement to collected service line retirement costs due to customer requests, should the shareholder be responsible for these costs? Please explain.

Response:

As discussed in response to BCUC IR 1.153.1, the FEU believe they are in compliance with their GT&Cs.

Section 10 of the FEU's respective GT&Cs applies to establishment or continuation of a Service Line, which may include choosing a route, site preparation, construction, connections, additions, and maintenance. As the wording of Section 10.13 indicates, subsections (a) and (b) of section 10.13 specifically apply to "any <u>change in the location</u> of an <u>existing</u> service line," and does not apply to retirement or abandonment of a pipeline that is removed from service.

The FEU believe there is no basis for the shareholder to be responsible for these costs.

153.2 Please provide the latest copies the FEU policy and procedure manuals used by the individuals (operations and fixed asset accounting) responsible for the retirement of service lines.

Response:

Please refer to BCUC IR 1.99.1, Attachment 99.1 which provides the FEI Plant Accounting policy manual. Section 4 of the manual titled Plant in Service and Retirements provides guidance for the retirement of service lines. In addition, following is the procedure used for service retirements by Asset Accounting.

- The total quantity of all service retirements is obtained from the SAP system which records the required information captured by Operations.
- Unit costs for the retirement of service assets are calculated based on the historical records of services by their year of installation.
- The retirement amount for each service asset is calculated by applying the appropriate unit cost for that asset by the metres of pipe retired.
- The retirement is recorded in SAP for each asset with any under or over-recovered depreciation (gain/loss) on retirement posted to the gain/loss deferral account.
- Retirement Unit Cost tables are computed annually for Recurring Plant, and used to establish retirement values based on quantity supplied by Operations.

Attachment 153.2 contains, for the Operations group, the Standard CUS 07-05 Charges for Service Line Work and provides guidance for handling of Abandonment/Supply Cut-off requests (page 13).

153.3 Using the format of the table below provide the five highest cost service line retirements each year for 2006-2009. Provide the table in fully functional electronic format.

2006
Five Highest Cost Service Line Retirements

	Work Order Number	Name	Location	Metres of Services Retired	Remaining Net Book Value (NBV)	Retirement Costs	Retirement Cost and Remaining NBV Recovered from Customers
1							
2							
3							
4							
5							

Response:

Provided below are the five highest cost service line retirements for each of the years from 2006 – 2009. Attachment 153.3 contains the fully functional excel format. The average calculated retirement cost for 2006 – 2009 period for all services is approximately $1,109 per service abandonment. Higher costs for these services are generally reflective of the increased complexity of the specific jobs. Higher costs are incurred when services are buried in the pavement or where stub services are difficult to locate. As a result, these complex removals require the use of specialized equipment. Also, additional costs and overtime may be incurred if a job is located on a busy road where municipalities require that the work be performed during the evening or on the weekend to minimize disruption to the traffic. Higher costs also arise in situations where traffic control or permitting is required and where industrial/commercial services are involved.

FEU

2006 Five Highest Cost SERVICE Line Retirements

	Work Order Number	Name	Location	Metres of Services Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30103700	Abandonment - 2 King Edward St.	Coquitlam	4.9	376	9,567	9,943
2	30111896	Abandonment - 678 Lasage Rd	Kamloops	75.2	7	8,746	8,753
3	30127849	Abandonment - 3164 160 St.	Surrey	64.0	4,102	8,460	12,562
4	30124371	1450 Government St - stub aband. @main	VICTORIA	4.9	48	8,357	8,405
5	30151122	Abandonment - 511 27 Avenue	Creston	70.8	613	7,943	8,556

2007 Five Highest Cost SERVICE Line Retirements

	Work Order Number	Name	Location	Metres of Services Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30170899	Abandonment - 9568 192 St.	Surrey	14.0	113	8,771	8,884
2	30167539	Abandonment - 5788 Vedder Rd.	Chilliwack	58.5	483	8,567	9,050
3	30190700	Abandonment - 5921 152 St.	Surrey	33.5	270	8,460	8,730
4	30173282	Abandonment AT MAIN 4 SURE	Vancouver	39.6	469	7,529	7,998
5	30190697	Abandonment - 5953 152 St.	Surrey	16.0	129	6,955	7,084

2008 Five Highest Cost SERVICE Line Retirements

	Work Order Number	Name	Location	Metres of Services Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30222421	Abandonment - 200 14666 64 Ave.	Surrey	120.0	5,334	13,744	19,078
2	30201087	5500 Alaska Hwy - Ft .Nel. Rec Ctr. Aban	Fort Nelson	67.2	788	12,167	12,955
3	30199697	Abandonment - 5650 Lougheed Hwy	Burnaby	26.0	211	11,935	12,146
4	30230215	Abandonment - 501 Boyd St.	New Westminster	20.0	2,269	10,579	12,848
5	30198523	Abandonment - 202 152 St.	White Rock	29.4	1,036	10,252	11,289

2009 Five Highest Cost SERVICE Line Retirements

	Work Order Number	Name	Location	Metres of Services Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30244281	1258 BROADWAY S	Williams Lake	62.0	2,429	18,707	21,136
2	30220003	Abandonment - 30971 Peardonville Rd.	Abbotsford/Matsqui	106.9	7,211	13,522	20,734
3	30196202	WEYERHAEUSER OFFICE IP_DP; remove	Kamloops	19.6	155	12,358	12,512
4	30265937	Abandonment - 20790 72 Ave.	Langley City	33.5	257	10,405	10,662
5	30234102	Abandonment - 825 Foul Bay Rd	VICTORIA	40.0	1,321	9,538	10,859

154.0 Reference: Asset Loss Report

Exhibit B-1, Application, Appendix E-3, Part 1.3.4, p. 9

Asset Loss – Mains

Table E3-3: Most Mains Retired for Safety and Reliability Reasons

Reasons for Retirement	2006 Metres of Main Retired	2006 Retirement Costs	2007 Metres of Main Retired	2007 Retirement Costs	2008 Metres of Main Retired	2008 Retirement Costs	2009 Metres of Main Retired	2009 Retirement Costs
Customer	1,048	$22,981	0	$6,083	0	$0	15	$535
Safety/Reliability	26,169	$513,060	54,548	525,600	53,832	474,834	21,107	591,413
Total	27,217	$536,041	54,548	531,683	53,832	474,834	21,122	591,948

"The data above indicates that the majority of retirements, expressed in metres of pipe retired and correlated to the retirement costs are primarily the result of safety/reliability related reasons."

154.1 Using the format of the table below provide the five highest main retirements each year for 2006-2009. Provide the table in fully functional electronic format.

2006
Five Highest Cost Main Retirements

	Work Order Number	Name	Location	Metres of Main Retired	Remaining Net Book Value (NBV)	Retirement Costs	Retirement Cost and Remaining NBV Recovered from Customers
1							
2							
3							
4							
5							

Response:

The calculated average cost per main retirement for all mains for the 2006-2009 period is approximately $3,929 per main. Provided below are the five highest cost main retirements for each of the years from 2006 – 2009. Attachment 154.1 contains the fully functioning excel format. The costs incurred to perform these retirements are higher than the 2006-2009 average as these are more complex removals that require extensive efforts to complete, or involve removals at multiple locations. Some retirements involve the complete removal of main buried within the pavement and require the use of specialized equipment. In some locations, extra time is needed to perform a removal due to unfavourable working conditions such as excessive depth of cover, other construction activities occurring nearby, or significant vehicle traffic. In many instances, additional requirements such as traffic control, sectionalisation, or permitting are needed.

FEU (Distribution Mains Only)

2006 Five Highest Cost MAIN Retirements

	Work Order Number	Name	Location	Metres of Main Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30046484	Keith Road off Ramp No. 1 Hwy- ABAN	North Vancouver City	47.3	1,181.19	25,795.41	26,976.60
2	30127435	Main Abandon - Timberland & Tannery, SUR	Surrey	240.0	4,946.1	25,666.23	30,612.28
3	30123226	Nelson Rd. IP aband costs	Richmond	251.0	5,948.1	23,671.90	29,619.98
4	30104184	W. 33rd.; Crown to Collingwood-Aban main	Vancouver	1,008.9	32,968.2	16,435.75	49,403.93
5	30112009	W 41st.; Trafalgar to Highbury-aban main	Vancouver	1,800.0	58,819.22	15,223.22	74,042.44

2007 Five Highest Cost MAIN Retirements

	Work Order Number	Name	Location	Metres of Main Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30162700	IP Main Temp. Abandonment	CROFTON	50.4	120.83	58,483.24	58,604.07
2	30146470	88DP/PE Abd- 107thSt-Norwell- Nanaimo SI	NANAIMO	803.0	13,753.02	35,648.61	49,401.63
3	30069069	W 49th -114 DP- Abandonment	Vancouver	699.5	22,138.27	24,190.99	46,329.26
4	30158291	Tolmie St & Belmont Ave VAN LP 114 aband	Vancouver	2,742.0	86,780.75	18,081.90	104,862.65
5	30150165	No. 10 Hwy & 146 St, Sur - Main Abandon	Surrey	325.0	6,668.69	16,746.74	23,415.43

2008 Five Highest Cost MAIN Retirements

	Work Order Number	Name	Location	Metres of Main Retired	Remaining NBV	Retirement Costs	Retirement Cost & Remaining NBV
1	30193402	Houghtaling Rd @ Hart Hwy PG-remove pipe	Prince George	150.0	54.86	46,463.34	46,518.20
2	30175279	W 49&angus, VAN 114 Aban	Vancouver	106.0	3,641.39	25,640.57	29,281.96
3	30213408	92 Ave & 176 St, Surrey - Main Abandon	Surrey	77.5	1,538.54	20,937.92	22,476.46
4	30159758	SW MARINE DR AND COLLINGWOOD 219 Aban	Vancouver	1,460.0	35,440.65	19,507.05	54,947.70
5	30159963	W 45&Elm VAN 114 Aban	Vancouver	6,576.0	201,357.52	17,202.37	218,559.89

2009 Five Highest Cost MAIN Retirements

	Work Order Number	Name	Location	Metres of Main Retired	Remaining NBV	Removal /Retirement Costs	Retirement Cost & Remaining NBV Recovered from Customer
1	30282123	Aban219DP at Cap River & Marine Dr, WVAN	West Vancouver	143.0	4,278.78	36,267.31	40,546.09
2	30260100	Downes Station IP Line Break -168DP aban	Abbotsford/Matsqui	19.0	1,281.07	30,066.92	31,347.99
3	30267448	L/S W.1st Ave bet Columbia&Manitoba	Vancouver	196.0	6,307.24	28,971.75	35,278.99
4	30262710	Hwy99 Nordic Hill -Whis- 114 Abandon	Whistler	176.0	4,878.02	25,933.11	30,811.13
5	30216423	W Cordova St @ Thurlow St - main abandon	Vancouver	224.5	34,832.49	22,012.80	56,845.29

155.0 Reference: Asset Loss Report

Exhibit B-1, Application, Appendix E-3

Treatment of Losses

155.1 In 2006, the Supreme Court of Canada issued a decision on the Atco Gas and Pipeline Ltd. related to the treatment of gains on a regulatory asset sale. That decision speaks to the reasons that Atco's gains on sale of an asset were attributable to shareholders as follows:

"68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves: "A utility's customers are not its owners, for they are not residual claimants": MacAvoy and Sidak, at p. 245 (see also p. 237). Ratepayers have made no investment. Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only "the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator" (MacAvoy and Sidak, at p. 245)."

In the excerpt above, the author refers to MacAvoy and Sidak's 2001 article titled *"The Efficient Allocation of Proceeds From a Utility Sale of Assets"* (Exhibit A2-1). That article discusses the conditions and reasons that gains and losses attributable to an asset are attributable to shareholders vs. customers. Page 247 of that article states:

B. Shareholders

The shareholders invest in a company with the expectation that it will use their capital to increase share value. Shareholders realize, however, that value may actually fall due to an incorrect forecast or business decision on the firm's part.

On Page 244 of the MacAvoy and Sidak's document, the article contains the following table:

TABLE 1: EFFICIENT ALLOCATION OF EXTRAORDINARY GAINS AND LOSSES IN REGULATED AND UNREGULATED MARKETS

	Market Change	Regulatory Change
UNREGULATED SERVICE	Shareholder is assigned the risk of extraordinary gains and losses	Not applicable
Regulated Service	Shareholder is assigned the risk of extraordinary gains and losses	Ratepayer is assigned the risk of extraordinary gains and losses

155.2 Based on the above article, please explain why FEU's shareholder has not taken some responsibility for the unrealized losses?

Response:

As discussed in other responses to IRs, there are a number of reasons why the shareholder should not take responsibility for these "losses" and all of these will not be described in this response. In reference to the above Energy Law Journal Article in Exhibit A2-1 (the "Article"), the "losses" in question are not the result of a sale of assets outside of the ordinary course of business as discussed in the article. The "losses" in question are not losses at all; rather, they are unrecovered depreciation on assets which were purchased to provide utility service, but were removed from service in the ordinary course of business due to customer request or for operational and safety reasons. The BCUC's system of accounts provides a mechanism for this unrecovered deprecation to be recovered in rates, which has been determined to be just and reasonable by the Commission and has been followed by the FEU. As discussed below, the cases referenced in the article show that this treatment of unrecovered depreciation is followed by other regulators.

The FEU are unable to draw a direct comparison between the *ATCO* Decision, the Article, and the losses that have resulted from unrecovered depreciation and that are discussed in Appendix E-3 to the Application (Exhibit B-1). Both the *ATCO* Decision and Article are relevant to dispositions (sales) of assets that are outside of the ordinary course of business. Since the dispositions were outside of the ordinary course of business, there were generally no accounting rules defined for the disposition of those assets, and the utilities were required to apply to the Commission to dispose of those assets, as has been the practice of the FEU under Section 52 in similar situations. This is apparent from the following quotes from the Article:

> *"If a utility proposes the sale of certain assets that have risen or fallen substantially in value since their acquisition, the question will naturally arise how regulators should*

allocate those gains or losses among ratepayers and shareholders. Therefore, for regulated energy companies, and indeed for utilities in any of the other traditionally regulated network industries, the allocation of the proceeds from a utility's sale of assets is a policy question of both current and significant topicality, given the current climate of deregulation and structural change."

"In particular, the utility generally has to obtain authorization from its regulator before selling an asset used to produce regulated services."

"This article evaluates that regulation of a utility's purchase and <u>sale decision over assets</u>. Part II examines three reasons why, as part of the regulatory oversight of utilities, regulators constrain the discretion of the utility's management <u>when disposing of the proceeds from an asset sale</u>. Part III analyzes the efficient decision rule for <u>allocating proceeds from a utility's asset sale</u>. Part IV analyzes the competing interests of shareholders and customers <u>with respect to a utility's asset sale</u>." (emphasis added)

The losses that have resulted from unrecovered depreciation cannot be accurately characterized as the result of a "utility's purchase and sale decision over assets." The Article is therefore not directly applicable.

Nor can the FEU's "losses" be accurately characterized as being caused by a "fall [in value] due to an incorrect forecast or business decision on the firm's part" as referenced on page 247 of the Article and quoted in the preamble to the IR. The "losses" are not due to a fall in value at all, but due to the fact that the assets have been abandoned or retired from service earlier than their forecast lives such there has been insufficient time to recover the deprecation during the assets´ life.

Nor can the losses be classified as "extraordinary" losses, as referenced the table from page 244 of the Article and excerpted in the preamble to the IR. As noted above, the "losses" are not truly losses at all, but unrecovered depreciation. They are also not extraordinary in any sense. Even if the "losses" were to be analyzed in terms of the categories in the table, they should not be borne by the shareholder. The table would suggest that where there has been a loss due to a "market change" the shareholder should bear the risk. In the case of the FEU's so-called "losses", there has been no "market change". The reasons for assets to be taken out of service occur in the ordinary course and are expected. It is a fact of using a group system of accounting that some assets will be retired earlier than the average life span for the group and thus result in unrecovered deprecation. Thus, while unrecovered deprecation can be greater than expected due to depreciation rates or estimated retirement cost being too low, the unrecovered depreciation is not due to any particular change in circumstances but is an artifact of the group system of accounting. The Commission's decisions on depreciation rates has also played a part.

Although the article itself does not address the everyday removal of mains, meters and services from use through retirements or abandonments for safety or customer-driven requests, two areas are relevant to the discussion of FEI's under-recovered depreciation.

The first is on page 241 of Exhibit A2-1 and is further discussed in response to BCUC IR 1.155.6:

> *"When there is substantial technological change, an issue requiring consideration is whether, in the depreciation schedule for the utility's asset, the designated useful life is "reasonable." Suppose, as has occurred in the telecommunications industry, that the depreciation schedule is so protracted that the utility cannot recover its costs before technological change renders the partially depreciated asset obsolete and thus worthless. As a first approximation, the amount of undepreciated asset, or the (regulatory) net book value of the asset, consequently becomes unrecoverable. If the proximate cause is not technological change per se, but rather the regulator's constraint on the utility's legitimate recovery of its capital costs over a depreciation schedule that would accurately reflect the useful life of the asset, given reasonable expectations of technological obsolescence in the industry, then the remaining undepreciated value of the asset can be termed as "stranded."*
>
> *For example, suppose that the asset is computer software. Such an asset has a relatively short lifespan in the unregulated world. But suppose that the regulator nonetheless assigns a significantly long lifespan for calculating depreciation to the utility's operation system software for purposes of cost-of-service regulation. <u>The regulator has stranded the utility's asset by mandating an unrealistic lifespan. Meanwhile, ratepayers have benefited from such a depreciation policy. They have paid artificially lower rates that have retarded the utility's legitimate capital recovery at an economically prudent pace. Ratepayers should therefore bear the risk that the true economic lifespan of the utility's asset turns out to be significantly shorter than the regulator's mandated lifespan.</u>" (emphasis added)*

While this example is not directly comparable, the depreciation rate set using the group system of accounting used by the FEU can also be thought of as "unrealistic" in that it is not expected that all assets in a group will have the same lifespan even though an average is adopted for the purpose of calculating depreciation rates. Although the FEU support the use of the group accounting method, in a sense, the depreciation rate is "unrealistic" as it not meant to apply to any particular asset, but is used to recover the cost of the entire asset group over the life of the entire group. There are good reasons for using the group accounting method, as the FEU have explained in other responses, but it essentially uses an artificial life expectancy for ease of administration (i.e. for other bona fide ratemaking purposes). The commentary from the Article quoted above would suggest that ratepayers should bear the risk that the true lifespan of the utility's asset turns out to be shorter than the approved "unrealistic" lifespan.

The second area is the summary of case law included in the Appendix starting at Page 255 of Exhibit A2-1. Although the case law deals with dispositions (sales) of assets outside of the ordinary course of business and each is specific to the circumstances in the case, some of the cases summarized in the Appendix do have relevance to a general understanding of the factors that distinguish particular cases. In particular:

> *"New York Water Service Corp. v. Public Service Commission, 12 A.D.2d 122, 28 N.Y.S.2d 857 (N.Y. App. Div. 2960). The company sold the land in question six years before the rate proceeding in which the issue appeared. The proceeds of the sale, <u>following the accepted accounting principles of the state</u>, were to be credited to a depreciation reserve account. Any losses that occurred were to be recovered through this same account from the ratepayers, albeit over time. With the formation of the account, and by including both the profits and the losses in this account, the investors were not at risk for losing their investments as the ratepayers paid for the market value of the asset, albeit over time through the depreciation. This case is different from most with regard to the sale of land assets in that the asset was "paid for" by the ratepayers. As a result<u>, the risk was transferred to the ratepayers through the accounting procedures."</u> (emphasis added)*

> *"Casco Bay Lines v. Public Utilities Commission, 390 A.2d 483 (Me. 1978). In 1974, Casco realized a net gain of $28,396.47 upon the sale of three vessels as depreciable property. The Supreme Judicial Court held that ratepayers were entitled to the proceeds minus 10% given to the shareholders as incentive. The court approvingly noted that the Maine Public Utilities Commission treated the gains as follows: "If there is a gain <u>from the sale of depreciable property, it indicates that depreciation has been miscalculated</u> and that the ratepayers have been overcharged."" (emphasis added)*

> *"California Public Utilities Comm'n, Re Suburban Water System, 149 P.U.R.4th 15, Decision 94-01-028, Application 90-10-029 (Cal. P.U.C. 1994). The land on which two of Suburban's operations pumps were located had in-creased in value as a result of the increase in land value in that area. As a result, Suburban determined that the best use of the land was to sell it and use the proceeds for other purposes. As it had two operating pumps on the land, Suburban negotiated the sale such that it retained access to the pumps and they remained in place. <u>Based on an extensive record of cases in other jurisdictions, Suburban developed a proposed model under which gains on depreciable</u>*

assets (plant) would go generally to ratepayers and gains on non-depreciable assets (land) would go generally to shareholders following the mitigation of any adverse impact to the ratepayers. The California PUC agreed with Suburban's recommendation be-cause ratepayers pay depreciation expenses in rates, and thus return to investors over time the capital spent for plant and equipment, and any gain or loss is re-corded against net plant. In addition, ratepayers neither pay depreciation on land, nor do they bear the risk of loss on sale, hence ratepayers do not reimburse the capital contributed by investors for land purchase. The California PUC also argued that the Uniform System of Accounts required this disposition of gains and losses for plant, equipment, and land. As a result, in this case, the California PUC concluded that shareholders had the right to the gain in this sale of land be-cause it was they who bore the risk of capital loss. To the extent in this case the ratepayers had some risk from the operation of two booster pumps on the property, that utility service continued unchanged and was unaffected by the sale, except to the extent that ratepayer burden had been reduced." (emphasis added)

"California Public Utilities Commission, Re Pacific Gas and Electric, A.96-08-001; A.96-08-006; A.96-08-007; Decision No. 97-11-074 (Cal. P.U.C. 1997). Following the adoption of Preferred Policy Decision and AB 1890, PG&E wanted to sell some property. PG&E explained that the gain or loss on sale of depreciable assets has traditionally been flowed back to ratepayers through the depreciation reserve, while gains or losses related to non-depreciable property have been allocated to shareholders. PG&E believes, however, that land must now be treated as depreciable property because of the language adopted in the Preferred Policy Decision and AB 1890. Therefore, PG&E proposed that all gains and losses realized through sale, spinoff, or appraisal of generation assets, including land, should flow back to ratepayers by way of the transition cost balancing account. Conceptually, the Commission agreed that the gain or loss resulting from sale of assets, including land, should now flow through the transition cost balancing account, but they saw no reason to adopt Edison's approach of amortizing any gain over the remaining months of the transition period. The gain should simply be credited to the transition cost balancing account and the appropriate subaccount closed out. As a separate matter, they were in the process of authorizing auctions for assets undergoing divestiture." (emphasis added)

The cases described above support the view that, for depreciable assets, to the extent any gain or loss should be attributable to either inadequate or accelerated recovery of past depreciation, the ratepayers are responsible to return depreciation to investors over time for the capital spent for plant and equipment. As described in the cases, this treatment is prescribed by accounting rules which the utilities and their regulators rely on for guidance, in the same manner as the

BCUC. With respect to treatment of asset "losses" on depreciable property, the accounting rules referred to in the cases match those of the BCUC. The FEU's treatment of losses caused by under-recovered depreciation is in accordance with the BCUC's Uniform System of Accounts as quoted on page 290 of the Application and is consistent with the treatment reported in the cases described above.

The *ATCO* Decision is relevant in the sense that it recognizes and reconfirms that the Commission's obligation to set just and reasonable rates must necessarily account for the recovery of the utility cost of service over time. The utility cost of service includes appropriate depreciation expense for depreciable assets, and denying recovery of unrecovered depreciation would result in rates that have been insufficient to meet the requirements of section 59(4) of the UCA.

155.3 As some of the losses accumulated during the PBR period, should some recoveries during that period be shared between the ratepayers and shareholders?

Response:

No. Please see the responses to BCUC IRs 1.155.2 and 1.151.10.

155.4 Has FEU ever taken gains realized on the sale/disposal of a regulatory asset?

Response:

Please see the response to BCUC IR 1.136.2.

155.5 On page 241, the same article discusses the impact of depreciation rates when regulators impose rates that do not match the economic life of an asset as follows:

For example, suppose that the asset is computer software. Such an asset has a relatively short lifespan in the unregulated world. But suppose that the regulator nonetheless assigns a significantly long lifespan for calculating depreciation to the utility's operation system software for purposes of cost-of-service regulation. The regulator has stranded the utility's asset by mandating an unrealistic lifespan. Meanwhile, ratepayers have benefited from such a depreciation policy. They have paid artificially lower rates that have retarded the utility's legitimate capital recovery at an economically prudent pace. Ratepayers should therefore bear the risk that the true economic lifespan of the utility's asset turns out to be significantly shorter than the regulator's mandated lifespan.

In the case of FEI, two requests to change certain depreciation rates were made but not approved by the Commission (between 1999 and 2007). An analysis of the rate impact of those studies and the difference between actual deprecation and deprecation that would have been charged (assuming both the 1999 and 2007 depreciation studies had been approved) is included below. Supporting calculations (in electronic format) for this table are included in Attachment 1 to this document.

In this analysis below, column A indicates the addition depreciation that the FEI would have charged customers if the depreciation studies had been approved. Column B indicates the unrealized losses incurred, by asset class as discussed in Appendix E-3 of the Application. In the case of asset class 474-00 House Regulator and Meter Installation as well as class 478 Meters, the unrealized losses incurred far exceeded the additional depreciation requested by the Utility. This difference amounted to $40,743k. The requested depreciation for the other two asset classes would have sufficiently offset losses on assets if the requests were approved.

No.	$'000 Asset Account	Dep'n difference (sum of 2000-1999)	unrealized losses (Exhibit B-1, Appendix E-3)	removal costs less salvage (Exhibit B-1, Appendix E-3)	unrealized losses up to Dep'n difference	requested Dep'n exceeds losses by:
55	473-00 Services	56,032	27,800	45,800	27,800	$0
56	474-00 House Regulator & Meter Installation	3,153	2,400	5,600	3,153	-$29,247
57	475-00 Mains	21,075	5,500	4,800	5,500	$0
65	478 Meters	6,905	18,400	2,100	6,905	-$11,495
		87,165	**84,100**	**58,300**	**43,357**	**40,743**

155.6 Please confirm the calculations in this spreadsheet (see Attachment 1) and table above are accurate.

Response:

FEI has reviewed the spreadsheet in Attachment 1, recalculated the depreciation expense based on a correction to depreciation rates for asset classes 474 and 478 for the years 2000 through 2003, and included the revised spreadsheet as Attachment 155.6. Although the FEU do not agree with some of the embedded assumptions in this analysis as explained below, a revised table follows:

Line No.	Account	dep'n difference (sum of 2000-1999)	unrealized losses (Exhibit B-1, Appendix E-3)	unrealized losses up to dep'n difference	losses exceeds requested depreciation by:
55	473-00 Services	56,032	27,800	27,800	$0
56	474-00 House Regulator & Meter Installation	5,840	32,400	5,840	$26,560
57	475-00 Mains	21,075	5,500	5,500	$0
65	478 Meters	9,998	18,400	9,998	$8,402
		92,945	**84,100**	**49,138**	**34,962**

The FEU understand that the table above is intended to demonstrate what the unrecovered depreciation would be today had the revised depreciation rates been approved for these four asset classes. However, the additional depreciation expense of $92.945 million that would have been recovered from customers had the recommended depreciation rates been implemented would not have resulted in an equal reduction in the unrecovered depreciation expense (losses) that were recorded. In order to calculate the amount that the unrecovered depreciation expense would have been reduced by, the recorded "loss" by year for the specific assets retired must be recalculated taking into account the revised depreciation rates. A high level analysis by FEI indicates that the "losses" of $84.1 million would have been reduced by approximately $7.2 million or 8 percent. When added to the approximate $8 million reduction in reported unrecovered depreciation that was discussed for asset class 474 in response to BCUC IR 1.151.10, overall "losses" would have been reduced by approximately $15 million and not the $92.9 million indicated in the table. In summary, the $92.9 million represents the additional depreciation that would have been collected from customers over the period from 2000 to 2009 had the revised depreciation rates been implemented; additionally these revised depreciation rates combined with the reclassified depreciation for asset class 474 would have reduced the losses by approximately $15.2 million across all asset classes, as shown below.

Unrecovered Depreciation ($ thousands)	Actual	Adj	Revised
473-00 Services	27,800	(3,029)	24,771
474-00 House Regulator & Meter Installation	32,400	(10,314)	22,086
475-00 Mains	5,500	(287)	5,213
478 Meters	18,400	(1,587)	16,813
	84,100	(15,216)	68,884

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.

FEI believes that the amounts characterized as losses (representing under-recovered depreciation) are reasonable in light of the deferral of the requested increases in depreciation rates, the group accounting method involved in determining the under-recovery of depreciation, and the average life of the assets involved. These amounts represent the allocation of the cost of providing utility service and are therefore 100 percent recoverable from customers.

155.7 At the time when depreciation rates were estimated and requested for approval in 1999 and 2007, did management make an error in estimating depreciation rates?

Response:

No, management did not make an error in estimating depreciation rates. As discussed in the response to BCUC IR 1.137.8, as with any of the many estimates that are involved in determining accounting income, there will be some variation between the amounts that have been estimated and the actual amounts incurred. It is not expected that individual estimates will be 100 percent accurate but rather that they will result in a reasonable approximation. This estimating process does not change the underlying nature of the costs to be recovered – the original cost of the asset and the costs of removal and abandonment of assets that have been used to provide utility service. Therefore, these costs are recoverable from customers.

Also, as stated in the Application (Exhibit B-1), on page 291, adjustments to depreciation rates are required on a regular basis to reflect changes in the expected lives of assets. The past practice of deferring depreciation rate increases has contributed to losses in the form of under-recovered depreciation being accumulated. Although, as discussed in the response to BCUC IR 1.155.6, the approval of previously recommended increases in depreciation rates would not have resulted in the elimination in the balance of under-recovered depreciation that existed at the end of 2009, the changes to rates were designed to address the recovery of those losses over the expected lives of the assets. This is consistent with accepted depreciation methodologies and regulatory accounting practices.

155.8 As the losses of $40,743 resulted due to factors other than regulator constraint on FEI, are these losses attributable to the shareholder's?

<u>Response:</u>

The $40,743 figure is incorrect. Please see the response to BCUC IR 1.155.6. The unrecovered depreciation as of the end of 2009 should not be attributable to the shareholder. The under-recovered depreciation resulted from many factors, and some amount of under-recovered depreciation is expected given the past practice of not implementing recommended changes to depreciation rates and the current age of FEI's assets. Please see the responses to BCUC IRs 1.148.4, 1.151.10, 1.155.2 and 1.155.6 for a further discussion of this issue.

156.0 Reference: Bill Impact and Tariff

Exhibit B-1, Application, Appendix F-2

156.1 Please complete the Delivery Charge and Cost of Gas table below for FEI, FEVI, FEW and Fort Nelson for 2006-2010for residential customers. Also provide the tables in fully functional electronic format.

Delivery Charge and Cost of Gas - FEI

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2012 Forecast
Basic Charge								
Delivery Charge ($/GJ)								
Cost of Gas ($/GJ)								
Total Cost ($/GJ)								

<u>Response:</u>

Please refer to BCUC IR 1.156.1.1 for the fully functional electronic format.

<u>Notes/Assumptions:</u>

1. For all service areas, 2006-2011 rates reflect the approved rates as of January 1 of the respective year.
2. Rates shown below exclude riders, taxes and any other fees (e.g. Carbon Tax).
3. FEVI Commodity and FEW Variable charges include both Delivery and Cost of Gas.
4. Commission Order No. G-35-09, dated April 7, 2009, directed FEW to establish unbundled rates upon the later of January 1, 2010 or the completion of the conversion project. Thus only January 1, 2010 and onward rates has Gas Cost Recovery Charge per GJ and Delivery Charge per GJ as separate items.
5. The 2012 and 2013 Basic Charge rates reflect the monthly equivalent for comparison purposes. Effective January 1, 2012 Basic Charge will be billed on a daily basis in all service areas.

6. Cost of Gas for 2012 and 2013 for FEI, FEW, Fort Nelson are not forecasted due to the volatile nature of natural gas prices. The 2012 and 2013 rates are kept the same as 2011.

7. Total Cost per GJ figures represent the effective rates based on average consumption values for each service area. Detailed calculations for each entity (generic example shown below) can be found in the attached spreadsheet.

   *(Monthly Basic Charge * 12 months) / Annual Average Consumption + Delivery Charge*[26] *per GJ + Cost of Gas per GJ + Midstream Charge per GJ*

[26] Commodity Charge for FEVI and Variable Charge for FEW.

Delivery Charge and Cost of Gas - FEI Average Consumption (GJ/year): 95

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Basic Charge	$ 11.12	$ 10.94	$ 11.13	$ 11.99	$ 11.84	$ 11.84	$ 11.84	$ 11.84
Delivery Charge ($/GJ)	$ 2.781	$ 2.736	$ 2.783	$ 2.998	$ 3.179	$ 3.275	$ 3.531	$ 3.856
Midstream Charge ($/GJ)	$ 0.613	$ 0.859	$ 1.209	$ 0.942	$ 1.642	$ 1.340	$ 1.340	$ 1.340
Cost of Gas ($/GJ)	$ 9.774	$ 7.662	$ 6.926	$ 7.536	$ 4.953	$ 4.568	$ 4.568	$ 4.568
Total Cost ($/GJ)	$ 14.573	$ 12.639	$ 12.324	$ 12.991	$ 11.270	$ 10.679	$ 10.935	$ 11.260

Delivery Charge and Cost of Gas - FEVI Average Consumption (GJ/year): 59

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Basic Charge	$10.50	$10.50	$10.50	$10.50	$10.50	$10.50	$10.50	$10.50
Commodity Charge ($/GJ)	$13.230	$13.715	$13.775	$14.325	$14.325	$14.325	$14.325	$14.325
Total Cost ($/GJ)	$15.366	$15.851	$15.911	$16.461	$16.461	$16.461	$16.461	$16.461

Delivery Charge and Cost of Gas - FEW Average Consumption (GJ/year): 90

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
Basic Charge	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
Variable Charge ($/GJ)	$13.855	$13.855	$13.855	$23.015	$18.672	$16.263	$16.503	$17.786
Delivery Charge	-	-	-	-	$11.981	$10.440	$10.680	$11.963
Cost of Gas	-	-	-	-	$7.882	$5.823	$5.823	$5.823
Total Cost ($/GJ)	$14.855	$14.855	$14.855	$24.015	$19.672	$17.263	$17.503	$18.786

Delivery Charge and Cost of Gas - FEFN Average Consumption (GJ/year): 140

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2013 Forecast
First 2 GJ /month (Minimum Charge)	$20.80	$17.85	$19.19	$23.01	$20.35	$19.59	$20.20	$20.36
Delivery Charge (2 GJ)	$ 4.110	$ 4.110	$ 5.450	$ 7.730	$ 7.730	$ 9.560	$ 10.166	$ 10.330
Cost of Gas (2 GJ)	$ 16.690	$ 13.740	$ 13.740	$ 15.280	$ 12.620	$ 10.030	$ 10.030	$ 10.030
Next 28 GJ /month								
Delivery Charge ($/GJ)	$1.202	$1.202	$1.595	$2.000	$2.000	$2.410	$2.570	$2.612
Cost of Gas ($/GJ)	$8.342	$6.868	$6.868	$7.640	$6.309	$5.015	$5.015	$5.015
Excess of 30 GJ /month								
Delivery Charge ($/GJ)	$1.167	$1.167	$1.549	$1.942	$1.942	$2.340	$2.502	$2.501
Cost of Gas ($/GJ)	$8.342	$6.868	$6.868	$7.640	$6.309	$5.015	$5.015	$5.015
Total Cost ($/GJ)	$9.691	$8.217	$8.657	$9.960	$8.629	$7.831	$8.016	$8.065

156.1.1 Using the data from the previous question, please complete Delivery Charge and Cost of Gas as a percentage of Total Cost table for FEI, FEVI, FEW and Fort Nelson for 2006-2010. Also create a stacked bar graph showing the delivery charge and the cost of gas as a percentage of the total. Also provide the tables in fully functional electronic format.

Delivery Charge and Cost of Gas as a percentage of Total Cost - FEI

Year	2006 Approved	2007 Approved	2008 Approved	2009 Approved	2010 Approved	2011 Approved	2012 Forecast	2012 Forecast
Delivery Charge as a % of Total								
Cost of Gas as a % of Total								
Total								

Response:

The requested tables are provided below and the fully functioning electronic format is provided in Attachment 156.1.1.

Notes/Assumptions:

1. For all service areas, 2006-2011 rates reflect the approved rates as of January 1 of the respective year.
2. Rates shown below exclude riders, taxes and any other fees (e.g. Carbon Tax).
3. FEVI Commodity and FEW Variable charges include both Delivery and Cost of Gas.
4. Commission's Order No. G-35-09, dated April 7, 2009, directed FEW to establish unbundled rates upon the later of January 1, 2010 or the completion of the conversion project. Thus only January 1, 2010 and onward rates has Gas Cost Recovery Charge per GJ and Delivery Charge per GJ as separate items.
5. The 2012 and 2013 Basic Charge rates reflect the monthly equivalent for comparison purposes. Effective January 1, 2012 Basic Charge will be billed on a daily basis in all service areas.

6. Cost of Gas for 2012 and 2013 for FEI, FEW, Fort Nelson are not forecasted due to volatile nature of natural gas prices. The 2012 and 2013 prices are kept same as 2011 values.

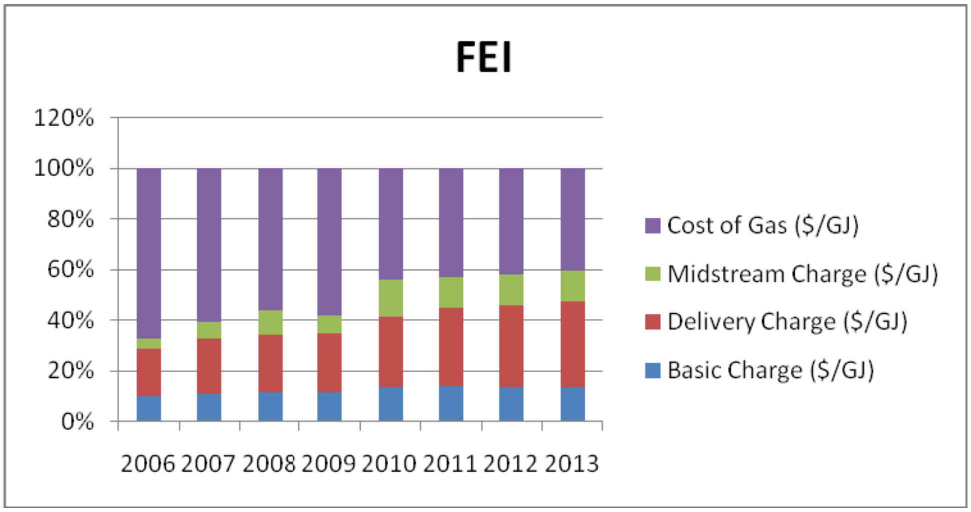
7. Fort Nelson Delivery Charge and Commodity Cost Recovery Charge per GJ are presented as effective rates due to the tiered rate structure.

Delivery Charge and Cost of Gas - FEI			Average Consumption (GJ/year):				95	
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Basic Charge ($/GJ)	9.6%	10.9%	11.4%	11.7%	13.3%	14.0%	13.7%	13.3%
Delivery Charge ($/GJ)	19.1%	21.6%	22.6%	23.1%	28.2%	30.7%	32.3%	34.2%
Midstream Charge ($/GJ)	4.2%	6.8%	9.8%	7.3%	14.6%	12.5%	12.3%	11.9%
Cost of Gas ($/GJ)	67.1%	60.6%	56.2%	58.0%	44.0%	42.8%	41.8%	40.6%
Total Cost ($/GJ)	100%	100%	100%	100%	100%	100%	100%	100%

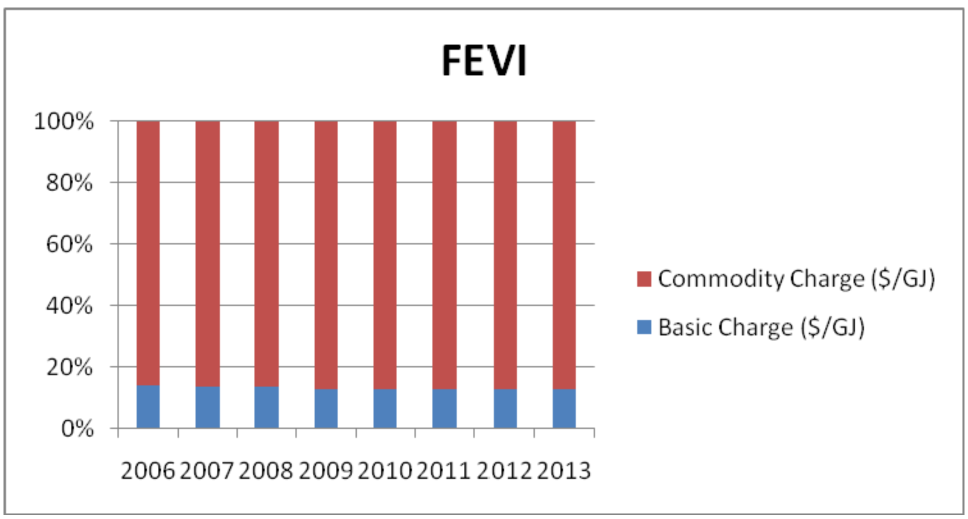
Delivery Charge and Cost of Gas - FEVI			Average Consumption (GJ/year):				59	
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Basic Charge ($/GJ)	13.9%	13.5%	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%
Commodity Charge ($/GJ)	86.1%	86.5%	86.6%	87.0%	87.0%	87.0%	87.0%	87.0%
Total Cost ($/GJ)	100%	100%	100%	100%	100%	100%	100%	100%

Delivery Charge and Cost of Gas - FEW			Average Consumption (GJ/year):				90	
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Basic Charge ($/GJ)	6.7%	6.7%	6.7%	4.2%	4.8%	5.8%	5.7%	5.3%
Variable Charge ($/GJ)	93.3%	93.3%	93.3%	95.8%	-	-	-	-
Delivery Charge	-	-	-	-	57.4%	60.5%	61.0%	63.7%
Cost of Gas	-	-	-	-	37.8%	33.7%	33.3%	31.0%
Total Cost ($/GJ)	100%	100%	100%	100%	100%	100%	100%	100%

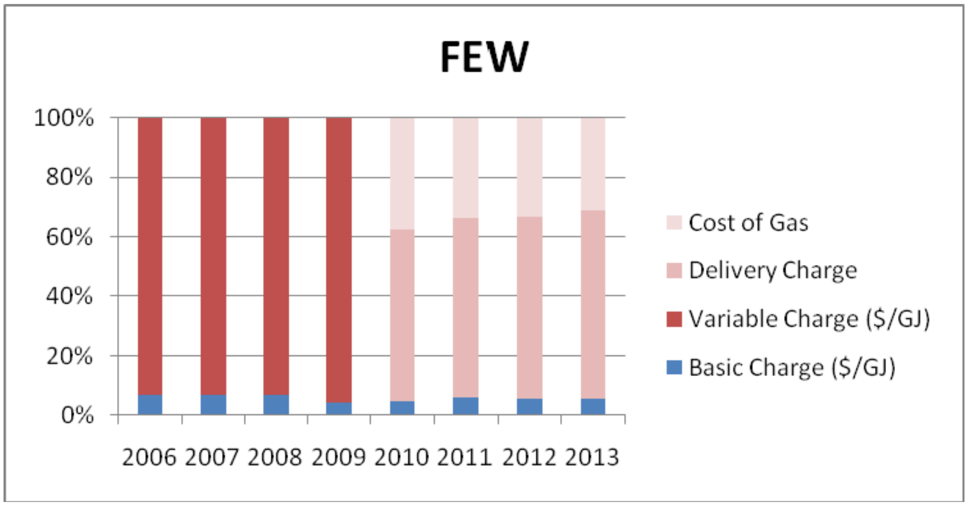
Delivery Charge and Cost of Gas - FEFN			Average Consumption (GJ/year):				140	
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Average Consumption: 140GJ								
Minimum Charge ($/GJ)	18.4%	18.6%	19.0%	19.8%	20.2%	21.4%	21.6%	21.6%
Delivery Charge ($/GJ) (up to 28 GJ/month)	10.3%	12.1%	15.3%	16.6%	19.2%	25.5%	26.6%	26.8%
Cost of Gas ($/GJ)	71.3%	69.3%	65.7%	63.6%	60.6%	53.1%	51.8%	51.5%
Total Cost ($/GJ)	100%	100%	100%	100%	100%	100%	100%	100%

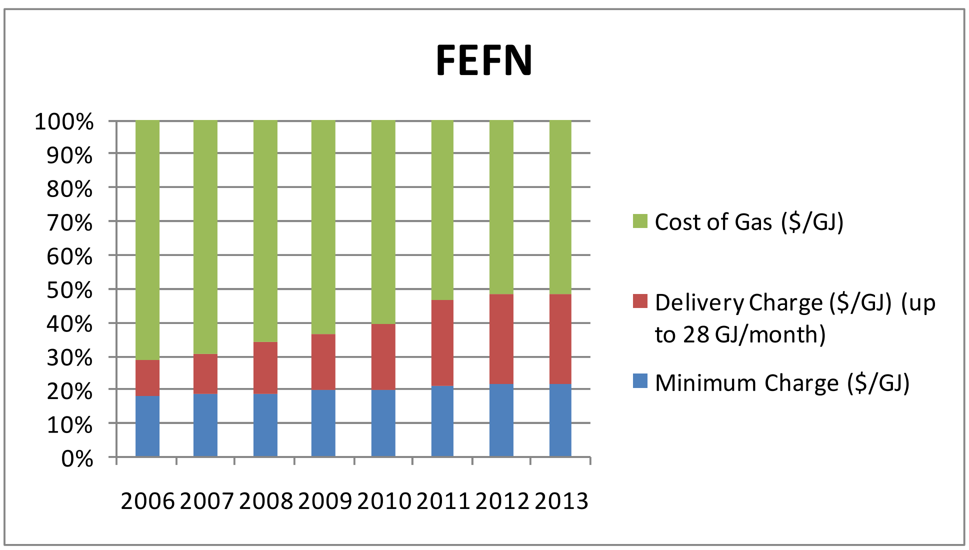


FEI
120%
100%
80%
60%
40%
20%
0%
2006 2007 2008 2009 2010 2011 2012 2013
Cost of Gas ($/GJ)
Midstream Charge ($/GJ)
Delivery Charge ($/GJ)
Basic Charge ($/GJ)



FEVI
100%
80%
60%
40%
20%
0%
2006 2007 2008 2009 2010 2011 2012 2013
Commodity Charge ($/GJ)
Basic Charge ($/GJ)


FEW
100%
80%
60%
40%
20%
0%
2006 2007 2008 2009 2010 2011 2012 2013
Cost of Gas
Delivery Charge
Variable Charge ($/GJ)
Basic Charge ($/GJ)


FEFN
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
2006 2007 2008 2009 2010 2011 2012 2013
Cost of Gas ($/GJ)
Delivery Charge ($/GJ) (up to 28 GJ/month)
Minimum Charge ($/GJ)

157.0 Reference: Thermal Energy

Exhibit B-1, Application, Appendix G, Section 2.4.1, p. 4

Thermal Energy – Direct Costs

Table G-2: Thermal Energy Projects are in Development Stages

	2010			2011		
	NSA	**Actual**	**Variance**	**NSA**	**Projected**	**Variance**
Direct Costs	0	1,196	1,196	0	11,750	11,750
Sales & Marketing	1,000	1,435	435	1,500	1,550	50
Overhead Allocation	500	500	0	500	500	0
AFUDC	0	82	82	0	100	100
Tax	-428	-682	-254	-530	-543	-13
	1,073	2,530	1,458	1,470	13,357	11,887

"The direct costs include feasibility assessment, design, equipment and construction of the various thermal energy solutions. These costs vary with the number, nature and development stage of projects. As such, an approved spending amount was not specified for 2010 and 2011 and a variance is therefore not reported. The increase in 2011 over 2010 is attributable to increased market interest in certain sectors such as schools and hospitals, with some projects beginning construction in 2011. These projects will be brought forward for BCUC approval in 2011."

157.1 Please provide a breakdown of the 2010 Actual and 2010 and 2011 Projected Direct Costs by year, thermal energy solutions project and resource.

<u>Response:</u>

The FEU are submitting this response on a confidential basis under separate cover as the response reveals confidential customer information related to projects currently under negotiations and would adversely affect commercial negotiations if disclosed.

158.0 Reference: Thermal Energy

Exhibit B-1, Application, Appendix G, Section 2.4.2,p. 4;

New energy solutions for BC YouTube Video

http://www.youtube.com/watch?v=JQ4sD_zMxlc

Thermal Energy – Sales and Marketing O&M and Business Development

"Sales and marketing O&M includes the labour of the 12 employees in Thermal Energy Services in 2011 as well as the direct labour charged through timesheets from individuals in other areas of the Companies. The costs also include contributions to industry associations of $15 thousand in 2011.3 As agreed to in the NSA, these costs were budgeted at $1 million in 2010 and $1.5 million in 2011. As shown in Table G-2, the O&M and Business Development costs captured in the deferral account were $1.4 million in 2010 and are projected to be $1.6 million in 2011."

158.1 Was the cost of creating the "New energy solutions for BC" video included in the Thermal Energy Services Deferral Account? If not, please explain why not?

Response:

The New Energy Solutions Video was developed and paid for in 2009 for $19,733. This was before the Negotiated Settlement Agreement for 2010-2011 and the associated Thermal Energy Services Deferral Account were established. Approximately $17,000 was charged to FEI, and the balance to FEVI.

Although the deferral account had not yet been set up, the FEU are of the opinion the video and similar communication costs were appropriately allocated to all customers. Firstly, the video contains information pertinent to customers about natural gas service, natural gas infrastructure, energy efficiency and conservation, and it discusses how the FEU is working to meet the current and future energy needs of BC customers and communities. Secondly, natural gas plays an integral role in each of the renewable thermal energy projects presented in the video.

Note that this video was initially made available from the www.fortisbc.com main web page. Placement of the video on YouTube allows the FEU to extend viewership at no additional cost.

158.2 Please provide a breakdown of cost of the "New energy solutions for BC" video by year and resource. Include the labour cost of all FEU employees involved in the creation of the video.

Response:

Please see the response to BCUC IR 1.158.1. Development of the video was outsourced and no labour costs for FEU's employees were charged to it.

158.3 Please provide the direct labour charged through timesheets from individuals in other areas of the Companies by cost centre, hours and average rate.

Response:

This response also addresses BCUC IR 1.158.4.

The FEU interpret this request to mean the direct labour charged to the sales and marketing general O&M (the $1.435 million in actual costs in 2010) within the Thermal Energy Deferral Account as outlined in the Application (Exhibit B-1), Appendix G, Table G-2, page 4 by employees outside of the Thermal Energy Solutions group. Table 1 below shows the direct labour charged by both Thermal Energy Solutions employees and other employees.

Table 1: Labour Charges for Thermal Energy Employees and Other Employees in 2010

		2010 Actuals		
		Labour	Labour	Average
		Cost	Hours	Rate
Cost Ctr	Cost Centre Title	$(000)	#	$
2131	Thermal Energy Solutions	867	9,515	91
	Total Thermal Energy Services	867	9,515	91
2059	Lg Comm'l & Indust Energy Solutions	1	10	66
2060	Interior Energy Solutions	34	485	70
2066	Mainland Energy Solutions	94	1,264	75
2304	Community Energy Solutions	16	197	83
6157	Vancouver Island Energy Solutions	47	644	73
	Total Other	192	2,600	74
	Grand Total	1,060	12,115	87

Included within the O&M and Business Development costs captured within the Thermal Energy Deferral Account are costs for travel, training, meals and accommodation for employees within the Thermal Energy Services Group related to Thermal Energy Services business development activities. These costs are shown in Table 2 below..

Table 2: O&M Costs for Travel, Training, Meals, Accommodation and Other Expenses Associated with the 12 Employees in the Thermal Energy Solutions 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

Together, Tables 1 and 2 provide a complete account of the direct O&M and Business Development costs charged to the Thermal Energy Deferral Account in 2010, which in total was $1.435 million.

158.4 Do the Sales and marketing O&M costs include the travel, training, meals, accommodation and other expenses associated with the 12 employees in Thermal Energy Services? If yes, please provide a breakdown by year and resource. If not, please explain why not and provide the costs by year and resource.

Response:

Please refer to BCUC IR 1.158.3.

159.0 Reference: Thermal Energy

Exhibit B-1, Application, Part 5.3.18.2 and Appendix G, Section 2.4.3, pp. 4-5

Thermal Energy – Overhead Allocation

"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." (Exhibit B-1, pp. 4-5)

"Based on the review, FEI has estimated that a charge of approximately $0.5 million for both 2012 and 2013 be included as a recovery of overheads for the benefit of FEI and its ratepayers. This charge represents the expected administrative costs of supporting the AES business." (Exhibit B-1, p. 776)

159.1 Please provide the review of which services should be included in this administrative charge and how the charges for 2012 and 2013 were calculated.

Response:

As outlined on pages 275 and 276 of the Application (Exhibit B-1), the following is included in the overhead allocation to Thermal Energy Services:

- Executive: time to review current status of projects, monitor status of projects and reviewing and approving potential projects.
- Finance: management and financial reporting and accounts payable.
- Regulatory affairs: reviewing cost of service models, tariffs and project management.
- Human Resources: recruiting and compensation and benefits.
- Information technology: IT support to existing employees charging time directly to the AES deferral.
- Facilities: allocation of facilities costs for employees charging directly into the AES deferral account. The facilities include space in the Surrey Operations Centre, Garbally/Langford and the Burnaby facility.

Please see the response to BCUC IR 1.78.1 for a review of the costs included in this overhead allocation.

159.2 Does the overhead allocation include the operating and maintenance costs associated with desktops/laptops and furniture for employees in Thermal Energy Services? If not, why not?

Response:

Yes, the overhead allocation includes costs for desktops/laptops and employee furniture.

159.3 Does this charge include any time of management, senior management, travel, training or business development charges recorded directly within the accounts of FEI?

Response:

As outlined in BCUC IR 1.159.1, the time component included time of management and senior management. Any incremental costs for travel, training or business development would be charged directly to the Thermal Energy deferral account. Please also see the FEU's response to BCUC IR 1.78.1 for a review of overhead allocation to the Thermal Energy Deferral Account.

160.0 Reference: Thermal Energy

Exhibit B-1, Application, Appendix G, Section 2.4.2,p. 4;

Thermal Energy – Sales and Marketing O&M and Business Development

160.1 Please confirm that time, travel, meals, accommodation, promotion and other associated costs related to Vice President (VP) of Energy Solutions and External Relations involvement in the activities below have been charged to the Thermal Energy Deferral Account and provide the amount of this allocation. If not, please explain why not. Also provide the 2010-2013 VP of Energy Solutions and External Relations cost charge to the Thermal Energy Deferral account and other approved alternative energy project, by year and resource. Consider the following excerpts in preparing your response.

1. **2010 CDEA Conference**

   June 23rd District Energy (DE) Utility Workshop
   2010 Keynote Speaker – Doug Stout
   http://cdea.ca/events/past-conferences-1/2010-conference-presentations/2010-keynote-speakers/

2. **Quesnel Community Energy System the first of its kind in North America**

   7/7/2010 QUESNEL, B.C.

   QUESNEL, B.C. –
   "The City of Quesnel and Terasen Gas have signed a letter of intent (LOI) to conduct final feasibility work on a unique renewable energy system in Quesnel in cooperation with West Fraser Timber Co. Ltd. and BC Hydro

   "Community-based energy solutions allow us to incorporate new or alternative technologies - in this case, recovered heat and sawmill residuals - as part of our regulated energy service offerings," said Doug Stout, Vice President of Energy Solutions and External Relations at Terasen Gas and FortisBC."
   http://www.terasenenergyservices.com/News/Pages/QuesnelCommunityEnergySystem.aspx

3. **Central Okanagan School District to save energy and money with new Terasen Gas geoexchange system**

   "SURREY, BC, Oct. 12 /CNW/ - Terasen Gas and School District 23 Central Okanagan, have signed a deal to retrofit and operate a $650,000 geoexchange system, expected to be operational in 2010, at Helen Gorman Elementary School in West Kelowna. The geoexchange system will help the school manage its energy costs and reduce its carbon footprint.

   "As one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings, our deal with the Central Okanagan School District will help them use energy efficiently and benefit the environment," said Doug Stout, Vice President, Energy Solutions and External Relations at Terasen Gas and FortisBC"
   http://www.cnw.ca/en/releases/archive/October2010/12/c9816.html

4. **November 23, 2010 Clean Energy Biomass-Fuelled Projects**
   "As one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings, providing British Columbians with biogas makes good sense and is a natural extension of the piped energy services we've delivered for over a century," says Doug Stout, Vice President, Energy Solutions and External Relations at Terasen Gas and FortisBC.
   http://www.marketwire.com/press-release/BC-Bioenergy-Network-Invests-With-Terasen-Gas-Two-Innovative-Clean-Energy-Biomass-Fuelled-1358219.htm

Response:

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"). This allocation is intended to capture a portion of the costs for activities such as the four noted in this information request. Please see the response to BCUC IR 1.78.1 for a review of the overhead allocations included in the $0.5 million, including time for the VP of 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.

Please note that the audiences for each of these four activities are likely to include both current and future natural gas customers of the FEU. Examples of such customers include Central

Heat, Lonsdale Energy Corporation, Corix (Dockside Green), other members of the Canadian District Energy Association and school districts throughout B.C. An aspect of these projects that remains important to our gas customers is ensuring that natural gas, as a firm, proven and low carbon energy source, remains a part of the energy mix in these types of projects wherever it is available. 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:

- A large part of the District Energy Utility workshop presentation was focused on natural gas solutions and the importance of natural gas as part of the energy mix.
- The Quesnel Community Energy System highlights the type of service that existing customers are seeking from the FEU in order to meet their future energy needs. The shifting desire to these types of energy solutions has implications for the FEU's existing and future natural gas customers.
- The Central Okanagan School District Press release similarly highlights the types of service that our existing customers are seeking. This project will result in energy efficiency and carbon emission reductions for our natural gas customers and proposes that natural gas remain a part of the energy mix as a firm, supplementary fuel to the proposed renewable thermal energy services.
- The BC BioEnergy Network press release features two projects. In one project, a potential future combined heat and power project, the FEU's participation will ensure that natural gas continues to be a part of the energy mix as a back-up or supplementary fuel. Similar future projects in other areas may include natural gas as a primary fuel. The other project mentioned in the press release is a biogas project which is entirely related to natural gas service.

161.0 Reference: Compressed Natural Gas and Liquefied Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, p. 2; "Natural gas vehicles" YouTube Video

http://www.youtube.com/watch?v=L8yO7TJQ-wg

CNG and LNG

"The O&M resources that were approved in our previous RRA for 2010-2011 are sufficient to manage the forecast growth of the NGV fueling business for the 2012-2013 test period. As a result, there is no incremental O&M requirement for the ES&ER group being proposed at this time specifically for NGV. As agreed to in Item 14 (b) of the NSA, "the marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates."4 The O&M costs in other departments are detailed in Section 5 of this Appendix.5"

161.1 Please provide a breakdown of cost of the "Natural gas vehicles" video by year and resource. Include the labour cost of all FEU employees involved in the creation of the video.

Response:

The total cost of the referenced video was $12,180, including pre-production, production, post-production and HST. There was no material labour cost incurred by the FEU's employees as the video production was outsourced to a third-party production company.

This investment supports the developing NGV market, which will provide material benefits to all of our customers.

162.0 Reference: Compressed Natural Gas and Liquefied Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, pp. 14-15

CNG and LNG

"FEI has adopted the same approach in this RRA, as the promotion of NGV represents a part of FEI's core natural gas business. The information set out below breaks out the O&M costs within the ES&ER department for information purposes only.

The O&M costs presented below are estimated costs, rather than actual amounts for the NGV costs within the ES&ER department. 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."

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	$0	N/A	$50,000
Total:	**4.0**	**$480,275**	**4.0**	**$551,637**

162.1 Please confirm FEI will track and report actual O&M amounts for NGV separately for the 2012-2013 period?

Response:

No, FEI believes that continuing the current level of tracking and reporting detail is the most appropriate course of action.

Commission Order No. G-141-09, which approved the NSA resulting from the FEI 2010-2011 RRA, did not require FEI to track the actual amounts that correspond to the estimated costs provided above. These estimates were provided for informational purposes so as to give an order-of-magnitude approximation of the O&M expenditures incurred over the 2010-2011 period in regards to developing NGV programs. FEI has adopted the same approach in this RRA as in our previous RRA and FEI does not intend to track and report the corresponding numbers for the 2012-2013 period.

These O&M expenditures relating to NGV are part of FEI's natural gas business and are for the benefit of all natural gas customers. The administrative burden of tracking and reporting these actual amounts would be disproportionate to the amounts being incurred.

163.0 Reference: Compressed Natural Gas and Liquefied Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, pp. 14-15; TGI Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for CNG and Liquified Natural Gas Service (CNG& LNG Application), Part 5.1.2.3

CNG and LNG

TGI Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for CNG and Liquified Natural Gas Service (CNG& LNG Application)

Table 5-1: Useful Life and Resulting Depreciation Rates for CNG and LNG Fueling Assets

Asset	**Estimated Useful Life (years)**	**Depreciation Rate (%)**
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%
Capitalized Overhead69	Average	2.70%

163.1 Do the above depreciation rates for CNG and LNG fueling assets include a negative salvage provision? If not, what would those provisions be, including negative salvage rates proposed in this Application?

Response:

Please refer to the response to BCUC IR 1.140.2.

164.0 Reference: Thermal Energy

Exhibit B-1, Application, Appendix G, Part 2.4.1, p.4

Thermal Energy- Direct Costs

For all alternative energy programs conducted by the Utility and forecast in this RRA, including those approved by various past Commission Orders, provide a summary of program details in the table format shown below (Biomethane is used as an example):

Biomethane:

	2010 Actuals	2011 Projected	2012 Forecast	2013 Forecast
Program Revenues				
Program Cost recovered from All rate payers:				
description				
description				
subtotal				
Program Costs segregated for recovery from program users:				
Description				
Description				
subtotal				
Total Deferral Accounts at end of period:				
Deferral account description				
Deferral account description				

Response:

For clarification, the FEU interpret the use of the term "alternative energy programs" to mean the FEU's Thermal Energy Solutions initiative. Projects within this initiative will be submitted to the BCUC for approval according to the terms and conditions of the FEI 2010-2011 NSA.

Pursuant to BCUC Order No. G-141-09, all costs associated with Thermal Energy Solutions (referred to as Alternative Energy Services in the BCUC Order No. G-141-09) are captured in a separate deferral account for future recovery from Thermal Energy Solutions customers. That is, the balance in the Thermal Energy Deferral Account will not be recovered from gas utility customers. Please refer to the FEU's confidential response to BCUC IR 1.157.1 for a breakdown of Thermal Energy Solutions costs by project, resource and year. The recovery of costs in the Thermal Energy Deferral Account from thermal energy customers will be considered in FEI's future applications to the BCUC.

Details regarding FEI's NGV fueling service and biomethane initiatives are provided in the Application (Appendix B-1), Appendices I and J, respectively. These initiatives are natural gas services and are not alternative energy programs.

164.1 Provide your detailed account sub-ledgers used to track these costs within the general ledger.

Response:

The FEU use separate internal order or "IO" numbers to track the costs incurred for and allocated to specific thermal energy projects. These IOs settle at each month-end to one of two deferral accounts – either 18007 Alternative Energy Projects – O&M or 18008 Alternative Energy Projects – Capital.

The list of IO numbers is sequentially assigned and has little meaning, so we have not included the IO numbers themselves in this response. The costs associated with those IO's have been included in the FEU's confidential response to BCUC IR 1.157.1 by project name.

164.2 Describe how all employee time is tracked and allocated to each of the alternative energy projects. This should include how time is tracked and allocated for senior management and board functions.

Response:

When a Thermal Energy Services project is identified, the FEU create a new Internal Order ("IO") with a separate IO number. When an employee completes her or his time sheet at the end of each week, that employee identifies the IO for each thermal energy project that she or he worked on during that week together with the number of hours they worked on each project. That information is then entered into the FEU's SAP system where it is tracked on an ongoing basis. Senior management time and board functions are allocated in general to Thermal Energy Services through the shared services allocation process as agreed to in the approved NSA for the 2010-2011 RRA. The allocation of general thermal energy service costs to Thermal Energy Services customers will be determined as part of a future rate design application for Thermal Energy Services.

164.3 Complete the table below for the allocation management time allocations:

Name of Employee (for all FEU directors and above who have worked on alternative energy projects)	**Percentage of total time allocated to alternative energy project 1**	**Percentage of total time allocated to alternative energy project 2**	**Percentage of total time allocated to alternative energy project 3**	**Have salary/bonus/other benefits of this employee be allocated to alternative energy projects on a prorata basis consistent with the time spent on the project?**
Name 1				
Name 2				

Response:

The only Director level employee or above who charges time to specific thermal energy services projects is the Director of the Thermal Energy Services Group. As such a table is not required in response to this request.

The Director of Thermal Energy Services charges his time to each Thermal Energy Services Project as appropriate following the process described in response to BCUC IR 1.164.2, as well as to the thermal energy services deferral account in general for general business development activities as appropriate. As such, the direct project costs related to that Director's time are captured in the confidential response to BCUC IR 1.157.1. All other costs related to that Director's business development activities including salary/bonus and other benefits are reported in the sales and marketing costs line of the Thermal Energy Solutions deferral account shown in the Application (Exhibit B-1), Table G-2, page 4, Appendix G. The allocation of sales and marketing costs among thermal energy services customers will be determined as part of a future rate design application for thermal energy services.

164.4 What would be your views on separating all non-gas alternative energy services into a separate division?

Response:

The FEU interpret the term "all non-gas alternative energy services" to mean renewable Thermal Energy Solutions. We view our current approach to organizational structure and the processes and procedures for tracking and allocating costs to thermal energy solutions customers as appropriate.

FEI has created a separate division or group called Thermal Energy Solutions to manage the majority of activities associated with the development and delivery of Thermal Energy Solutions. Further, the FEU have implemented processes and procedures for tracking and allocating all costs associated with the development and delivery of thermal energy services in order that these costs are not allocated to natural gas customers in accordance with the Negotiated Settlement Agreement for the 2010-2011 RRA as approved by the Commission. These processes and procedures are explained in the Application (Exhibit B-1), Appendix G and in response to BCUC IRs 1.164.1, 1.164.2 and 1.164.3. Finally, we wish to note that the delivery of renewable thermal energy services is almost always integrated with the delivery of conventional gas and / or electricity services.

The current organizational structure and allocation processes and procedures have important benefits for natural gas customers. For example, as fuel switching opportunities arise for existing or potential natural gas customers and these customers seek to reduce their carbon foot print, the FEU can offer mixed energy solutions that help ensure natural gas remains part of the energy mix. This continued use of natural gas infrastructure provides for a robust, reliable and secure energy mix for the customer and Province as a whole, and helps to manage the impacts on conventional energy delivery systems that might be caused by widespread fuel switching activities.

164.5 Please explain how time allocations have impacted cost allocations of shared and corporate services?

Response:

The time and overhead allocations to Thermal Energy Services deferral lowers the overall costs pools which are allocated as shared and corporate services to the natural gas customers.

These lower costs pools result in a lower amount costs being allocated for both shared and corporate services.

164.6 Have the Companies performed a cost allocation study for alternative energy projects?

Response:

Pursuant to the NSA approved by Order No. G-141-09, page 9, costs and revenues received for all AES projects, based on contracts approved by Commission, are recorded in the AES (now called TES) deferral account.

Project specific costs will be recovered from the customers who elect to obtain thermal energy from FEI. These project-specific costs, along with a suitable level of overheads (discussed further below), will be included in the costs of service that will be filed to justify the rate within the contract signed by the customer.

It is also our intention to include in the TES deferral account TES project costs related to sales and marketing O&M, and overhead costs that have been incurred to-date and going forward. The methodology of how such costs will be allocated will be discussed in the first AES project to be filed in the coming months.

Given that the TES line of business is growing and evolving it is expected that in future a cost allocation study will need to be done. It is important to have enough actual cost data before a reliable comprehensive cost allocation study can be done for the TES class of service.

164.7 When will the Companies perform a cost allocation study for alternative energy projects?

Response:

Please see the response to BCUC IR 1.164.6.

165.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 1, p. 1

Revenues from NGV Initiatives

"The forecasts made in relation to NGV fueling infrastructure in the Application and in this Appendix are premised on the assumption that the NGV Application will be approved as filed and all approvals sought will be granted. The forecasts are further premised on the assumption that the EEC incentives for NGVs from the Innovative Technology Program Area will continue during the test period of this RRA."

165.1 To what extent do the forecast revenues from NGV initiatives as outlined in Appendix I depend on the assumption that EEC incentives are available for NGV initiatives?

Response:

In its forecast, FEI has assumed all future NGV customer additions would receive EEC incentive funding. These volume additions are directly linked to EEC incentive funding (please see pages 5-6 of Appendix I of Exhibit B-1).

FEI believes that EEC incentives for NGVs are necessary to 'kick-start' market transformation by offsetting the incremental capital cost barrier presently associated with NGVs. The lack of NGV adoption over the past few years has demonstrated this requirement, amongst other factors.

165.2 If EEC incentives are not available for NGV initiatives, please quantify the impact on the forecast revenue from transportation rate schedules.

Response:

FEI has provided a table showing the forecast revenue from transportation rate schedules if EEC incentives are not available for NGVs. Please refer to Table I-8 in Appendix I of Exhibit B-1 for the forecast revenues including EEC incentives.

	Transportation Delivery Margin Revenue (in thousands)		
Transportation Rate Schedule	**2011**	**2012**	**2013**
CNG			
Rate Schedule 6	$ 16	$ 16	$ 16
Rate Schedule 23	$ 4	$ 16	$ 16
Rate Schedule 25	$ 10	$ 14	$ 14
LNG			
Rate Schedule 16	$ 228	$ 548	$ 548
Total:	**$ 259**	**$ 595**	**$ 595**
Annual Incremental:	**$ 259**	**$ 336**	**$ -**

Note: Delivery Charges are Rate Schedule 6, $3.648, Rate Schedule 23, $2.318,
Rate Schedule 25, $0.645, and Rate Schedule 16, $3.96

The NGV projects currently underway (and funded with 2010/11 EEC incentives) will continue at their forecast volumes. However, without NGV incentives, no new customer additions are anticipated due to the capital cost barriers presently associated with new factory NGVs. The rate of market transformation impacts whether customers choose to adopt NGVs in the absence of incentive funding; however at this time, FEI does not believe fleet operators are prepared to do so.

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.

FEI's NGV initiatives have many benefits to customers, including mitigating upward pressure on natural gas delivery rates resulting from decreases in system throughput. In the absence of the revenues generated from NGV initiatives, customers would be faced with rates higher than applied for in this Application, all else equal.

165.3 If EEC incentives are not available for NGV initiatives, please quantify the impact on the forecast revenue from fueling service contracts.

Response:

In the table below, FEI has provided a table showing the forecast revenue from fueling service contracts if EEC incentives are not available for NGVs. Please refer to Table I-10 in Appendix I of Exhibit B-1 for the forecast revenues including EEC incentives.

	Fueling Service Contract Revenue (in thousands)		
Vehicle Class	**2011**	**2012**	**2013**
CNG			
Light Duty Vehicles	$ 25	$ 25	$ 25
Buses	$ 14	$ 54	$ 54
Garbage Trucks	$ 87	$ 113	$ 113
Total:	$ 126	$ 191	$ 191
LNG			
Class 8 Tractors	$ 216	$ 519	$ 519
Total NGV Revenue:	**$ 341**	**$ 710**	**$ 710**
Annual Incremental:	**$ 341**	**$ 369**	**$ -**

The forecast revenues in 2011 are expected to remain the same because the 2010/11 EEC incentives are embedded in existing rate base. In the absence of EEC incentives for NGVs in 2012 and 2013, revenues would decrease by $1.4 million ($2.1 million with EEC - $0.7 million without EEC) in 2012 and $2.4 million ($3.1 million with EEC -$0.7 million without EEC) in 2013.

The fueling service contracts, as proposed in FEI's CNG and LNG Service Application (filed December 1, 2010 with the Commission), are structured to recover infrastructure costs through contractual 'take-or-pay' agreements, with a fueling station rate set to recover the forecast cost of service incurred in the contract term. Thus, the revenues generated from fueling service contracts generally equal the costs.

Please refer to BCUC IR 1.165.2 for further discussion on market transformation.

165.4 Assuming EEC incentives for NGVs continue, would choosing to build their own fueling station make an NGV customer ineligible for EEC incentives?

Response:

An NGV customer is eligible for EEC incentives if they choose to build their own fueling station. The provision of EEC incentives is not dependent on the customer's decision with respect to building, owning and maintaining a fueling station independently or to contract with FEI or a third-party. In fact, the first EEC incentive payment in the NGV program was provided in 2010 to the City of Surrey which maintains its own fueling station. Please refer to BCUC IR 1.199.2 for further discussion regarding the eligibility criteria for EEC NGV incentives.

166.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 2.2.2, pp. 9-10

Station Capital and Annual O&M

"The annual Transmission O&M for FEI's NGV fueling projects in Table I-8 show annual requirements of approximately $133 thousand in 2012 and an incremental $106 thousand in 2013. These costs are for increased electricity costs at the Tilbury LNG Facility."

166.1 Are these increased electricity costs at the Tilbury facility due entirely to customers taking service under Rate Schedule 16?

Response:

Yes, these forecast increased electricity costs are due entirely to customers taking service under Rate Schedule 16. This forecast is reflective of the Rate Schedule 16 volume forecast in Table I-3 in Appendix I of Exhibit B-1.

166.2 To what extent are these incremental electricity costs recovered through the O&M component of the Rate Schedule 16 rate?

Response:

While there is no direct linkage to the cost of electricity, the O&M component of the Rate Schedule 16 variable charge does allow for the recovery of electricity costs as well as other O&M costs such as labour, materials and outside services. Electricity costs were included in deriving the O&M component of Rate 16, comprising approximately 35% of the total O&M.

In accordance with BCUC Order No. G-65-09, the O&M component of the Rate Schedule 16 variable charge is adjusted on an annual basis by BC CPI. Therefore, to the extent that incremental costs are higher than inflation, the incremental O&M costs higher than inflation will be recovered from all non-bypass customers.

FEI will seek Commission Approval for the annual changes to the rate components of Rate Schedule 16 in December (preceding the effective date of January 1) or in January once the variable charge components requiring update are known.

166.3 If these incremental costs are not recovered through the Rate Schedule 16 rate, please explain whether or not they should be.

Response:

Please refer to BCUC IR 1.166.2 and BCUC IR 1.112.1. The various rate components of Rate Schedule 16 are updated on an annual basis in accordance with Commission Order No. G-65-09. While FEI does not intend to address issues pertaining to cost allocation or rate design in this Revenue Requirements Application, as discussed in BCUC IR 1.171.2, FEI agrees that all incremental costs attributable to providing LNG for NGV must be considered in the determination of the variable charges for Rate Schedule 16.

167.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 3, pp. 10-13

Revenues from NGV Initiatives

167.1 Is the LNG fueling service contingent on FEI providing the transportation of the LNG from the Tilbury facility to the fueling station?

Response:

This response also addresses BCUC IR 1.167.2 and BCUC IR 1.167.3.

To receive tanker truck quantities of LNG from our Tilbury facility to their refueling site, each NGV customer will have the option to select LNG delivery service or provide their own transportation and delivery.

FEI anticipates it will provide LNG tanker truck service to transport LNG if requested by customers. FEI's first LNG customer, Vedder Transport, has contracted with FEI to provide such LNG delivery service.

FEI currently owns and operates two LNG tankers. As its usual practice, FEI will subcontract the tractor portion of the delivery service to a third party. While safe and reliable handling of LNG is inside FEI's areas of competency, operation of a tractor unit is a service that a third party operator can presently offer more economically than FEI.

167.2 Does FEI anticipate that it will provide an LNG tanker truck service to transport LNG from the Tilbury facility to the LNG fueling stations?

Response:

Please refer to BCUC IR 1.167.1.

167.3 If so, will FEI own the tankers, lease the tankers, or contract for this service from others?

Response:

Please refer to BCUC IR 1.167.1.

167.4 What rate will FEI charge for transporting LNG from Tilbury to the LNG fueling stations?

Response:

FEI will determine, and seek Commission Approval for, the rate for transporting LNG from Tilbury to the LNG fueling stations in conjunction with its forthcoming submission for approval of a Temporary Refueling Agreement with Vedder Transport. FEI intends to propose a rate for LNG delivery service that recovers not only the incremental costs of service but also one that uses .a cost of service-based rate to recover revenues that will provide an incremental benefit to customers by gaining extra utilization from existing utility assets.

In the event that demand for use of FEI's tankers grows beyond the point where such scheduling can be accommodated, FEI will evaluate the possibility of purchasing additional tankers.

167.5 Are the revenues and costs associated with this service included in the Application? If so, where?

Response:

The revenues associated with the transportation of LNG from Tilbury to the LNG fueling station are not included in this Application. At the time of this Application's filing, FEI has not fully developed a proposed LNG tanker service charge. FEI expects to submit a proposed service charge (along with a Temporary Refueling Agreement with Vedder Transport) for Commission Approval in the near future.

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.

168.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 3.2, p.11

Revenues from NGV Initiatives

Table I-9 provides contract rates for fueling service for various types of customers.

168.1 What assumptions were made for each of the rates listed in the table specifically with regard to

- contract term,
- buy-out clauses and/or other mechanisms to reduce exposure to un-depreciated capital/stranded assets,
- O&M escalation rates, and
- depreciation rates.

Response:

The contract rates presented in Table I-9 of the Application (Exhibit B-1) are based on preliminary cost of services estimates for FEI's current and potential CNG and LNG customers. NGV customers have varying fueling station requirements. The rates FEI has been developing for potential customer applications range from approximately $2/GJ to over $10/GJ. The wide range in rates reflects very different situations regarding the type of fueling infrastructure that is needed and the wide range in gas consumption. Thus, it is difficult to develop assumptions related to the contract term and buyout clauses without fully assessing each customer's requirements and entering into negotiations.

However, throughout FEI's Application for CNG and LNG Service proceeding (presently before the Commission at the time of this filing), FEI has stated the following on the items listed within the question:

Contract term

From Exhibit B-6 of the CNG and LNG Service Application, response to BCUC IR 2.3.1:

> *"...TGI expects the initial term of future contract will vary. TGI will, in general, attempt to maximize the term of the agreement to minimize the risk of stranded assets at the completion of the initial term. For most customers, we expect that the initial term of the contract will be matched with the expected lifetime of the NGVs that are being purchased for that facility. In most cases Terasen Gas anticipates this will be 5 to 10 years."*

Buy-out clauses, etc.

From Exhibit B-11 of the CNG and LNG Service Application, response to BCUC IR 3.14.2:

> *"FEI is, where possible in the negotiation, attempting to obtain buy out provisions that require a payment from the customer to cover remaining capital on the assets if the fueling agreement is not renewed."*

O&M escalation rates

From Exhibit B-11 of the CNG and LNG Service Application, response to BCUC IR 3.12.1:

> *"For each project, FEI will determine an estimate of the annual O&M budget based on the equipment that is installed. This is then escalated to reflect inflation in O&M costs at a rate of 2% per year and this is factored into the calculation of the COS."*

Depreciation rates

From Exhibit B-6 of the CNG and LNG Service Application, response to BCUC IR 2.4.1:

> *"The following table provides a summary of the inputs into the cost of service model:*

Input Item	Parameter
In-service Date (ddmmyyyy)	
Minimum contract demand (GJ/year)	
Incremental O&M ($000's, per year)	
Capital Spending ($000s, per year)	
CNG/LNG Dispensing & Storage Equipment	
Foundation	
Pumps	
NG Dehydrator	
Contributions in Aid of Construction	
Capitalized Overhead Rate	14%
O&M Inflation Rate	2%
Contract Term (yrs)	
Contract Rate Inflation (%)	
Depreciation Rates	
CNG/LNG Dispensing & Storage Equipment	5.0%
Foundation	5.0%
Pumps	10.0%

Input Item	Parameter	
NG Dehydrator	5.0%	
Capitalized Overhead	2.7%	
CCA Class		
CNG/LNG Dispensing & Storage Equipment	8	
Foundation	1.3	
Pumps	8	
NG Dehydrator	8	
Capitalized Overhead	51	
CCA Rate		
CNG/LNG Dispensing & Storage Equipment	20.0%	
Foundation	6.0%	
Pumps	20.0%	
NG Dehydrator	20.0%	
Capitalized Overhead	6.0%	
Income Tax Rate	25.0%	*
Property Tax Rate (Foundations)	3.91%	
Property Tax in Lieu of Rate	1%	
Return on Rate Base	7.93%	
AFUDC Rates & After Tax WACC	6.90%	**

*The income tax rate is 26.5% for 2011 only

**The AFUDC rate is 6.83% for 2011 only

Update of Inputs for the Cost of Service Model

From Exhibit B-6 of the CNG and LNG Service Application, response to BCUC IR 2.4.1.1:

> *"... the inputs into the cost of service model are reviewed and updated each time that the model is used to evaluate an agreement and determine a contract rate."*

169.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, Section 3, pp. 10-13

Revenues from Rate Schedule 16

169.1 Please confirm that Rate Schedule 16 is available to customers that are not NGV customers.

Response:

Confirmed. FEI interprets the wording of Rate Schedule 16 as determining the rate for sale and dispensing of LNG out of the Tilbury facility without prejudice as to its intended end use.

169.2 Do the revenues and volumes outlined in Appendix I include any forecast revenues and volumes from Rate Schedule 16 sales to customers who are not NGV customers?

Response:

No, the revenue and volume forecasts in Appendix I only consider NGV customers at this time.

169.3 Does the Application include any forecast revenues and volumes from Rate Schedule 16 sales customers who are not NGV customers?

Response:

Please refer to BCUC IR 1.169.2.

169.4 Has FEI had any inquiries or discussions with potential Rate Schedule 16 customers who would not be using LNG for NGV purposes?

<u>Response:</u>

Yes, 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 vaporized LNG to displace propane in existing distribution grids.

170.0 Reference : Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, p. 6

Rate Schedule 16 Status

"Rate Schedule 16 presently has status as a pilot program which expires on December 31, 2014."

"A 1,040 GJ per day supply limitation also exists under Rate Schedule 16. If FEI contracts 1,040 GJ for 365 days, a volume of 379,600 GJ per year would be reached. Based on Table I-3 above, FEI's fuel demand estimate would surpass the 379,600 GJ level at the end of 2012, necessitating supply beyond the 1,040 GJ per day limitation."

170.1 Given the limitations of Rate Schedule 16 and the forecast volumes for Rate Schedule 16, is it likely that incremental investment in facilities may be required at the Tilbury facility during the 2012-2013 revenue requirements period?

Response:

Please refer to BCUC IR 1.112.3.2.

170.2 To what extent has the status of Rate Schedule 16, as a pilot program with limitations on the quantity and a fixed expiry date, been a barrier or concern to potential LNG NGV customers?

Response:

Through the course of negotiations, potential LNG NGV customers have been informed of, and are aware of the status of Rate Schedule 16 as a pilot program and quantity limitations. Despite these risks, our first potential LNG customer, Vedder Transport, has made a significant long-term investment in purchasing LNG vehicles for their trucking fleet. Based on this investment, it appears that Vedder Transport has an expectation that Rate Schedule 16 will continue beyond its pilot period, enabling Vedder to fuel their vehicles with LNG, reduce fueling costs, and generate environmental benefits. While the estimated fuel consumption for Vedder's initial fleet of 50 LNG vehicles does not present a quantity constraint at this time, further LNG fleet expansion may be constrained by this limitation in the future. Thus, FEI anticipates making an application later this year to deal with the future of Rate Schedule 16 and its expansion.

170.3 Given that Rate Schedule 16 is a pilot program, it is reasonable to expect that the permanent rate for Rate Schedule 16 could be modified to reflect the findings of the pilot program?

Response:

Yes, FEI agrees that is reasonable to expect that the findings from a pilot program would be incorporated in a permanent program. FEI plans to submit an application related to amending Rate Schedule 16 later this year, in which we will address what we have learned from the pilot program and present proposals for the continuation of Rate Schedule 16.

171.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Appendix I, Application, pp. 12-13

Rate Schedule 16 Revenues & Associated O&M

"Production of LNG at Tilbury will generate incremental O&M cost associated with increased production of LNG at Tilbury and this cost will partially offset the revenue benefit referred to above. As discussed in the May 7, 2009 Rate Schedule 16 application, this incremental cost is estimated at $1.95/GJ or 52% of the rate. The remaining balance represents contributions that are incremental to existing O&M and capital accounts; thus they provide benefits to all ratepayers."

"The case for incremental investment in LNG storage would be justified by the benefits provided by such investment and these benefits may not be restricted just to Rate Schedule 16 customers."

171.1 If the benefits of incremental investment in LNG storage at Tilbury were restricted to Rate Schedule 16 customers, would the test for proceeding with the incremental investment be the equivalent of a Mains Extension test given that the expansion may be sized to meet demand that had not yet been contracted for?

Response:

Any potential proposal for an expansion of the capital invested at the Tilbury LNG facility would need to consider the forecast incremental costs and the forecast incremental revenues associated with such an expansion. In this manner, such a consideration would bear some similarity to the Mains Extension test. FEI is neither proposing, nor speculating on, the costs and revenues associated with incremental investment in LNG storage at Tilbury in this Application. It is important to highlight that such incremental investments, which would be caused by and result in greater throughput on our delivery system, would likely benefit all customers.

171.2 In the event that incremental investment in LNG storage at Tilbury was determined to benefit only Rate Schedule 16 customers, is it reasonable to expect that the incremental O&M cost component of the resulting Rate Schedule 16 rate may be somewhat higher than 52% of the rate?

Response:

FEI has not proposed an investment in LNG storage at Tilbury in this Application. FEI does not believe that it is appropriate to speculate on potentially forthcoming rate design proposals for Rate Schedule 16; however, FEI commits to ensuring that any future rate design of Rate Schedule 16 will continue to reflect appropriate cost allocation. FEI agrees that incremental O&M is an important consideration that may impact the variable components of the rate structure, but FEI is unable to say at this point whether this would be higher or lower than 52 percent of the rate.

Please also refer to BCUC 1.171.1.

172.0 Reference: Compressed Natural Gas and Liquified Natural Gas Fueling Report

Exhibit B-1, Application, Appendix I, p. 6

Revenue from NGV Initiatives

172.1 What was the first day of service for the Waste Management service?

Response:

The Waste Management ("WM") facility was in service February 25, 2011; that is, the fueling station achieved final commissioning and was in use by WM's fleet on February 25, 2011. WM was billed for their first month of 'take-or-pay' service beginning on March 1, 2011 using the rate as approved on an interim basis through Commission Order No. G-06-11.

Additional significant dates with respect to the WM facility are as follows:

- Meter installation at the WM refuelling facility took place the week of January 31, 2011, with natural gas flowing shortly thereafter;
- Pre-commissioning (i.e. pressure testing, input/output checks, final inspections) of the WM facility occurred during the week of February 14, 2011;
- Final commissioning (i.e. equipment start-up, testing, and operator safety training) of the WM facility occurred the week of February 21, 2011.

173.0 Reference: Exhibit B-1, Application, Appendix J, Table J-1, p. 6

Exhibit B-1, Application, Tab 7.5, Schedule 21

Biomethane – Gas Plant in Service balance at the end of 2011

173.1 Please reconcile the accumulated capital expenditures projected to the end of December, 2011, shown in Table J-1 ($3,204.3 thousand), with the Bio Gas Plant in Service balance on December 31, 2011 shown on Schedule 21 ($3,917). How much, if any, of the difference is attributable to capitalized overhead additions?

Response:

FEI interprets the intent of the question was to reference Schedule 44 of Tab 7.5 (Exhibit B-1-2), rather than Schedule 21 of Tab 7.5 which reflects the resource view of O&M.

Please refer to the table below which reconciles the Biomethane 2011 plant addition of $3.917 million reflected on Line 53 of Schedule 44 of Tab 7.1 with the capital spending of $3.204 million reflected in Table J-1 of Appendix J:

Reconciliation of Biomethane Gas Plant In Service Additions
($ Thousands)

Table J-1 (Capital Spending)	$	3,204
Add: AFUDC		123
Add: Allocated Capitalized Overhead		590
Plant Additions (Line 53, Column 4, Schedule 44, Tab 7.1)	$	3,917

As per FEI's policy, the capitalized overheads are allocated to all plant additions except for CPCN projects, meters, and general plant. The amount of the overhead capitalized is based on 14 percent of the gross operating and maintenance expense for the year.

174.0 Reference: Exhibit B-1, Application, Appendix J, pp. 3-4 and Table J-4, p. 10

Biomethane - Projection of volumes over the forecast period

In G-194-10, the Commission stated: *"Therefore, we have provided in our determination that TGI can purchase a total of 250,000 GJ annually which will allow some latitude for TGI to proceed with some additional projects before returning to the Commission with the results from what has been undertaken and recommendations for the future. Nevertheless, the Panel would like to be clear that in spite of this, we view these initial programs as a test phase only. The results from these projects will very much determine whether the Program will continue and whether the model as proposed is suitable." (G-194-10, p. 42).*

Commission Staff wish to understand the impact of the future biomethane projects (Appendix J, p. 4) on the volume of purchases of biomethane that FEU will be obligated to make.

174.1 Please complete the following table setting out the volumes, in gigajoules, of biomethane that FEU forecasts to purchase from existing and future projects. Please include the volumes that FEU is obligated to purchase.

Project	2011	2012	2013	2014	2015
Catalyst (contractual obligation)					
CSRD (contractual obligation)					
City of Kelowna					
Annacis Island					
Other					
Total					

Response:

In compliance with the directive in Commission Order No. G-194-10, FEI will not purchase biomethane in excess of the maximum annual supply of 250,000 GJ without Commission approval of expansion of the biomethane program. Order No. G-194-10 approved a 2 year trial period for the biomethane program which expires in December 2012, approximately mid-way through the RRA period (2012-2013). FEI's forecast volume of biomethane supply in the Application (Exhibit B-1), Appendix J, Table J-4, is based on existing contracts and future contracts subject to Commission approval.

FEI believes that the market for biomethane will continue to grow and is therefore continuing to evaluate new biomethane projects as contemplated in Order No. G-194-10 (e.g. at page 56).

Since the contracted maximum volumes for the approved Catalyst and CSRD projects combine for a total of 220,000 GJ per year, the remaining volume within the Commission's cap on annual supply is 30,000 GJ per year. To date, FEI has not found a project that could be economic with a long-term annual contract maximum amount of 30,000 GJ or less. Any future biomethane contracts will be subject to Commission approval. In FEI's view, factors that will contribute to determining whether a contract would be approved to raise the 250,000 GJ cap would include take up rates by customers on the supply that is being produced from existing projects, and what is the current and expect production rates from the existing project given some operational experience and data

The following are the minimum expected and maximum volumes of the current biomethane contracts held and potential future contracts. The obligated amount of supply will be the amount of supply that a given producer can provide up to the contract maximum.

Contract Minimums

Table 1 - Contract Minimums

Project	**2011**	**2012**	**2013**	**2014**	**2015**
Existing					
Catalyst [1]	25,000	84,000	84,000	84,000	84,000
CSRD[2]	0	20,000	20,000	20,000	20,000
FUTURE					
City of Kelowna	-	-	-	-	-
Annacis Island	-	-	-	-	-
Other	-	-	-	-	-
Total	**25,000**	**104,000**	**104,000**	**104,000**	**104,000**

As details of future contracts have not yet been negotiated, no minimum amount can be given for future contracts at this time.

Note 1: The contract for Catalyst Power Inc. ("Catalyst") is written such that the minimum contract volume has still not been triggered. It is likely that this minimum number will be reached in 2011. Therefore, FEI currently has no minimum future purchase obligation. However, FEI has purchased all of the biomethane produced to date (total of approximately 25,000 GJ). Once the minimum supply volume is triggered, FEI will be obligated to purchase 84,000 GJ/year of the biomethane produced.

Note 2: The CSRD contract is written such that there are no contractual obligations arising until FEI first delivers biomethane (via the upgrading plant). The contractual obligations are expected to be triggered in late 2011 following the commissioning of the plant. At that point, the expected minimum annual volume will be 20,000 GJ/year.

Expected Volumes

Table 2 below represents the amount of biomethane that FEI is expecting to purchase. As mentioned above, FEI would be obligated to purchase all of the expected volumes, if produced pursuant to a signed and Commission-approved contract. The amount of expected supply of biomethane is based on a combination of actual delivery from the Catalyst project and likely production volumes based on the experience to date with the Catalyst project and the CSRD ("Salmon Arm") project. As shown in Appendix J (Table J-4), the expected supply is broken down below.

Table 2 - Expected Volumes

Project	2011	2012	2013	2014	2015
Existing					
Catalyst [3]	61,000	109,500	109,500	109,500	109,500
CSRD[4]	2,000	26,000	26,000	26,000	26,000
SUBTOTAL	**61,000**	**135,500**	**135,000**	**135,500**	**135,500**
FUTURE					
City of Kelowna		50,000	50,000	50,000	50,000
Annacis Island		20,000	100,000	100,000	100,000
Other		30,000	150,000	150,000	150,000
SUBTOTAL	0	100,000	300,000	300,000	300,000
Adjusted Volume[5]	**0**	**50,000**	**150,000**	**150,000**	**150,000**
Total (Contracts + Expected)	**61,000**	**185,500**	**285,500**	**285,500**	**285,500**

Note 3: Currently, the amount delivered is lower than originally anticipated in estimates provided by Catalyst. Catalyst is in the process of determining an updated expected gas production estimate which will be used by FEI for planning purposes. At this time, Catalyst has indicated that the expected daily flow will be lower than originally expected for the next few years. This is a result of lower than expected raw biogas production and limitations on the current digester facility. The expected production increase over 2011 to approximately 109,500 GJ per year for the next several years based on the current installed biogas plant.

Note 4: The Salmon Arm landfill projections are based on current raw gas flow and timing of upgrade plant installation.

Note 5: FEI has elected to treat the volume of future supply differently than the supply estimates provided for existing projects. FEI believes that it is reasonable to assume a 50% success rate for future projects based on experience to date with regard to technical and economic evaluation of proposed projects. The expected volume has therefore been weighted at 50% for the prospects to give a more realistic volume estimate. FEI has used similar methodology to estimate future capital expenditures for biogas projects. Each potential project has an estimated capital cost, and FEI has applied a likelihood of success to arrive at projected capital costs for 2012-2013.

Contract Maximums

Contract maximums have been determined based on either the ability of the FEI system to accept biomethane (based on summer loads) or limitations of the supply, such as projected biomethane production based on the amount of waste in place at the landfill. The contract maximums also take into account the long-term nature of the contracts and therefore assume some growth in both capacity of projects and demand by customers. Accordingly, the maximum volumes should not be realistically expected, especially in the early years of any contract.

The contract maximums are provided in Table 3 below.

Table 3 - Contract Maximums - Existing

Project	**2011**	**2012**	**2013**	**2014**	**2015**
Catalyst	0	180,000	180,000	180,000	180,000
CSRD	0	40,000	40,000	40,000	40,000
Total		**220,000**	**220,000**	**220,000**	**220,000**

At this time, because FEI does not have any contracts finalized for future supply projects, contracts maximum cannot be provided. However, analysis has been done on the capacity of the system for each of these projects, so these could be considered as plausible contract maximums. As noted above, contract maximums are not a good indicator of the actual projected supply.

Table 4 - Contract Maximums - Possible

Prospects	2011	2012	2013	2014	2015
City of Kelowna		N/A	170,000	170,000	170,000
Annacis Island			200,000	200,000	200,000
Other			50,000	50,000	50,000
Subtotal			420,000	420,000	420,000
Adjusted Volume	0	0	210,000	210,000	210,000
POSSIBLE Total MAX	0	220,000	430,000	430,000	430,000

The future forecast supply includes speculation on future projects which are currently in the evaluation and negotiation stages. The nature of the project development is a long-term cycle, and therefore, prospects may appear well-ahead of a firm contract. Although there are multiple potential projects, FEI does not expect to successfully develop all of these projects. A 50 percent success rate is expected.

Summary of Supply

For convenience, FEI has incorporated the total minimum, expected and maximum volumes in one table

Table 5 - Summary of Projected Volume

Project	2011	2012	2013	2014	2015
Min	25,000	104,000	104,000	104,000	104,000
Expected	30,000	125,500	203,000	233,000	248,000
Max	0	220,000	430,000	430,000	430,000

174.2 Please complete the following table setting out the volumes, in gigajoules, of biomethane that FEU forecasts to purchase from existing and future projects. Please include the volumes that FEU is expected to purchase.

Project	2011	2012	2013	2014	2015
Catalyst (contractual obligation)					
CSRD (contractual obligation)					
City of Kelowna					
Annacis Island					
Other					
Total					

Response:

Please refer to the response to BCUC IR 1.174.1.

174.3 Please complete the following table setting out the volumes, in gigajoules, of biomethane that FEU forecasts to purchase from existing and future projects. Please include the maximum volumes, specified in the contracts, that FEU can accept.

Project	2011	2012	2013	2014	2015
Catalyst (maximum)					
CSRD (maximum)					
City of Kelowna					
Annacis Island					
Other					
Total					

Response:

Please refer to the response to BCUC IR 1.174.1.

174.4 Table J-4 forecasts biomethane purchases of 284,500 GJ in 2013. Please reconcile this forecast with the directive in Order G-194-10 limiting FEI to purchasing a maximum of 250,000 GJ annually.

<u>Response:</u>

Please refer to the response to BCUC IR 1.174.1.

175.0 Reference: Exhibit B-1, Application, Appendix J, p. 4 and Table J-1, p. 6

Biomethane - Projection of capital expenditures over the forecast period

On page 4 FEU states that a change in the design of the upgrading plant became necessary as a result of the "more thorough gas sampling of the raw landfill gas" that showed a difference between the actual and the expected raw gas composition. The design change increases the cost of the upgrading plant by approximately $300 thousand as compared to the original approved amount. In Table J-1, FEU has forecast capital costs for 2012 and 2013 related to a purification upgrader.

175.1 Has FEU carried out a sufficiently thorough sampling of the raw gas from each of the future projects for which the capital costs for 2012 and 2013 have been estimated?

Response:

The circumstances at the Salmon Arm landfill were unique due to the timing of the project. At the time the FEU originally negotiated the contract, testing was done to establish gas composition at the landfill. The original data was gathered prior to CSRD installing a landfill cap system so it was known that the initial testing was indicative but not be fully representative of final gas composition. The installation of a cap system allows for more accurate gas composition measurement. These circumstances are not likely to be repeated, but in future cases, the FEU will incorporate this lesson. In the case of Kelowna, for example, there is an existing cap and collection system in place, which has allowed for more accurate gas analysis.

Gas composition at other potential projects, such as at Annacis Island, will be evaluated ahead of the design process.

175.2 If the answer to the previous question is "no" then please explain why a thorough sampling of the raw gas has not been completed prior to completing an estimate of the capital costs associated with the biomethane gas upgrader.

Response:

Please see BCUC IR 1.175.1.

175.3 What is the length of mains that are forecast to be constructed in each of 2012 and 2013 to connect the future projects to FEU's distribution system?

Response:

The FEU will evaluate project economics according to the criteria outlined in the Biomethane application as stated in page 74 under assessment of future projects, section 8.4, including the cost of associated mains on a project-by-project basis. At this time we do not have certainty regarding the location of the forecast projects. However, for the projects we are currently evaluating, the average length of main is less than 1 km per project.

175.4 Does FEU expect to receive any further funding from the Innovative Clean Energy fund, the BC Bioenergy Network, or any other grants, for its future projects?

Response:

It is unlikely that the FEU will receive further funding from either the Innovative Clean Energy ("ICE") Fund or the BC Bioenergy Network.

In the case of the ICE Fund award and the BC Bioenergy Network, the grant awards are one-time awards for projects which are "first in category". Therefore, it is unlikely that future projects would qualify. However, the FEU is committed to minimizing project costs in order to keep biomethane rates and general customer rates as low as possible; so, if there is opportunity for grant funding, the FEU will consider applying in the future.

The FEU have not applied for any additional funding for any biomethane-related projects at this time.

176.0 Reference: Exhibit B-1, Application, Appendix J, Tables J-1, J-2, J-5, pp. 6,8,10

Biomethane - Projection of the future projects' impact on the revenue requirement

Commission Staff wish to understand the cumulative impact of the current and future biomethane projects to FEU's revenue requirement for 2012 and 2013.

176.1 Please complete the following table:

		2012	2013
Amortization of the O&M Deferral balance existing on Dec. 31, 2011 (Table J-5)		$205.3	$205.3
Amortization of the Other Revenue Deferral existing on Dec. 31, 2011 (Table J-5)		$30.0	$30.0
Forecast O&M, including the tax offset, related to the Catalyst and CSRD projects			
Forecast Other Revenues (Depreciation, Income Tax, and Earned Return) related to the Catalyst and CSRD projects			
Forecast O&M, including the tax offset, related to future projects			
Forecast Other Revenues (Depreciation, Income Tax, and Earned Return) related to future projects			
Total Revenue Requirement Related to biomethane projects recoverable from all customers	(in $000)		
	(in $/GJ)		

Response:

The total incremental revenue requirement impact of the current and forecast Biomethane projects is approximately $1.3 million in 2012 and approximately $1.5 million in 2013. These costs include the amortization of the non-program costs incurred in 2010 and 2011. The approximate annual bill impact to a Lower Mainland residential customer using approximately 95 GJs per year is $0.76 in 2012 and $0.86 in 2013.

Please see the updated table below followed by a discussion of the specific amounts:

		2012	2013
Amortization of the O&M Deferral balance existing on Dec. 31, 2011 (Table J-5)		$ 205	$ 205
Amortization of the Other Revenue Deferral existing on Dec. 31, 2011 (Table J-5)		30	30
Amortization of Biomethane Service Application Costs		64	64
Forecast O&M net of Overheads Capitalized at 14% related to Biomethane non-project costs		382	381
Forecast Depreciation, Income Tax, Earned Return for non-project costs		148	125
Forecast O&M net of Overheads Capitalized at 14% related to Catalyst - CSRD projects		17	17
Forecast Depreciation, Income Tax, Earned Return for Catalyst - CSRD project		312	302
Forecast O&M net of Overheads Capitalized at 14% related to Future Projects		3	60
Forecast Depreciation, Income Tax, Earned Return for Future Projects		96	286
Total Revenue Requirement Related to biomethane projects recoverable from all customers	in ($000's)	$ 1,258	$ 1,470
	in ($ / GJ)	$ 0.008	$ 0.009

Not all of the biomethane operating and maintenance costs are related to projects such as Catalyst and the CSRD, and these common program costs have been separated out into an additional two rows in the table above. The total incremental revenue requirement impact is divided by the total non-bypass Sales and Transportation volumes (Section 7.1, Schedules 8 and 9, Line 30) to determine an approximate impact per GJ.

177.0 Reference: Decision accompanying Order G-194-10, p. 52;

Exhibit B-1, Application, Appendix J, Tables J-2, J-5, pp. 8, 10

Biomethane - Recovery of 2010 and 2011 O&M costs related to customer education

In its Decision accompanying Order G-194-10, the Commission states that: *"The Commission Panel notes that TGI has budgeted $160,000, $240,000 and $300,000 for customer education in 2010, 2011, and 2012 respectively, but has not sought approval of these. The Commission accepts that these expenditures will be recorded in the appropriate deferral account. However, the Panel notes that recovery in future of these amounts will be subject to review by the Commission."*

177.1 Does FEU believe that the 2012/2013 revenue requirements proceeding is the appropriate mechanism through which to review the costs incurred by FEU related to customer education?

Response:

Yes, as per Commission directive, the 2012/2013 RRA proceeding is an appropriate mechanism to review all Biomethane costs, including customer education costs. Commission Order No. G-194-10 directed FEI to report on all Biomethane O&M and capital costs in its next RRA (as stated on page 58 of the Decision):

> *"Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA).* ***Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.*** *This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided".*

Furthermore, with respect to customer education:

> *"'The Commission Panel notes that TGI has budgeted $160,000, $240,000 and $300,000 for customer education in 2010, 2011 and 2012 respectively, but has not sought approval of these. The Commission accepts that these expenditures will be recorded in the appropriate deferral account. However, the Panel notes that recovery in future rates of these amounts will be subject to future review by Commission".*

As 2011 customer education costs are recorded in the deferral account and reflect a breakdown of the O&M costs for all customers, it should be reviewed within this Application.

177.2 In view of the fact that FEU has, up until the end of the first quarter of 2011, not incurred any significant costs related to customer education, is it premature to determine whether costs incurred to the end of 2011 should be recovered as part of the amortization of the biomethane O&M deferral account?

Response:

The Biomethane Application proposed to allocate and recover the costs of making the program available to customers, such as program administration and customer education, to all non-bypass customers, and that the costs for 2010 and 2011 would be collected into a biomethane O&M deferral account and the recovery of these costs in 2012 would be included in delivery rates. The proposed treatment was approved per BCUC Order No. G-194-10 (the "Biomethane Decision").

As indicated in Appendix-J of Exhibit B-1, Biomethane Report, FEI has planned for a mid-June launch of the program to residential customers. In order to prepare for this launch, as of June 9, 2011, $380,000 of the budgeted $400,000 has been allocated to customer education costs to the end of the year for the education and promotion of the Biomethane Service Offering. Of the $400,000 budget, $50,000 is being held back for additional customer education efforts in the fall, depending on customer uptake, and a small amount for contingency. Therefore, final expenditures to the end of 2011 for customer education will be between $330,000 and $400,000.

177.3 In view of the fact that FEU has, up until the end of the first quarter of 2011, not incurred any significant costs related to customer education, is it premature to determine whether costs forecast for 2012 and 2013 should be approved as part of the revenue requirement?

Response:

As discussed in BCUC IR 1.177.2 as of June 9, 2011, $380,000 has now been allocated to customer education costs of the budgeted amount of $400,000 for the period of 2010 to the end of 2011 for rollout of the Biomethane Service Offering. FEI expects customer education to be an ongoing activity until the program reaches the level of maturity required for customer groups to make informed decisions on whether or not they wish to participate in the program. FEI expects there to be additional biomethane supply available in 2012 and 2013 as discussed in BCUC IR 1.174.1, which would require continued customer education efforts to encourage sign ups. The budgeted amounts for 2012 and 2013 are a modest forecast in order to maintain and educate new customer groups on the program and the recovery mechanism was approved as a part of the Biomethane Decision, therefore, it is appropriate for these forecasted costs to be approved as part of the revenue requirement application for rate setting as part of a continued education plan.

177.4 Should the recovery of costs related to customer education be subject to the outcome of the review of the biomethane program at the end of 2012?

Response:

No. As discussed in BCUC IR 1.177.2, the Biomethane Application proposed to allocate and recover the costs of making the program available to customers, such as program administration and customer education, to all non-bypass customers, and that the costs for 2010 and 2011 would be collected into a biomethane O&M deferral account and the recovery of these costs in 2012 would be included in delivery rates. The proposed treatment was approved per BCUC Order No. G-194-10 (the "Biomethane Decision").

FEI will file a Biomethane Report in December 2012, in compliance with Order No. G-194-10, to review the two-year pilot program. Although this review will be commencing part way through the two-year test period for this RRA, FEI is of the view that it is reasonable to forecast costs through 2013 as any outcome from this review will not be resolved until sometime in 2013. Therefore, any outcome from this review can be addressed in the next RRA.

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177.5 Does management believe that customer education costs will be incurred indefinitely?

Response:

Customer education is critical to the successful uptake of a voluntary biomethane service offering. As indicated in the Biomethane Application, there are four main objectives for communication efforts of the biomethane service offering. They are:

1) generate awareness and understanding of biomethane as a renewable energy and its availability;

2) generate awareness and understanding of the program;

3) stimulate interest and participation in the program; and

4) maintain participation and support for the program.

Just like any new product, the FEU expect the initial communication activities to generate interest and acceptance amongst the early adopters and innovators. However to cross the chasm from early adopters to early/late majority, the FEU expect customer education to be an integral part of ongoing communication to engage current subscribers and enable new subscribers to make an informed decision to participate, especially if there is available supply. The amount of customer education and promotion activity needed will be tied closely to how much supply availability there is, which in turn drives the need to generate awareness and stimulate interest to participate in the program. Going forward, once the program reaches an accepted level of awareness and maturity and there is no more supply availability, the communication activities should subside, but a certain level of customer education will be required indefinitely in all areas to maintain a reasonable level of awareness of biomethane and participation and support for the program.

177.6 Do the customer education programs plan to target all customers in F2011? If not, which customer groups have been excluded from the customer education program?

Response:

As indicated in the Biomethane Application, Phase One of the Biomethane Service Offering to the end of 2011 is targeted at FEI residential (Rate Schedule 1) customers located in the Lower Mainland, Fraser Valley, Inland and Columbia regions. This allows the FEI to reach the largest number of customers with a single tariff offering in order to prove out demand as well as minimize costs of implementing multiple tariffs in FEI CIS system. As discussed in Biomethane Service Offering Application, Response to BCUC IR 1.18.2 (Exhibit B-3), a certain level of customer education will reach all customers, however, communicating the program will combine these educational messages with promotional messages that will be designed to motivate customers who are predisposed to support renewable energy initiatives, to enrol in the program in a timely manner. As indicated in the response to Biomethane Service Offering Application BCUC IR 1.10.5 (Exhibit B-3), customers ultimately benefit from the optimization of the FEU's system, and biomethane can assist in this goal.

177.7 What sort of customer education does management foresee for the customer education program in 2012 and 2013? Include details of the plans.

Response:

As discussed in the Biomethane Application, the availability of supply and customer uptake in Phase One, which is targeted at residential (Rate Schedule 1) customers through 2011, will be key to encouraging future development of biomethane supply and a sustainable platform from which to expand. Therefore, communication activities will be a key component for educating consumers about the biomethane program and encouraging participation in the product offering. The objectives remain the same as discussed in BCUC IR 1.177.5.

Depending on supply availability, Phase Two will either see additional residential customer education efforts, or the expansion of the offering to Rates Schedule 2 and 3 (called 2B and 3B) as currently approved as part of the Biomethane Application. The details of the customer education plan would also remain the same as provided in Appendix H of the Biomethane Application, with minor adjustments based on any lessons learned from customer education efforts in 2011 and target market requirements. Of course, if the program is fully subscribed and there is no new supply available, communication activities would be limited to a small amount of biomethane awareness and maintaining participation and support for the current subscribers.

177.8 As customers become more familiar with the biomethane program, does management foresee a reduction in the need for education? If so, please explain when management foresees this reduction.

Response:

Please refer to BCUC IR 1.177.5.

177.9 Please provide copies of the biomethane educational material planned for rollout in June, 2011.

Response:

FEI has developed educational material based on customer research and expert advice in order to achieve the objectives of the customer education plan as discussed in BCUC IR 1.177.5, which includes elements of awareness, understanding, stimulating interest and maintaining support of the program. Please refer to Attachment 177.9 for a copy of the material listed below associated with the biomethane offering:

1. Educational video
2. Web content
3. Banner Ads
4. Joint marketing material with City of Vancouver:
    a. Post Card to residential customers
    b. Website and e-newsletter blurb
5. Welcome Letter, envelope and magnet and window cling give-aways for those that enrol
6. Bookmark giveaway for events
7. Solo Banners for events
8. Facebook Ads
9. Article in corporate newsletter and Tweets

10. Emails to customers who indicated an interest in the program
11. Bill message
12. News Release

177.10 How does FEU intend to ensure that customer education programs do not include any elements of marketing for the biomethane program?

Response:

The FEU are not entirely clear what is meant by the term "marketing" in the above question.

The key elements of the FEU's customer education objectives for biomethane are explained in BCUC IR 1.177.5 which includes education and promotion of the biomethane service offering. The FEU's current customer education plan follows these objectives for the various communication pieces and costs are tracked and charged to the biomethane customer education budget appropriately. It is also the FEU'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, the FEU may have a booth at a tradeshow funded from the biomethane customer 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. Therefore, if promotion of the biomethane program is contained in any other customer education piece, then costs would be allocated appropriately to the biomethane customer education budget.

177.11 What amounts of marketing costs are forecast for the biomethane program in 2012 and 2013 as none appear to be included in this cost forecast?

Response:

The incremental costs for customer education for the biomethane program in 2012 and 2013 are $300,000 and $306,000 respectively, and can be found in Section 5.3.8.5, page 217 and detailed in Appendix J – Table J-2 (Exhibit B-1). These costs equal what was identified on page 3 of Appendix G in the Biomethane Application with an escalation factor of 2 percent for 2013.

177.12 Are any incremental marketing costs for the biomethane program being included in a biomethane deferral account?

Response:

There are no incremental marketing costs above the budgeted $160 thousand in 2010 and $240 thousand in 2011 forecasted to be included in the non-rate base biomethane program cost deferral account. Therefore, the forecast December 31, 2011 balance of the non-rate account includes the total amount of $400 thousand, as budgeted, in customer education costs.

In accordance with BCUC Order No. G-194-10, biomethane program costs including customer education costs applicable to all customers, and forecast to be incurred in 2012 and 2013, have been included in the forecast cost of service for 2012 and 2013 (and not in a biomethane deferral account) for recovery through delivery rates in each year. Please refer to Section 5.3.8.5, on page 217 of the Application which discusses the forecast program costs of $416 thousand in 2012 and $415 thousand in 2013.

178.0 Reference: Exhibit B-1, Application, p. 174 and Appendix J, Table J-2, p. 8

Biomethane - Additional headcount in the Asset Management group to support the biomethane program

On page 174 of the Application it states: *"The Asset Management group requires an analyst and assistant in 2012 ($160 thousand). Two assistants are required in 2013 ($140 thousand). These roles will support O&M, capital, sustainment planning and the NGV and biomethane programs."*

178.1 Have a portion of the additional O&M costs been allocated to the biomethane program and identified in Table J-2?

Response:

Yes, approximately 2 percent or less of this amount could be attributed to the Biomethane program and is captured in the O&M costs in Table J-2 for interconnect facilities and the upgrader equipment. The positions are being requested to primarily support the regular gas asset management activities – maintenance plans, capital project reviews and sustainment activities.

178.2 If the answer to the preceding question is "no" then what portion of the additional O&M costs should be allocated to the biomethane program?

Response:

Please see response to BCUC IR 1.178.1

179.0 Reference: Exhibit B-1, Application, p. 175 and Appendix J, Table J-2, p. 8

Biomethane - Additional O&M within the Preventative Maintenance category to operate and maintain biomethane assets

FEI states that *"a new area within the Preventative Maintenance category is the budget to operate and maintain … biomethane assets"* and that *"Starting in 2012, the O&M costs will be forecast in Distribution, and as the number of biomethane assets increase, the operation and maintenance requirements will increase. The Mainland requires $23 thousand in 2012 and an incremental $68 thousand in 2013 to operate and maintain the biomethane assets. A summary of all biomethane costs and revenues is included in Appendix J."*

179.1 Are the O&M costs required to operate and maintain the biomethane assets recovered from all customers through the revenue requirement, or only from biomethane customers?

Response:

Pursuant to BCUC Order No. G-194-10, O&M costs required to operate and maintain interconnect facilities are recovered from all customers through delivery rates and O&M costs associated with the upgrader equipment are captured in the BVA and recovered only from Biomethane customers.

179.2 In Table J-2, please identify the incremental costs related to the Preventative Maintenance category.

Response:

The costs of $23 thousand in 2012 and further incremental costs of $68 thousand in 2013 related to the preventive maintenance category are for the interconnect facilities as illustrated in Table J-2 in the Application (Exhibit B-1). The $23 thousand is the $22,500 shown under "Interconnect Facilities - Materials and Supplies" for 2012, but was rounded up to $23 thousand for the purposes of the referenced text. The $68 thousand is included, along with other costs, in the $90 thousand shown under "Interconnect Facilities - Materials and Supplies" for 2013. Please see BCUC IR 1.183.4 for additional details on the breakdown of the proposed costs.

180.0 Reference: Exhibit B-1, Application, p. 212

Biomethane - ES&ER costs related to the Biomethane Service Offering for 2012 and 2013

On page 212, FEI states that “the approved ES&ER costs related to the Biomethane Service Offering for 2012 and 2013” require additional incremental resources.

180.1 Why does FEI believe that the ES&ER costs related to the Biomethane Service Offering for the period 2012 and 2013 have been approved by the Commission?

Response:

FEI did not intend to suggest that costs to be incurred in 2012 and 2013 were previously approved by the Commission, and apologizes for the confusion that appears to have arisen from the phrasing of the referenced sentence. The referenced ES&ER costs were those discussed in the Biomethane Application and approved for 2010 and 2011 in Commission Order G-191-10. The Biomethane Application articulated that these costs were expected to continue into 2012 but did not request specific approval of costs for 2012.

The costs are related to the Biomethane Service Offering with the expectation that the offering will continue into 2012 and 2013, with inflation as the force driving small incremental increases. In this Application, FEI is requesting approval of these costs for 2012 and 2013, inclusive of the incremental amount for inflation

The biomethane service offering approved by the Commission in December of 2010 was launched in June of 2011. In Order G-191-10 the Commission approved long-term purchase agreements for biomethane, which FEI expects to sell to customers. While the biomethane service offering is under a two-year pilot, FEI does not expect to file the report analysing the pilot until the end of 2012, and as such, the program will continue to exist and incur the forecast O&M costs while the report is being reviewed through to a Commission process in 2013. Any future outcomes from this review of the biogas program can be taken into consideration in the next revenue requirements application.

180.2 Which directive in the Decision accompanying Order G-194-10 states that the ES&ER costs related to the Biomethane Service Offering for the period 2012 and 2013 are approved by the Commission?

Response:

Please see our response to BCUC IR 1.180.1.

181.0 Reference: Exhibit B-1, p. 239 and Appendix J, Table J-2, p. 8

Biomethane - Incremental Operations Support costs related to the Biomethane Service Offering for 2012 and 2013

FEI requires one additional head count part way through 2012 at an incremental cost of $52 thousand to *"support growth in the business, including new biomethane and NGV programs."*

181.1 What is the full year's cost of this additional head count?

Response:

The $52 thousand for this additional headcount part way through 2012 was based on a full year cost of $106,713. The additional head count that is required will be split to support TES projects that will be charged to the TES deferral account with the remaining $52 thousand of this amount being evenly split between the biomethane and NGV refuelling activities. This represents the additional work required of procurement to support these programs and FEI expects this type of work to continue for Biomethane, NGV, and TES projects in 2012 and 2013.

181.2 Has a portion of the cost of this additional head count been allocated to the O&M costs forecast in Table J-2?

Response:

The incremental cost of $52 thousand related to Operations Support, of which $26 thousand is applicable to biomethane and $26 thousand is applicable to NGV, was inadvertently excluded from Table J-2 as well as Table I-7, in Appendix I of the Application (Exhibit B-1). Please refer to BCUC 1.188.1 for O&M costs pertaining to Biomethane that includes this amount.

Amended tables for Appendix I and Appendix J, inclusive of this $26 thousand are provided below:

Revised Table I-7: NGV Annual Distribution O&M Requirements for Fueling Stations

	NGV Annual O&M Requirements for Fueling Stations (in thousands)		
Transportation Rate Schedule	**2011**	**2012**	**2013**
CNG			
Rate Schedule 6	$0	$15	$30
Rate Schedule 23	$0	$15	$30
Rate Schedule 25	$0	$75	$100
LNG			
Rate Schedule 16	$0	$120	$180
Other			
Operational Support	$0	$26	$26
Total:	**$ -**	**$ 251**	**$ 366**
Annual Incremental:	**$ -**	**$ 251**	**$ 115**

Revised Table J-2: Biomethane O&M Costs Summary

FEI Biomethane O&M Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013****
O&M Costs - All Customers					
Labour Costs	125,000	32,297	125,000	102,000	104,040
Computer Costs	-			10,000	
Customer Education	400,000	4,600	400,000	300,000	306,000
Internal Reporting Charges	3,200		3,200		
Inbound Calls	35,900		35,900	6,384	6,512
Rate Changes	4,000		4,000		
Application Support	165,600		165,600		
			-		
Interconnect Facilities*					
Labor*****				26,000	26,000
Materials & Supplies	49,500	1,163	49,500	22,500	90,000
Total O&M Costs - All Customers	**783,200**		**783,200**	**466,884**	**532,552**
O&M Costs -Biomethane Customers					
Upgrader Equipment**					
Materials & Supplies	70,000		70,000	123,000	237,000
Customer Related					
Energy Peace Application Support	23,280		23,280		
Enrollment Confirmations (mailings)	3,000		3,000	4,824	4,920
Customer Drops/Finalizations	10,455		10,455	32,080	32,722
Credits to Customers for Heat Content Adjustments	54,000		54,000		
Reporting & Adminnistration	4,963		4,963		
Process for Updating Premise Heat Zone in New CIS system***				20,000	
Total O&M Costs - Biomethane Customers	**165,698**		**165,698**	**179,904**	**274,642**

* O&M costs for interconnect facilities includes for Catalyst and CSRD and future projects under consideration

** O&M costs for upgrader includes for CSRD and future prc

*** One time adjustment cost

****2013 forecast has been adjusted by an inflation factor of 2% from the 2012 estimates.

*****Incremental cost of operations support

Revised Table J-5: 2010 / 2011 Biomethane Program Accounts (O&M and Other Revenue)

	($000's)				
	2010	**2011**	**2012**	**2013**	**2014**
2010 / 2011 Biomethane Program Accounts					
O&M Deferral Account					
Program O&M Activity	$ 1.2	$ 783.2			
Biomethane Service Application Costs	-	260.0			
Total	1.2	1,043.2			
Tax Offset	(0.3)	(276.4)			
AFUDC	0.1	39.4			
Net Additions	1.0	806.2			
Amortization	-	-	(269.0)	(269.0)	(269.0)
Balance	$ 1.0	$ 807.1	$ 538.1	$ 269.0	$ -
Biomethane Program Costs - Other Revenue					
Depreciation	$ -	$ 45.3			
Income Tax	-	8.8			
Earned Return	-	36.0			
Other Revenue	-	44.8			
Amortization	-	-	(30.0)	(30.0)	(30.0)
Balance	$ -	$ 90.1	$ 60.1	$ 30.0	$ -

182.0 Reference: O&M Costs

Exhibit B-1, Application, Appendix J, Part 3.2, p. 7

Biomethane

In the financial schedules accompanying the original Biomethane Application, some O&M costs associated with interconnection facilities were erroneously included in the forecast Biomethane Energy Recovery Charge ("BERC"). As a result, the BERC was calculated to be slightly higher[4] than it should have been based on the Commission-approved approach and the levelized impact on all customers was calculated to be immaterially lower than it should have been. FEI is proposing to defer addressing this miscalculation until the BERC is next changed through the approved process, whereby costs and recoveries will be reviewed on an annual basis as part of FEI's 4th quarter gas cost report to the Commission and any changes to the BERC will be based on deferral account balances at that point in time.

182.1 What is the total impact this error will have on the deferral account?

Response:

The error was $49,500 of forecast operating costs that were applied to the Biomethane Variance Account (BVA) that should have been included in the non-rate base 2010-2011 Biomethane Program Costs deferral account. For 2011 the tax rate is 26.5 percent, so the net-of-tax transfer of this amount from the BVA to the 2010-2011 Biomethane Program Costs deferral account is $36,400.

Tables J-2, J-4, and J-5 and the 2012 projected opening balance of the 2010-2011 Biomethane Program Cost deferral account as submitted with the Application already account for this correction.

183.0 Reference: Biomethane O&M Costs Summary

Exhibit B-1, Application, Appendix J, Table J-2, p. 8

Biomethane

Under Commission Order G-194-10, the Utility was instructed to maintain distinct records for the Biomethane projects including detailed accounts and cost transfers records.

183.1 Can the Utility confirm that this information was independently tracked?

Response:

Yes the Utility confirms that this information is independently tracked. Please see the response to BCUC IR 1.183.2 for additional comments.

183.2 Is an independent general ledger maintained for the Biomethane costs included in the deferral account? If not, please explain.

Response:

FEI maintains separate records for its Biomethane Service Offering programme as directed by Commission Order No. G-194-10.

General Tracking of Costs:

Capital costs from each supply point such as Catalyst, the Salmon Arm Landfill (CSRD) and future projects are tracked through the Work Order system under a Project. The sum of the capital project costs are then shown in the plant schedules for the various Biomethane gas plant asset categories. O&M costs are generally tracked through the use of Internal Orders (IOs). The Biomethane Program Manager, asset managers and distribution services field managers are responsible for the correct coding of invoices and charges to the various accounts and orders that will be set up to capture the costs related to the biomethane program.

Costs Applicable to Biomethane Customers:

The Biomethane Variance Account (BVA) captures the variance between the cost of acquiring the supply and the recovery built into the customers' rates. Other costs charged to the BVA include operating and maintenance costs for the upgraders, depreciation provision and associated income tax and earned return. Other operating costs also charged to this account as approved by the Commission include customer enrolments, drops and finalizations. The recovery of costs in this deferral account is only from customers enrolled in the Biomethane Service Offering program, Rate Schedule 11B Contracts, and Off-System Sales of Biomethane. The account is maintained on a net-of-tax basis. In accordance with the G-194-10, each individual Biomethane project is tracked through separate IOs under the BVA.

In response to BCUC IR 1.185.1, FEI is recommending that this deferral account be treated as a non-rate base deferral.

<u>2010-2011 Biomethane Program Costs Deferral Account:</u>

For 2010 and 2011, the cost of service associated with the Biomethane Service Offering that is applicable to all non-bypass customers is captured in a deferral account. This non-rate base account captures the program O&M costs and the cost of service associated with the program's capital costs. Beginning January 1, 2012, the account balance is included in Rate Base and is to be recovered from all non-bypass customers through the delivery rates over a three-year period.

183.3 What controls and cost allocation methods has the utility implemented to ensure that Biomethane costs subject to deferral are not overlooked or allocated appropriately? Please provide copies of internal control procedures implemented to track program costs to ensure appropriate allocation.

<u>Response:</u>

Operations and accounting analysts have been informed to ensure costs related to the biomethane activity are correctly accounted for. Finance staff maintains detailed accounts of Biomethane costs that are subject to deferral. Analyses and monthly review is performed with project managers to ensure the capture of appropriate allocation of costs to the program deferral accounts for 2011 and biomethane variance deferral account for all years. In 2012 the program costs will be charged to the appropriate operating and maintenance expense, and plant depreciation expense. The O&M biomethane program expenses in 2012 and following years will be tracked by specific Internal Orders within the accounting system. The costs that are included in the Biomethane Variance Account will continue to be charged to this deferral account post 2011. Regarding the Biomethane Variance Account, as part of quarterly gas cost reports the Commission has the opportunity to review the reported activity of this account for the purchase of biomethane, recoveries from customers and operating and maintenance costs.

The Commission will also be reviewing the next report on the 'test period' for the biomethane activity as well. In the fourth quarter of 2012, FEI Internal Audit will complete the Post Implementation Review which will be filed with the Commission as per the Commission Decision and Order G-194-10, page 55-56.

FEI has also hired a dedicated program manager as approved in the Biomethane decision to manage the overall program and ensure costs are charged to appropriate accounts in line with Commission decision and manage the communication and relationship with customers, suppliers and other stakeholders. In addition, management, as part of their oversight responsibility, will be reviewing the actual results compared to planned activity and costs on a regular basis.

FEI is satisfied that staff and management have in place the knowledge and review procedures to ensure that all costs charged to the biomethane accounts are appropriate and correctly recorded in order for the FEI to be in compliance with the Commission order approving the Biomethane project. There are no internal documents on control procedures for tracking program costs.

The forecast includes an amount for materials and supplies which is projected to increase in the future.

183.4 Please breakdown this amount by facilities and major components.

Response:

The forecast for materials and supplies are broken out by interconnect facilities allocated to all customers and for the upgrader equipment for the Biomethane customers only.

O&M for Interconnect Facilities: All Customers

The estimated costs for Interconnect Facilities including labour are broken down approximately as follows

Instrumentation (calibration, gases)	50%
Odorizer	25%
Other (filters, meters, regulators)	25%

For the year 2011, it is expected that the Catalyst interconnection facilities will be in operation for the full calendar year, but the Salmon Arm interconnection facilities will not be in operation until the last month of the year. The actual costs to operate the Catalyst interconnection facilities are also projected to be below the originally estimated amount. Therefore, the actual O&M costs are expected to be below the originally approved amount for 2011.

This is a result of two main factors: the Salmon Arm facility has been delayed, and the actual costs are coming in lower than expected.

In the years 2012 and 2013, costs for both Catalyst and Salmon Arm are expected to be incurred for a full year. In addition, it is anticipated that in late 2012 and in 2013, FEI will add interconnection facilities that drive the additional projected O&M costs.

O&M for Upgrader: Biomethane Customers

The major materials and supply costs for Biomethane customers include the cost of electricity for operation of the Biomethane plants.

At the projected supply levels, electricity costs can account for more than 50 percent of the total costs of operation but this relative amount can vary according to actual gas flow. The primary use of electricity is for gas compression, pumping, valve actuation and controls. The remainder of the costs are labour and materials required for operation, change out of spent media, compressor, and component maintenance.

The increase in costs in 2012 and 2013 is due to an increase in number of plants necessary for an increase in expected supply.

183.5 What amount does management expect to incur for materials and supplies once the projects have been completed?

Response:

As mentioned in BCUC IR 1.183.4, for the existing projects the FEU expect the actuals for O&M in 2011 to be well within the approved amount. However, going forward as new supply projects are developed according to the estimated supply curve, the FEU expect to incur costs for materials and supplies to maintain the existing assets and support the new ones. The amounts projected in 2012 and 2013 in Table J-2 in the Application (Exhibit B-1) are the best estimates the FEU currently have and are expected to be fully incurred. As the FEU gain experience from the current and proposed projects over the pilot period, we would be able to better project future costs by incorporating the learnings from existing ones.

184.0 Reference: Biomethane Actual Program New Deferral Accounts

Exhibit B-1, Application, Appendix J, Table J-3, p. 9

Biomethane

The table indicates that in 2010 and from January to March 2011, pipeline-ready biomethane purchases have been made and deferred.

184.1 Please explain why pipeline –ready biomethane purchases have been made before customer delivery has occurred?

Response:

As discussed in the Biomethane Application, dated June 8, 2010, and also referenced in the response to BCUC IR 1.184.2, at the time of the Biomethane Application it was anticipated that the sale of biomethane to core customers electing to participate in the Biomethane Program would begin in early 2011 even though biomethane supply was expected prior to that time.

The sale of biomethane to customers is based on a notional sale of the green attributes of the biomethane gas with the actual volumes and costs of the biomethane available for sale being tracked in the Biomethane Variance Account ("BVA"). The BVA accounting treatment was approved by the Commission in the Biomethane Application decision. Timing differences between the purchases of the physical biomethane gas and the sales of the notional biomethane are a component of the program model. The intent was to have biomethane supply lead sales in order to build a small cushion of biomethane to help manage any risk of undersupply, while any excess oversupply of Biomethane would be dealt with via sales to On System or Off System customers.

184.2 Did FEI originally foresee customer delivery occurring during this period of pipeline-ready biomethane purchase?

Response:

At the time the Biomethane application was filed, the FEU anticipated the initial launch of the program beginning in fall 2010 based on the regulatory timetable proposed in the application. Based on this timetable, the FEU did foresee customer delivery occurring during the period of January to March 2011. Also the FEU wanted to build some safety margin in supply ahead of the launch of the program in June 2011. Please refer to the response to BCUC IR 1.184.1 for more details.

184.3 What is the total purchase value, in dollars, expected to be incurred and deferred in this account before the first customer offering is made (expected in June 2011)?

Response:

The total net-of-tax cost charged to the BVA at the end of May, 2011 is $174 thousand.

The first sale of biomethane will take place in June, 2011; the following table shows the actual costs charged to the BVA account up to May, 2011. The biomethane purchases in 2010 and up to May, 2011 total $228 thousand, and the total operating and maintenance cost for updating premise heat values within the billing system is $24 thousand. The after tax cost for these two items is $184 thousand. A monthly credit provision, which began in February, based on the forecast cost from the Biomethane Application (Appendix J-3, Schedule 10) for the depreciation provision of the upgrader equipment, amortization of the CIAC, income tax and earned return has also been booked to the BVA account. This provision will be trued up at the end of the year once actual costs for the upgrader in Salmon Arm are known.

	Actual Cost ($000's)						
		2011					
Particulars	2010	Jan	Feb	Mar	Apr	May	Total
Biomethane Purchases	$ 59.6	$ 28.1	$ 21.9	$ 41.6	$ 38.0	$ 38.9	$ 228.1
Biomethane Sales	-	-	-	-	-	-	-
O&M	-	-	-	-	8.3	15.6	23.9
Subtotal	59.6	28.1	21.9	41.6	46.3	54.5	252.0
Tax Rate	28.50%	26.50%	26.50%	26.50%	26.50%	26.50%	
Tax Offset	(17.0)	(7.4)	(5.8)	(11.0)	(12.3)	(14.4)	(68.0)
Non Tax Affected Cos of Service Provision (Depreciation, CIAC Amortization, Income Tax & Earned Return re Upgrader Equipment)	-	-	(2.6)	(2.6)	(2.6)	(2.6)	(10.4)
Total Monthly Activity	$ 42.6	$ 20.7	$ 13.5	$ 28.0	$ 31.4	$ 37.5	$ 173.6
Cumulative Total	$ 42.6	$ 63.3	$ 76.8	$ 104.7	$ 136.2	$ 173.6	

185.0 Reference: Appendices

Exhibit B-1, Application, Appendix J – Biomethane Report, p. 1

Biomethane Variance Account

"As part of the Biomethane Decision, the Commission further approved the creation of a non-rate base deferral account, Biomethane Variance Account ("BVA"), to capture costs to procure and process consumable biomethane gas as well as revenues collected through biomethane energy recovery components of rates." [Ref: p.1] [Emphasis added]

"The Commission Panel approves the creation of a ***rate base*** *deferral account, called the Biomethane Variance Account, as proposed by Terasen." [Ref: G-194-10 Biomethane Decision, Part 5.1, p. 58]* [Emphasis added]

"(c) a ***rate base*** *deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences (the "Biomethane Variance Account")." [Ref: G-194-10 Biomethane Decision, Appendix A, p. 5] [Emphasis added]*

185.1 Please confirm the Company's understanding of the type of deferral account desired, requested and approved by Commission Order G-194-10 for the Biomethane Variance Account.

Response:

This response is in reply to BCUC IR 1.185.1 and BCUC IR 1.185.2.

FEI acknowledges the quoted sentence should have read "As part of the Biomethane Decision, the Commission further approved the creation of a rate base deferral account". While FEI does not object to whether this account is treated as rate base or non-rate base, due to the low materiality of the account balances as shown in Table J-4, FEI believes the proper treatment would be to recognize and account for the costs as a non-rate base deferral for the following reasons:

1. The BVA deferral is charged for the earned return, income tax, depreciation and operating and maintenance expense related to the upgraders (see FEI responses to BCUC IR 1.37.1 and 1.37.5 regarding the Biomethane Service Offering Application, filed August 6, 2010). By including the BVA in Rate Base an earned return will be calculated on a derived earned return from the upgrader equipment.

2. By treating the BVA as a non-rate base account it makes it more transparent that the cost recovery for the biomethane, upgrader(s) and costs for enrolling, removing customers, moves, billing adjustments and adjustments for heat content is only from those customers enrolling in the Biomethane service offering.

In this Application, the BVA account has not been included in the Rate Base Deferred Charges of FEI. The only change to the BVA FEI is requesting, at this time, is to treat the BVA as a non-rate base deferral. If the account balance was to materially increase in the future then FEI may wish to charge AFUDC on the net-of-tax portion of the balance related to biomethane purchases, recoveries from sale of biomethane, operating and maintenance costs and property taxes. The request to apply AFUDC could be made in the quarterly reviews of the account.

FEI has update the draft form of final order as provided in the response to BCUC IR 1.130.1, Attachment 130.1 to reflect this.

185.2 Please confirm the Company is not requesting any change with respect to the Biomethane Variance Account in this Application.

Response:

Please refer to BCUC IR 1.185.1.

186.0 Reference: Appendices

Exhibit B-1, Application, Appendix J – Biomethane Report, pp. 1-11

Biomethane Project

186.1 Please provide the allocation of CIAC shown in Table J-1 between the capital charged to All Customers and that charged to Biomethane Customers for each timeframe shown.

Response:

In accordance with BCUC Order No. G-194-10, the allocation of the CIAC is entirely to biomethane customers because the CIAC was received for upgrader plant. The capital cost of service associated with upgrader plant is included in the BVA and recovered through the BERC rate. There is no CIAC related to biomethane plant forecast for 2012 and 2013.

186.2 Please explain the basis of the $35,900 for Inbound Calls shown in Table J-2. Please confirm if these are an allocation on a unit cost basis of Customer Service Call Centre calls referred to in the Biomethane project.

Response:

FEI confirms that Inbound Calls are the cost of handling customer inquiry calls and based on a unit cost basis for the Biomethane program. In 2011 these calls will be handled under our agreement with CWLP and then in 2012 internally at FEI. In the original Biomethane Application in Tables G-1 and G-2, FEI proposed the basis for $35,900 for handling inbound calls and proposed the appropriate cost allocation methodology described in section 10 of the Biomethane Application. The BCUC approved this cost allocation methodology in Commission Decision and Order No. G-194-10 in December 2010 (Page 51 of the Decision). FEI has provided additional details below for the basis of estimating $35,900 for inbound calls.

Based on 1 percent uptake of the eligible customers for Biomethane program and through historical analysis, CWLP estimated anywhere from 1,800-5,400 minutes per month for the inbound calls. Assuming 1,800 minutes per month on the lower end at an average cost of $1.33 per minute, FEI has estimated approximately $2,394 per month. Multiplying this on an annual basis, FEI has estimated $28,728 for the entire year of 2011.

At the time the Biomethane Application was filed, FEI also requested approval of costs from October 2010 to December 2010. Applying the same assumptions as above, the monthly cost of $2,394 is multiplied by 3 months to yield $7,182.

The costs for all of 2011 and three months of 2010 were estimated at $35,900. Since FEI delayed the launch of the program until June 2011, the costs associated with inbound calls will be tracked on an actual basis once the program opens up for enrollment in June 2011 until the end of the year. FEI will provide an update at the end of the test period and accordingly update the deferral account balances.

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186.3 Please confirm whether the "Application Support" costs of $165,600 shown in Table J-2 are for the Biomethane Application that resulted in Commission Order No. G-194-10. If these costs are not for this application, please describe what these costs relate to.

Response:

The one time "Application Support" costs of $165,600 shown in Table J-2 in this Application (Exhibit B-1) are not for the Biomethane application that resulted in Commission Order No. G-194-10. The Application Support cost shown in Table J-2 is part of the total program costs that were approved in the Biomethane Decision and are the costs to program, configure and update the current billing system to allow the launch of the Biomethane service offering for residential customers.

186.4 Please explain the Interconnect Facilities Materials and Supplies projected for December 31, 2011 of $49,500 shown in Table J-2 and confirm these are not double counted by the new Biomethane related O&M requested in Part 5 of the Application by the Operations groups.

Response:

The materials and supplies of $49,500 shown in Table J-2 in this Application (Exhibit B-1) is for odourant, periodic examination of meters and regulators to ensure they are working properly (including gas quality monitoring). The cost also includes labour and materials for instrumentation set up, and for process adjustments for pressure and valve settings.

FEI confirms that the Biomethane interconnect facilities costs are not double counted. Although shown on the same row for comparison purposes, the work done in 2011 on Biomethane Interconnect Facilities is charged to the O&M Program Costs deferral account and is not included in the Distribution Operations operating and maintenance expense for 2011. As with other Biomethane program costs, the deferral account treatment of the interconnect facilities materials and supplies costs ends effective December 31, 2011 and the forecast costs for 2012 and 2013 are included in the cost of service and recovered through rates in each year, respectively. That is, the forecast 2012 and 2013 costs are not included in the deferral account balance and are only included in the forecast O&M, as outlined in Section 5.3.5 of the Application.

186.5 The upgrader capital cost of $1.934 million (per Table J-1) divided by the depreciation of $387,200 (per Table J-4) yields 5 years. Please explain if the five year depreciation rate is the result of a depreciation study for these assets, or is based on the original program request of five years (reduced to two years in Commission Order No. G-194-10) or is on some other basis.

Response:

The depreciation rate used for upgrader plant is based on manufacturers' suggested plant life expectancy with a major overhaul approximately every 7.5 years.

In the Application (Exhibit B-1), Table J-4, the depreciation provision is the summation of the depreciation on the upgraders and the CIAC amortization. As noted at the bottom of the table, the CIAC amortization was overstated due to including the CIAC transferred from Lions Gate twice in the amortization calculation. The effect is an increase to the depreciation of the upgrader plant by $3.4 thousand in 2012 and 2013. This was an error in Table J-4 only and does not affect the financial schedules in Section 7.1.

The derivation of the depreciation and amortization expense in Table J-4 is provided in the table below:

		2011	2012	2013	
Gas Plant In Service Additions for Upgraders					
Upgrader		$ 1,547.2	$ 1,650.0	$ 2,050.0	
Upgrader Overhaul 20% Total		386.8	412.5	512.5	
Total Upgrader Addition		1,934.0	$ 2,062.5	$ 2,562.5	Table J-1
AFUDC					
Upgrader		$ 60.3			
Upgrader Overhaul 20% Total		15.1			
Total AFUDC		75.4			
Total Additions		$ 2,009.4			
Mid-Year Plant					
Upgrader		$ 803.8	$ 2,432.5	$ 4,282.5	
Upgrader Overhaul		200.9	608.1	1,070.6	
Total Upgrader Addition		$ 1,004.7	$ 3,040.7	$ 5,353.2	
Contributions in Aid of Construction					
Transfer from Lions Gate		$ (50.4)			
ICE / BCBN Funding		(515.6)			Table J-1
Total CIAC		$ (566.0)			
Depreciation Provision					
Upgrader	6.67%	$ 9.1	$ 162.2	$ 285.6	
Upgrader Overhaul	13.33%	4.5	81.1	142.7	
CIAC	6.67%	(20.6)	(37.8)	(37.8)	
Total Annual Depreciation Provision		**$ (6.9)**	**$ 205.6**	**$ 390.6**	Table J-4

Table J-4 as filed had inadvertently double counted the $50.4 CIAC transfer from Lions Gate Project

186.6 Please provide further details on the Biomethane Program Costs – Other Revenue in Table J-5, including the types of assets being depreciated, the depreciation rate(s) applied, and items included in "Other Revenue."

Response:

As reflected in Table J-5 (Application, Exhibit B-1), "Other Revenue" includes the implicit earned return and income tax amounts of $36 thousand and $8.8 thousand related to the interconnect facility assets of the biomethane program. The types of distribution assets being depreciated are listed in the table below along with the projected 2011 depreciation provision for those assets. The table also includes the determination of the earned return and income tax amounts.

Depreciation on the plant accounts used for the biomethane program, other than the upgrader equipment, and incurred prior to December 31, 2011, is charged to the non-rate base biomethane program costs deferral account that was set up to capture the cost of service associated with program capital. The value of the implicit earned return and income tax is credited to Other Revenue and is also charged to the non-rate base biomethane program cost deferral account which captures the cost of service associated with program capital. This treatment is consistent with the accounting and cost allocation methodology approved by the Commission in Order No. G-194-10, dated December 14, 2010.

	2011 Additions	Dep'n Rate	# of Days	**Dep'n Provision**
Mains	$ 126	1.89%	245	$ 1.6
Measuring & Regulating	428	5.72%	245	16.4
Meters	765	5.31%	245	27.3
Total Additions	$ 1,319			**$ 45.3**
Projected Rate Base				$454.4
Return on Rate Base				7.93%
Earned Return				**$36.0**
Income Tax				
Earned Return				$36.0
Less: Utility Interest				(18.8)
Add: Depreciation				45.3
Less: CCA				(38.1)
Taxable Income After Tax				$ 24.4
Taxable Income				$ 33.2
Income Tax Rate				26.50%
Income Tax				**$ 8.8**
Class 51 @ 6%				
Additions				$ 1,319.0
Less: AFUDC				(48.0)
Additions to the CCA Class				$ 1,271.0
CCA @			6%	$ (38.1)

187.0 Reference: Appendices

Exhibit B-1, Application, Appendix J – Biomethane Report, pp. 1-11

Biomethane Project

"On December 14, 2010, the British Columbia Utilities Commission (the "BCUC" or "Commission") issued its Decision and Order No. G-194-10 (the "Biomethane Decision"), allowing FEI to move forward with a Biomethane Service Offering/Program for a two year period from the date of the Biomethane Decision and approving the two agreements with Columbia Shushwap Regional District ("CSRD") and Catalyst Power Inc ("Catalyst")." [Ref: p.1]

"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. It is important to consider this finding as a test period approval only, as another determination will be required at the point of the review for Phase 1." [Ref: G-194-10 Biomethane Decision, Part 4.9, p. 51]

"Accordingly, the Commission Panel, to safeguard the public interest, has determined that Terasen will be granted a period of two years from the date of the Order issued concurrently with this Decision for review and preparation of further applications in support of expansion of this Program." [Ref: G-194-10 Biomethane Decision, Part 4.11, p. 56]

"Based on the most recent production trends, FEI anticipates Catalyst will inject a minimum cumulative total of 59,000 GJs by the end of 2011 and reach their minimum average daily contract volumes by the end of 2012." [Appendix J, pp. 3-4]

The CSRD project … is now expected to be commissioned in late 2011 with an injection start date close to year end. Therefore, there will be no significant contribution to the biomethane supply before the end of 2011." [Appendix J, p. 4]

"However, the Panel remains concerned that the model proposed by Terasen Gas has yet to be tested in the British Columbia marketplace. In our view it would be prudent for TGI to gain knowledge and experience by a thorough testing of the Program before any firm determination can be made as to the full market potential. The two Projects will provide a reference case which will serve as a basis for future projects. Therefore, we have determined the scope of the Biomethane Program should be limited until such time as actual results can be analyzed and more definitive conclusions drawn." [Ref: G-194-10 Biomethane Decision, Part 4.5, p. 34]

187.1 With the late start of these programs, does it not make sense to continue the Biomethane related costs in the deferral accounts until the end of 2013, at which time there will be a minimum of one full year of experience with the two trial projects, the Phase 1 two year period will be over, and the reporting and public consultation will be complete?

Response:

To clarify, and in accordance with BCUC Order No. G-194-10, FEI has not proposed to discontinue the use of the BVA. We will continue to use that deferral account for the foreseeable future to capture and recover costs associated with the non-program O&M and capital Biomethane costs.

FEI does not agree that deferral account treatment for program costs (i.e. the Biomethane costs applicable to all customers) should be perpetuated until the end of 2013. FEI believes that it is most appropriate to include the Biomethane program costs in our forecast cost of service and delivery rates for 2012 and 2013 for several reasons:

- Biomethane is a component of our natural gas business and operations and should be treated consistent with other forecast costs and revenues that apply to all customers.
- The accounting treatment reflected in this Application pertaining to Biomethane Program costs in is accordance with the accounting treatment as outlined in Section 10 of the Biomethane Application (Exhibit B-1, page 111). Section 10 of the Biomethane Application included a discussion on FEI's intention to include forecast costs in the utility's rate base and cost of service in the year to which they pertain, effective January 1, 2012. This accounting treatment in Section 10 was reviewed in conjunction with the Biomethane Service Offering Application and approved by BCUC Order No. G-194-10.
- Deferral account treatment of the program costs incurred in 2010 and 2011 was required because the Biomethane Application was filed subsequent to the determination of delivery rates for 2010 and 2011. The delivery rates in place for 2010 and 2011 were set in accordance with BCUC Order No. G-141-09. Therefore, the requested and approved deferral account mechanism was the most appropriate method to capture the costs incurred in 2010 and 2011 for future recovery from customers.
- All Biomethane program costs for 2012 and 2013 will be prudently incurred and subject to Commission review through the revenue requirements process and as such, FEI does not believe that it is necessary or appropriate to defer these costs for future recovery from customers.

Finally, FEI does not expect that the outcome of the reporting and public consultation period will result in any material changes to the Biomethane program costs as forecast in this Application. As submitted in this Application, FEI believes that the 2012 and 2013 Biomethane program costs should be included in the forecast cost of service and delivery rates for 2012 and 2013, respectively, to match the time in which they have been incurred.

188.0 Reference: Biomethane Service Offering

Exhibit B-1, Application, Section 1.2.3.1, p. 13; Appendix J – Biomethane Report

Inclusion of Biomethane Revenues and Costs in this RRA

"In Commission Order G-194-10, FEI received approval to implement a two year pilot program for a Biomethane Service Offering. In that order, FEI was directed to include in this RRA the details of costs for the program."

"The planned launch of the Biomethane Service Offering is June of 2011. FEI has included the costs and related revenues for the Biomethane program for 2012 and 2013 in the O&M (Section 5.3), capital expenditures (Section 6.2). The rate base deferral for the 2010-2011 Biomethane Program Costs (Section 6.3) is also included in the revenue requirement calculation. In addition, the FEI has included a comprehensive report in Appendix J summarizing the costs incurred and deferred in 2010 and 2011 related to the program, and also providing a summary of the forecast program costs and revenues that are included in each of Section 5.3, 6.2, and 6.3."

188.1 Please summarize all capital expenditures within the RRA, such as those shown in Table 6.2-1 on p. 332 and Schedules 44 to 51 in Section 7.1, and all O&M costs within the RRA, such as those in Section 5.3.5.7 on p. 175, that relate to the Biomethane Service Offering, and reconcile these amounts to Table J-1 for capital expenditures, Table J-2 for O&M costs, and Tables J-3 to J-5 for deferral accounts in Appendix J of this RRA. Please then show how these capital expenditures, O&M costs and deferral accounts tie to Appendix G of the Biomethane Application (June 8, 2010).

<u>Response:</u>

Please refer to Attachment 188.1.

An explanation of the reconciliation of the Biomethane capital and O&M costs as well as the deferral account balances follows below.

1. <u>Biomethane Capital Expenditures and Plant Additions</u>

The reconciliation of capital expenditures and plant additions pertaining to interconnecting facilities and upgrader plant is reflected on page 1 of Attachment 188.1. As demonstrated in this schedule, the additions (excluding capitalized overhead and AFUDC) as included in the gas plant in service schedules (see references A-1, A-2 and A-3 of page 1 of Attachment 188.1) reconcile to the additions as provided in Table J-1 of the Appendix.

The following table identifies the capital expenditures in Table 6.2-1 for Biomethane and NGV and the Contributions in Aid of Construction related to Biomethane and all other capital work. The Biomethane capital expenditures in Table 6.2-1 also reconcile to the additions in the financial schedules.

Capital Expenditure for Biomethane & NGV in Table 6.2-1

	2011	2012	2013
Growth Capital			
Biomethane	$ 3,204	$ 3,078	$ 3,578
NGV	3,800	4,000	3,800
Total Growth Capital in Table 6.1-2	$ 7,004	$ 7,078	$ 7,378
Contributions in Aid of Construction			
Biomethane	$ 666	$ -	$ -
All Other	5,561	5,341	5,399
Total CIAC in Table 6.1-2	$ 6,227	$ 5,341	$ 5,399

A variance in the capital additions as compared to the Biomethane Application exists; as stated in this RRA (Exhibit B-1), the cost of the upgrader for CSRD has increased from $1.6 million to $1.9 million due to additional equipment that must be added. For the current Revenue Requirement Application there are future supply forecast for 2012 and 2013 that were not part of the Biomethane Application.

2. <u>Biomethane Operating and Maintenance</u>

Page 2 of Attachment 188.1 shows the Operating and Maintenance costs as included in the Revenue Requirement Application, RRA Appendix Table J-2, and in the Biomethane Application. As demonstrated in this schedule, the O&M expense allocated to all customers, and the O&M expense allocated to Biomethane customers, reconciles to the O&M amounts as provided in Table J-2 of the Appendix.

For ease of comparability the amounts shown from the Biomethane Application for 2010 and 2011 have been summed. The total cumulative O&M in 2011, as forecast in the Biomethane Application, was approximately $950 thousand. This reconciles to the total O&M included in the Biomethane deferral accounts of $950 thousand (i.e. the summation of both the program and non-program O&M costs). Also, as stated in the Biomethane Report in Appendix J, approximately $49 thousand of operating costs in the Biomethane application (Appendix J-1) were inadvertently included with the upgraders. A variance in the forecast 2012 O&M as compared to the Biomethane Application exists because of the additional Biomethane projects forecast for 2012.

Please note that as discussed in BCUC IR 1.181.2, an additional $26 thousand for Operations Support was omitted from the Biomethane Program costs for 2012 and 2013 in Table J-2. The financial schedules correctly included this amount.

3. Biomethane Deferral Accounts

Page 3 of Attachment 188.1 shows the deferral accounts for the program and non-program costs associated with Biomethane. In addition to the deferral additions identified in Appendix Table J-5, the FEI is also seeking recovery of the $260 thousand ($192 thousand after tax) cost of the Biomethane Application. The application cost addition is the cause of the variance between Table J-5 and the deferral account additions and amortization expense reflected on Schedule 68, Line 13 of Section 7, Tab 7.1.

The corresponding forecast deferral account balances from the Biomethane Application Appendix J-2 are also shown. Although the underlying O&M expense does not vary, the difference in the program costs deferral account balance as forecast in the Biomethane Application and the RRA is attributable to the impacts of AFUDC and income tax expense due to the delayed timing of when the costs will be incurred to make the service available.

The final schedule in Attachment 188.1 (Page 4) relates to the Biomethane Variance Account ("BVA") and provides the biomethane actual purchases included in Appendix J-3, as well as the projected purchases for the balance of 2011 and forecast purchases for 2012 and 2013. Also shown is the O&M activity related to this account, property taxes, upgrader depreciation, CIAC amortization, projected/forecast income tax and earned return related to the upgrader costs. The comparable amounts are shown from the Biomethane Application Appendix J-3. Please note that FEI did not expect the forecast balance in the BVA in this RRA to reconcile to the balance provided in the Biomethane Application as it is largely dependent on volume and timing of when the service will be available to customers to begin enrolment, and the delayed timing of the increased upgrader equipment costs.

189.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendices K-1, K-3, K-4

General Question

189.1 Please provide the working electronic Excel spreadsheets in Appendix B to Appendix K-4 and all supporting analyses. Please make sure the following information is present:

i. Government or other grants and incentives (i.e. LiveSmartBC grants)
ii. Avoided natural gas costs by component (i.e. capacity, CCF throughput and any carbon tax or environmental charge)
iii. Measures included
iv. NTG ratios, including future anticipated spillover, if applicable (listed separately)
v. Discount rates
vi. Societal Cost Test

Response:

Please see Attachment 189.1, provided confidentially under separate cover. The EEC working spreadsheet models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers. For the "Summary" files that provide results for FEI and FEVI combined, "Scenario 1" refers to the "conventional" EEC portfolio excluding Innovative Technologies, and "Scenario 2" refers to the overall EEC portfolio including Innovative Technologies. In most instances, the Companies do not track government grants; these have been provided wherever the Companies have the relevant information. In the case of LiveSmartBC, for example, the Companies do not have information as to the amount of grants provided by the Government of British Columbia. Avoided natural gas costs can be found in the "Input" tab, as can the discount rate. Measure information is provided in the individual tabs in the workbooks. NTG ratios by measure/program can also be found in the individual tabs and none of the NTG ratios include spillover. A separate spreadsheet calculating the Societal Cost Test result is also provided.

189.1.1 Please provide all inputs and assumptions used to screen existing and proposed programs. Where applicable, provide assumptions and inputs for both the TRC test and the proposed Societal Cost Test.

Response:

All inputs can be found on the "Inputs" tab in the Confidential Attachment 1.189.1 in the response to BCUC IR 1.189.1.

In 2010 and 2011, the Total Resource Cost (TRC) test analysis used the assumptions outlined in Table 1 below for **avoided costs and carbon.**

Table 1 – Avoided Costs and Carbon

Year	Incremental Cost of Gas ($/GJ)	Carbon Tax ($/GJ)
2010	$5.4988	$0.7482
2011	$6.1666	$0.9976
2012	$6.8057	$1.2470
2013	$7.3510	$1.4964
2014	$7.8667	$1.4964
2015	$8.2632	$1.4964
2016	$8.5650	$1.4964
2017	$8.7757	$1.4964
2018	$8.9865	$1.4964
2019	$9.1943	$1.4964
2020	$9.3966	$1.4964
2021	$9.6017	$1.4964
2022	$9.8114	$1.4964
2023	$10.0258	$1.4964
2024	$10.2451	$1.4964
2025	$10.4693	$1.4964
2026	$10.6986	$1.4964
2027	$10.9330	$1.4964
2028	$11.1728	$1.4964
2029	$11.4179	$1.4964
2030	$11.6685	$1.4964
2031	$11.9245	$1.4964
2032	$12.1862	$1.4964
2033	$12.4536	$1.4964
2034	$12.7269	$1.4964
2035	$13.0062	$1.4964
2036	$13.2916	$1.4964
2037	$13.5833	$1.4964

Year	Incremental Cost of Gas ($/GJ)	Carbon Tax ($/GJ)
2038	$13.8814	$1.4964
2039	$14.1860	$1.4964
2040	$14.4973	$1.4964
2041	$14.8154	$1.4964

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. Tables 2 and 3 below shows the assumed **retail rates and discount rates** for the TRC in 2010 and 2011 respectively.

Table 2 - 2010 Assumed Retail Rates and Discount Rates

FEI Residential Retail Rate	$0.0099
FEVI Residential Rate ($/MJ)	$0.0143
FEI Commercial Retail Rate	$0.0094
FEVI Commercial Rate ($/MJ)	$0.0169
Residential Electric Rate	$0.0827
Commercial Electric Rate	$0.0769
Electric Capacity Charge	$52.00
FortisBC Rate of Inflation	1.9%
BC Hydro Rate of Inflation	2.00%
FEI Discount Rate	7.38%
FEVI Discount Rate	6.87%
BC Hydro Discount Rate	6%
Participant Discount Rate	6%

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%

In 2010 and 2011, for Societal Cost Test (SCT) analyses, a 3 percent discount rate was used combined with a 30 percent adder on total benefits. The avoided commodity cost is a levelized $15.28 per GJ with a $0.16 distribution adder per GJ starting in 2010. There were no carbon tax costs included; otherwise, the assumptions for the SCT are identical to TRC analysis assumptions.

189.2 For the New Initiative programs, please provide a working electronic spreadsheet including all information in the Excel spreadsheets for existing programs, and the information requested as in the question above, as well as any additional measure level data, including:

i. Efficient technology description
ii. Baseline technology description
iii. Measure lives
iv. Incremental costs for both retrofits and market driven applications
v. Assumed penetration
vi. Any cost or savings adjustments

Response:

The information request refers to "existing programs" within the New Initiatives program area. There are no "existing programs" within the New Initiatives program area as New Initiatives have not yet been approved by the Commission. The information provided below is illustrative only, and is based on the Companies experience with these technologies in the past.

Attachment 189.2 is provided confidentially under separate cover, and contains the requested working TRC and SCT cost-effectiveness Excel workbooks along with an Excel workbook summarizing items i through vi above. The Excel models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers.

The cost-effectiveness workbooks include all cost-effectiveness assumptions including avoided costs and discount rates. Please refer to the Excel workbooks as referenced below:

- Attachment 189.2_Summary_Inputs represents the summary inputs of all New Initiative programs
- Attachment 189.2_(1)_TRC_TES_Geoexchange Schools Average represents the TRC calculation for Thermal for Schools Average
- Attachment 189.2_(1)_TRC_TES_Geoexchange Schools Elementary represents the TRC calculation for Thermal for Schools Elementary
- Attachment 189.2_(1)_TRC_TES_Geoexchange Schools Secondary represents the TRC calculation for Thermal for Schools Secondary
- Attachment 189.2_(1)_TRC_Solar Hot Water represents the TRC calculation for Solar Thermal Residential
- Attachment 189.2_(1)_TRC_Solar Air represents the TRC calculation for Solar Thermal Air
- Attachment 189.2_(1)_TRC_Solar Commercial represents the TRC calculation for Solar Thermal Commercial
- Attachment 189.2_(1)_TRC_Furnace Scrap It represents the TRC calculation for Furnace Scrap-it
- Attachment 189.2_(2)_SCT_TES_Geoexchange Schools Average represents the SCT calculation for Thermal for Schools Average

- Attachment 189.2_(2)_SCT_TES_Geoexchange Schools Elementary represents the SCT calculation for Thermal for Schools Elementary

- Attachment 189.2_(2)_SCT_TES_Geoexchange Schools Secondary represents the SCT calculation for Thermal for Schools Secondary

- Attachment 189.2_(2)_SCT_Solar Hot Water represents the SCT calculation for Solar Thermal Residential

- Attachment 189.2_(2)_SCT_Solar Air represents the SCT calculation for Solar Thermal Air

- Attachment 189.2_(2)_SCT_Solar Commercial represents the SCT calculation for Solar Thermal Commercial

- Attachment 189.2_(2)_SCT_Furnace Scrap It represents the SCT calculation for Furnace Scrap-it

The analyses show that all proposed Thermal for Schools secondary and average projects and the Furnace Scrap-It are cost-effective using a Societal test with a 3 percent discount rate, a 30 percent deemed adder, and biomethane gas prices. Solar Commercial, Solar Residential, and Solar Air are not expected to pass any screen due to the high incremental costs associated with those projects.

Some of the Thermal for Schools projects resulted in a negative value TRC. This is solely due to the geoexchange projects having an increased electric usage in relation to the natural gas GJ savings. This results in a negative benefit-cost ratio in some cases. Those cases should be viewed as non-passing benefit-cost ratios. Ideally, those alternate fuel costs would be modeled as a TRC/SCT cost and this is being addressed for future cost-effectiveness analyses. In a corrected analysis, however, these programs would not pass the selected TRC or SCT so viewing negative ratios as non-passing is appropriate.

Because the analyses are based on total resource and societal tests, incentives are not included in the cost-effectiveness analyses in this response. Inclusion of incentives would not change the results because they are treated as transfer payments under these tests.

The following is a summary of each proposed new initiative (Solar for Commercial and Residential, Solar Thermal Air, Thermal for Schools, and Furnace Scrap-It) including a description of the efficient and baseline technology, measure life of the typical project associated with the initiative, incremental costs, and anticipated participation or penetration of the initiative. The Furnace Scrap-It program includes costs and savings adjustments, which are outlined below, to account for early replacement. There are no cost or savings adjustments associated with solar or thermal projects for schools. The initiatives described below reduce overall natural gas consumption, but do not completely replace consumption of natural gas at the site.

Thermal Energy for Schools

Thermal Energy for Schools provides incentives for the installation of ground source heat pumps. These systems replace the existing heating and cooling system for elementary and secondary schools, which will vary by site. The assumed measure life is 20 years and the typical incremental cost is expected to be approximately $525,000 per site. At this time, the FEU cannot provide projected participation, but expects to process fewer than 200 rebates annually.

Solar Residential

This program installs solar direct water heating systems in residential homes. The primary components of the installed system are a solar collector, a heat transfer fluid, and an insulated storage tank. Due to the climate, active closed-loop systems are installed for a typical project. The systems use a pump to circulate non-freezing heat-transfer fluid through the collectors and then through a heat exchanger in order to transfer the thermal energy to the water. The baseline is the existing gas hot water heater. The average useful life for solar hot water is 25 years and the incremental cost is $7,500. The FEU anticipate 400 installations under this program annually.

Solar Air

Solar Air is directed at commercial and industrial customers and incents the installation of solar walls in order to preheat ventilation air. The solar walls consist of cladding placed on a side of the building with southern exposure. The baseline assumes that 1,500 CFM of supply air is heated by a natural gas source at 80 percent efficiency (78 percent seasonal). The typical project is expected to cost $39,400 with a measure life of 25 years. The FEU anticipate twelve site installations annually under this program.

Solar Commercial

This program installs solar direct water heating systems for commercial applications such as schools, universities, apartments and hospital. The primary components of the installed system are a solar collector, a heat transfer fluid, and an insulated storage tank. Due to the climate, active closed-loop systems are installed for a typical project. The systems use a pump to circulate non-freezing heat-transfer fluid through the collectors and then through a heat exchanger in order to transfer the thermal energy to the water. The baseline is the existing gas hot water heater or gas boiler. The average useful life for solar hot water is 25 years and the incremental cost is approximately $55,000. The FEU anticipate fifty installations under this program annually.

Furnace Scrap-It

The Furnace Scrap-It program provides incentives for early replacement of working, inefficient gas furnaces. The installed efficient equipment has an AFUE of 96 percent and the assumed baseline is a 77 percent AFUE gas furnace. The expected useful life is 18 years and the incremental cost is $3,708. The FEU project there will be 8,500 installations under this program annually. The measure cost has been adjusted to account for the total cost of the furnace installation, rather than the incremental cost and includes the cost savings to the customer when the original furnace would have failed. Similarly, the savings have been adjusted to reflect savings between the existing furnace and efficient furnace for the remaining expected useful life of the equipment, after which only the incremental savings between the current baseline and installed equipment is included.

189.3 How were avoided gas costs used in the Company's TRC calculations? What actual costs do they represent and how were such costs avoided?

<u>Response:</u>

The use of avoided costs used in the Companies' TRC calculation's is consistent with the California Standard Practice Manual[27], excerpted below, and represents the benefits from avoided supply costs for a load reduction program such as the efficient boiler or heating system upgrade program.

> *"The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant."*

[27] California Standard Practice Manual, July 2002, p. 18

When a GJ is saved by a customer as the result of an EEC initiative, the Utility does not have to pay for commodity, tolls, transportation costs and system improvement charges. For high-carbon fuel switching programs such as oil to natural gas conversion, the avoided cost is the higher-carbon fuel, and the net benefit used in the TRC calculation is the differential between the avoided higher-carbon fuel cost, and the incurred natural gas cost.

Assumptions for avoided costs of natural gas consumption are currently based upon information from the FEU's Gas Supply group, and avoided costs are updated quarterly. The avoided cost of gas on a per unit basis includes two components - an estimate of the commodity cost and an estimate of the midstream cost. The commodity cost is based on the 10 year AECO price forecast according to GLJ Petroleum Consultants (an independent energy consultant) based on their latest available forecast (updated by GLJ each quarter). The midstream costs are estimated by calculating an approximation of the pipeline transportation charges required by the FEU to move the commodity supply to core markets as well as the storage costs associated with meeting winter load requirements. These midstream costs are then increased by an assumed inflation factor of 3 percent to account for the expected future cost increases of these resources. This resulting avoided cost represents the expected marginal cost of gas (including commodity, transportation and storage resources) to serve the FEU customers on a per unit basis. Carbon tax at known rates (i.e. those announced by government so far) and current approved system improvement charges are also accounted for in avoided costs for evaluating EEC programs, and is also included in the total avoided cost.

As this method of calculating the avoided cost of gas can fluctuate, the Companies are proposing moving ahead with using the ceiling price for biomethane for all programs except the NGV incentive program as the avoided cost in order to reduce fluctuations in the amount of EEC that is considered to be "cost-effective", and more closely align the avoided cost used to analyze EEC activity, which is environmentally benign, with the cost associated with other environmentally benign energy sources. For information regarding the Company's views on the appropriate avoided cost for the NGV program, please see the responses to BCUC IRs 1.199.6 and 1.200.1.

189.4 Does the FEU include the carrying costs of EEC expenditures in its TRC calculations?

Response:

No, FEU does not explicitly include carrying costs associated with EEC expenditures in its TRC calculations. FEU understands that neither BC Hydro nor FortisBC Inc. (electric) include carrying costs associated with EEC expenditures in TRC calculations. Please see the response to BCUC IR 1.193.1.1.

189.5 How are LiveSmartBC incentives treated in the FEU's cost effectiveness screening? Are they an input into the TRC?

Response:

As noted in the response to BCUC IR 1.189.1, the Companies do not track LiveSmartBC incentive amounts. Therefore, they are not included in the Companies TRC calculations.

190.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendices K-1, K-3, K-4

General Question

190.1 Please provide in matrix format the following information:

i. For existing programs offered jointly with LiveSmartBC:

  i. Program name(s)
  ii. Markets addressed (residential, commercial, industrial and also by retrofit vs. lost opportunity)
  iii. Incentive budget (listed separately by LiveSmartBC and the FEU)
  iv. Non-incentive budget (listed separately by LiveSmartBC and the FEU)
  v. Allocation of energy savings between LiveSmartBC and FEU

Response:

The FEU are partners in current iterations of the LiveSmartBC: Efficiency Incentive Program for residential retrofits by supporting building envelope incentives as outlined in BCUC IR 1.215.4. The FEU and Ministry of Energy and Mines are finalizing participant data for the program that launched April 1, 2010 through March 31, 2011 and are supporting the current iteration that launched April 1, 2011 which may remain in market through March 31, 2013 contingent upon funding. Please note that these contributions are estimates only until final invoices are received from the Ministry of Energy and Mines. The FEU are unable to identify the LiveSmartBC budget in the table below as the FEU do not have access to information pertaining to the contributions to LiveSmartBC from the Ministry of Energy and Mines.

Existing Programs Offered Jointly with LiveSmartBC - 2011 Forecast

Program	Markets Addressed	Incentive Budget ($000)		Non-incentive Budget ($000)		Allocation of Energy Savings *	
		LiveSmartBC	FEU	LiveSmartBC	FEU	LiveSmart	FEU
LiveSmart BC Home Retrofits - 2010 Launch	Residential Retrofit	N/A	557	N/A	100	GHG emission reductions	100% of gas savings
LiveSmart BC Home Retrofits - 2011 Launch	Residential Retrofit	N/A	1,755	N/A	180	GHG emission reductions	100% of gas savings

Please note that budget numbers are an estimate only and will be dependent on 2010 final invoicing from Ministry of Energy and Mines and 2011 program participation
* The final allocation of savings and GHG emission reductions is currently under discussion with Ministry of Energy and Mines

ii. For existing programs offered jointly with BC Hydro:
   i. Program name(s)
   ii. Markets addressed (residential, commercial, industrial and also by retrofit vs. lost opportunity)
   iii. Incentive budget
   iv. Non-incentive budget
   v. Annual and cumulative energy savings
   vi. Allocation of energy savings between BC Hydro and the FEU

Response:

The FEU partner with BC Hydro on DSM programs whenever possible, in order to share program administration and evaluation costs and to provide a good customer experience. When collaborating on these programs, the FEU pay incentives and capture savings for natural gas heated homes and BC Hydro pays incentives and captures savings for homes with electrical heating. For programs such as high-efficiency washers, the FEU pay incentives and capture savings for customers with natural gas water heating appliances and BC Hydro pays incentives and captures savings for customers with electric water heating appliances. The FEU continue to partner with BC Hydro and has several initiatives still in development. The FEU do not have access to information pertaining to BC Hydro contribution amounts.

Existing Programs Offered Jointly with BC Hydro - 2011 Forecast*

Program	Markets Addressed	Budget ($000)		Energy Savings		Allocation of Energy Savings	
		FEU Incentive	FEU Non-Incentive	Annual (GJ/yr)	Cumulative	FEU	BCHydro
LiveSmart BC Home Retrofits	Residential Retrofit	1,755	180	44,573	474,721	100% of gas savings	100% of electrical savings
High Efficiency Appliances	Residential Retrofit	365	65	20,805	180,324	100% of gas savings	100% of electrical savings
Energy Savings Kits	Affordable Housing	110	123	6,584	39,174	100% of gas savings	100% of electrical savings
REnEW	Affordable Housing	N/A	185	N/A	N/A	N/A	N/A
Public Sector Energy Conservation Agreement ("PSECA") Initiative	Public Sector Retrofit	1,008	33	36,327	381,585	100% of gas savings	100% of electrical savings
Energy Specialist Program**	Enabling Activities	1,320	1	N/A	N/A	N/A	N/A

* does not include the Low Income Partnership Grant that the Companies received from MEM in March 2009
** BC Hydro does not contribute any dollars to the budgets listed but assists with management of the program and therefore is still considered to be a partner

iii. For existing programs offered solely by LiveSmartBC:
    i. Program summary description, objectives, and savings goals.
    ii. Markets addressed (residential, commercial, industrial and also by retrofit vs. lost opportunity)
    iii. Incentive budget
    iv. Non-incentive budget
    v. Annual and cumulative energy savings

Response:

According to the Ministry of Energy and Mines, currently there are no LiveSmartBC programs that they offer as stand-alone programs. The FEU are either currently partnered or, as is the case in the LiveSmartBC: Small Business program, are in discussions on ways to collaborate on all LiveSmartBC initiatives for which there are natural gas savings. Please refer to BCUC IR 1.190.1.1 for an overview of the current FEU's programs in collaboration with LiveSmartBC.

iv. For existing programs offered solely by the FEU:
    i. Program name(s)
    ii. Markets addressed (residential, commercial, industrial and also by retrofit vs. lost opportunity)
    iii. Incentive budget
    iv. Non-incentive budget
    v. Annual and cumulative energy savings

Response:

The following chart provides information for existing programs offered solely by the FEU including program name, markets addressed, budget and forecasted energy savings across the EEC program areas.

Existing Programs Offered Solely by the FEU - 2011 Forecast:

Program	Markets Addressed	Budget ($000)		Energy Savings	
		Incentive	Non-Incentive	Annual (GJ/yr)	NPV (GJ)
Furnace Service "TLC" - 2011	Residential Retrofit	460	146	No direct savings	
Domestic Hot Water Heaters	Residential Retrofit	536	172	7,152	59,458
EnerChoice Fireplace - 2011	Residential Retrofit	720	146	14,136	127,994
Efficient Boiler Program	Commercial New Construction / Retrofit	1,625	35	50,911	535,500
Light Commercial ENERGYSTAR® Boiler Program	Commercial New Construction / Retrofit	199	13	13,509	141,803
Efficient Commercial Water Heater Program	Commercial New Construction / Retrofit	116	13	4,504	46,058
Energy Assessment Program	Commercial Retrofit	90	29	23,726	23,726
Commercial NGV Demonstration Program	Original Equipment Manufacturer Vehicles	3,780	1	(228,131)	(1,376,306)
Energy Audit Funding Program	Industrial Customers	200	3.0	N/A	N/A

191.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendices K-1, K-3, K-4

General Question

191.1 Please provide a working Excel spreadsheet that provides the information below for each program area (i.e. residential, commercial, enabling activities, etc.):

i. Approved funding and actual or projected spent in 2008 – 2011 for each program area and proposed funding by area for 2012 and 2013.
   a. Breakout spending by Incentive and non-Incentive spending.
ii. Variance between approved and actual spending.
iii. Annual energy savings by program for 2008-2011 and the projected savings for 2012 and 2013.
iv. NPV of energy savings by program for 2008-2011 and the projected savings for 2012 and 2013.
v. TRC for each program area.
vi. The portfolio level TRC for 2008-2013.
vii. SCT, using the parameters requested in the application, for each program area.

<u>Response:</u>

Please refer to Attachment 191.1. 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. Please note that funding was approved at the program area level, not at the individual program level, so Attachment 191.1 deals with program area and portfolio level information. Individual program details such as annual and NPV energy savings as requested for individual programs can be found in Attachment 191.2. Proposed funding by program area for 2012 and 2013 can be found in Table K-2 in Appendix K-1 of the Application (Exhibit B-1).

191.2 Please provide a working Excel spreadsheet that provides the following information for each individual program:

i. Approved funding and actual spent annually in 2008 – 2011 by program and proposed funding by program for 2012 and 2013.
   a. Breakout spending by Incentive and non-Incentive spending. For Non-incentive spending, please show:

i. Program administration costs
ii. Marketing and outreach costs
iii. Evaluation costs
iv. Outside contractor costs
v. Any other non-incentive costs

ii. Annual energy savings by program for 2008-2011 and the projected savings for 2012 and 2013.
iii. NPV of energy savings by program for 2008-2011 and the projected savings for 2012 and 2013.
iv. First year cost of saved energy by program for 2008-2011 and the projected savings for 2012 and 2013.
v. Number of participants in program for 2008-2011 and the projected participants for 2012 and 2013.
vi. Free ridership.
vii. Tonnes greenhouse gas emissions saved.
viii. The TRC and SCT value for each program in 2008-2013.

Response:

Please see Attachment 191.2a for expenditure breakdown by category for individual programs as requested in point (i) of BCUC IR 1.191.2..

Attachment 191.2.b provides individual program details, and addresses the information requested in points (ii)-(viii) of this information request, with the exception of point (iv), which is addressed below. Funding was approved by the Commission at the program area level, not at the individual program level, therefore "approved" vs "actual" funding at the individual program level cannot be provided. "Approved" vs. "actual" program area funding information is provided in Attachment 191.1 in response to BCUC IR 1.191.1. Detailed program design for 2012 and 2013 has not yet been completed, so the Companies are not able to provide detailed information for these years at this time. Program details for 2012 and 2013 will be developed over the course of 2011, and will be presented to the EEC Stakeholder group for their feedback in November 2011.

In the Company's respectful view, the first year cost of saved energy by program requested in point (iv) is not relevant and therefore has not been provided. The first year cost of saved energy is determined by dividing the savings in year 1 by the total costs incurred in the first year. These costs include the all the program development and launch costs incurred in bringing a program to market as well as the incentives incurred in the first year. As such, this can be a very misleading metric. Different programs, which may have the same TRC or SCT will have very different ratios by this metric as the first year cost of saved energy metric is skewed by factors such as program life, the relationship of advertising and promotion expenses (which tend to be front end loaded) to incentives, etc. As such, the FEU rely on lifecycle metrics and it is inappropriate to rely on "first year" metrics.

191.3 Which of the programs under the FEU EEC existing and proposed portfolios are demand side measures as defined by the *Utilities Commission Act*?

Response:

The *Utilities Commission Act* refers to the definition of demand-side measure in the *Clean Energy Act,* which defines demand side measures as:

"a rate, measure, action or program undertaken

a) to conserve energy or promote energy efficiency

b) to reduce the energy demand a public utility must serve

c) to shift the use of energy to periods of lower demand

d) but does not include

e) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increasegreenhouse gas emissions in British Columbia, or

f) any rate, measure, action or program prescribed;"

As such, all of the programs in the FEU EEC existing and proposed portfolios are demand side measures, since they all conform with one or more of (a) to (c) above.

191.4 For the years 1991-2013, please provide a table and a graph showing the FEU's total EEC spending/year and total GJ/year saved.

Response:

The tables and graphs below illustrate the EEC program spending and annual savings from 2002 to 2011. Table 1 includes both program spending and volume impacts from NGV; Table 2 shows program spending and volume impacts excluding NGV, and is more representative of the correlation between program spending and energy savings as it does not include load increases from NGV in 2010 and 2011. The material provided below is from the Companies' Annual Reviews and EEC Annual Reports.

The FEU do not have data available from the period prior to 2002. A consistent methodology for reporting energy savings for DSM activity was implemented in 2006; therefore, the numbers from the years prior to 2006 should be considered less reliable than the numbers from 2006 on. It appears that the energy savings for 2002 and 2003 were achieved with relatively low levels of DSM expenditure; however the energy savings numbers for the years 2002 and 2003 include very significant savings contributions from the Residential Heating System Tune-up and the Heating System Upgrade programs. The Companies have been unable to verify the savings figures included in the Companies' Annual Reviews for 2002 and 2003. The Annual Review for 2002 notes that the savings from the Residential Heating System Tune-up were unable to be confirmed due to insufficient data. It can be seen in Table 2 that from the period 2008 on there has been a steady and consistent upward trend in both EEC expenditure and energy savings.

Table 1: Program Spending and Volume Impacts from NGV

	DSM Spend & Savings with NGV programs									
	Actuals									projected
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Annual Gross Savings(GJ)	230,000	170,000	80,000	186,560	188,508	173,000	88,766	185,484	71,429	59,292
Annual DSM Spend($000)	1,569	1,654	1,904	891	438	1,578	4,274	6,072	17,702	26,900

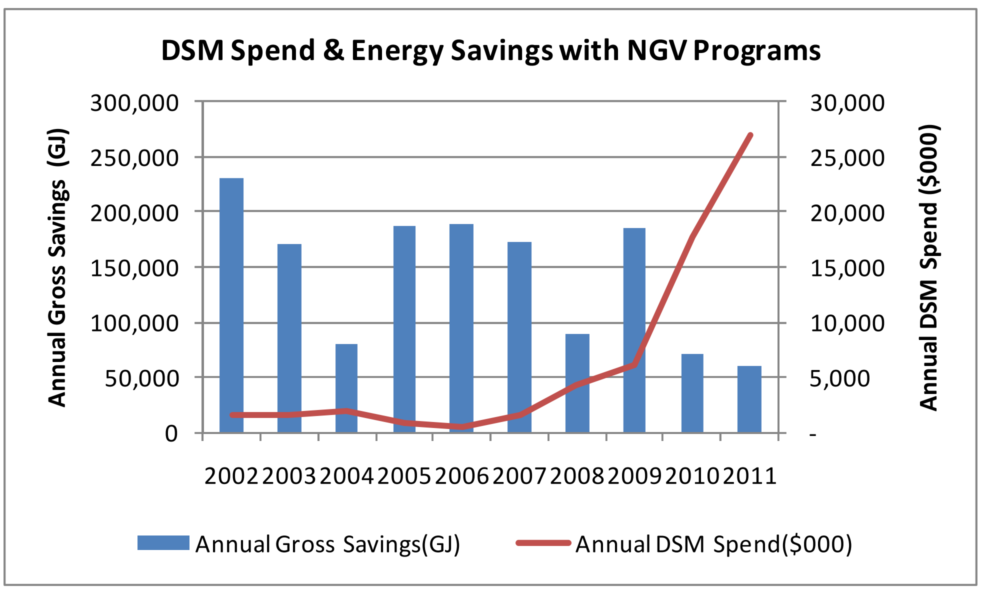
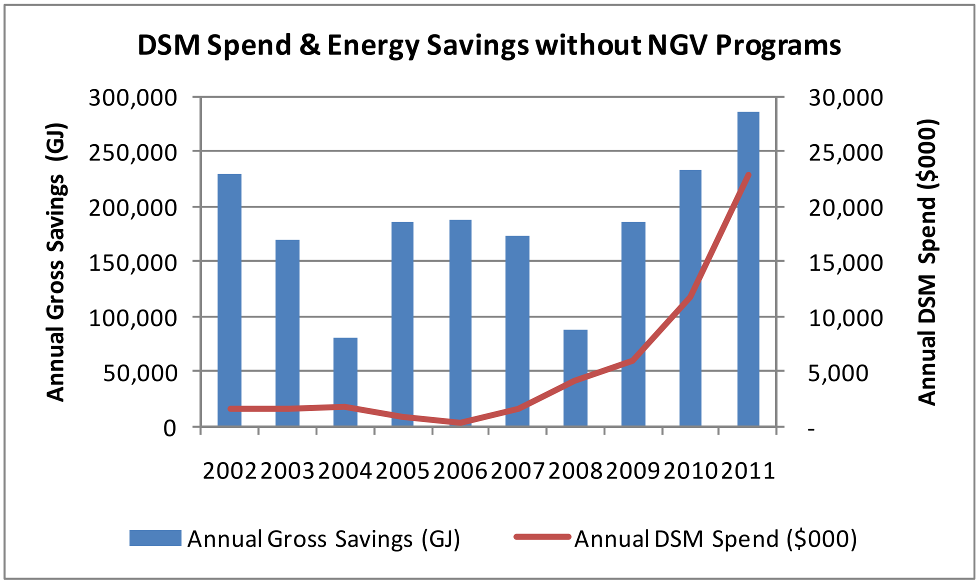


Table 2: Program Spending and Volume Impacts Excluding NGV

	DSM Spend & Savings without NGV programs									
	Actuals									projected
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Annual Gross Savings (GJ)	230,000	170,000	80,000	186,560	188,508	173,000	88,766	185,484	232,657	285,220
Annual DSM Spend ($000)	1,569	1,654	1,904	891	438	1,578	4,274	6,072	11,738	22,845

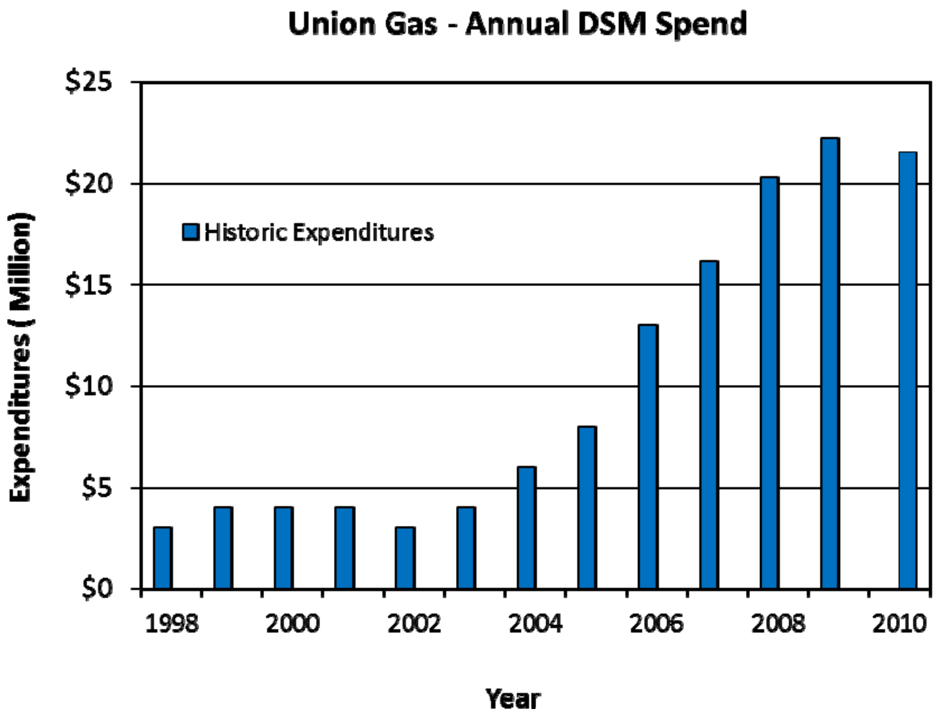


191.4.1 For the years 1997-2011 please provide a table and a graph showing Enbridge Gas's and Union Gas's total DSM spending/year and total GJ/year saved.

Response:

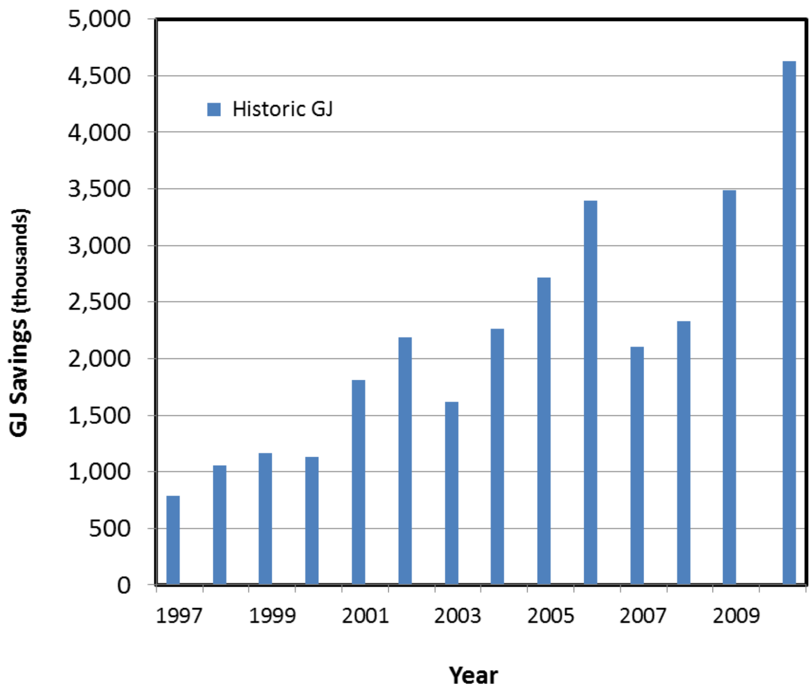
The data for the following charts has been obtained by establishing contact with the relevant DSM representatives of Union Gas & Enbridge respectively. As noted in the response to BCUC IR 1.192.4.2, the conditions in which utilities operate varies across the country. Therefore the DSM expenditures for utilities in Ontario will be different from the levels of expenditure that will be established for the FEU, which operates in British Columbia.

The following charts illustrate **Union Gas'** total DSM spending and savings in GJ, with data only being available for the years 1998 to 2010.



Data for 2010 is pre-audit expenditure

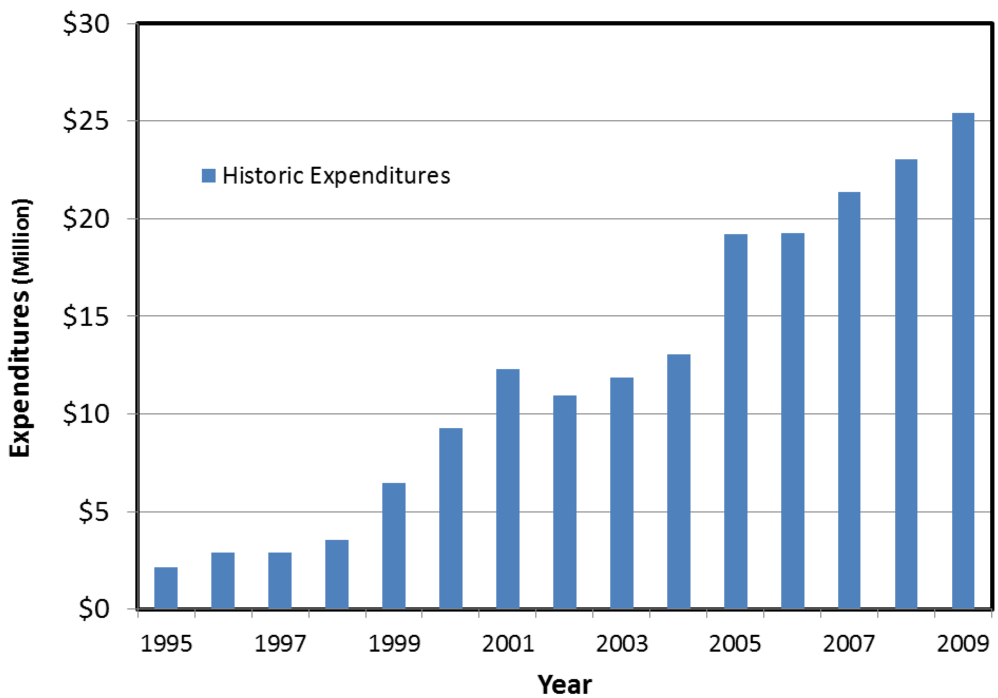
Union Gas - Annual DSM Natural Gas Savings



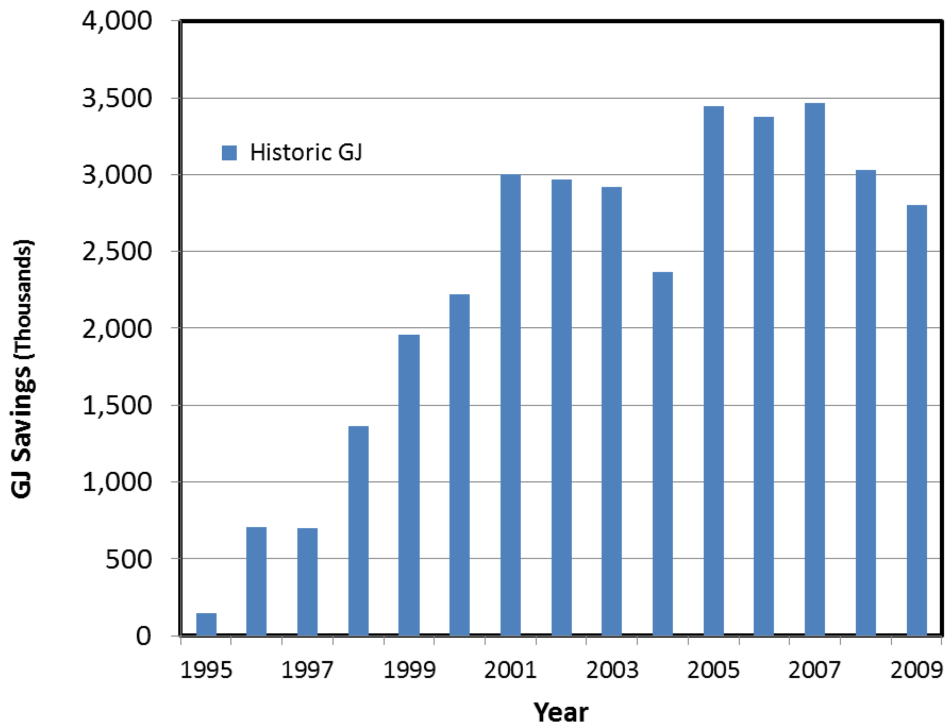
Data for 2010 is pre-audit.

The following charts illustrate the Annual DSM spend and savings for **Enbridge Gas**, with data only available for 1995 to 2009. 2010 is not currently available as the audit of Enbridge's 2010 DSM results is currently in the progress, and expect that this will be filed with the Ontario Energy Board, sometime in Q3.

Enbridge Gas - Annual DSM Spend



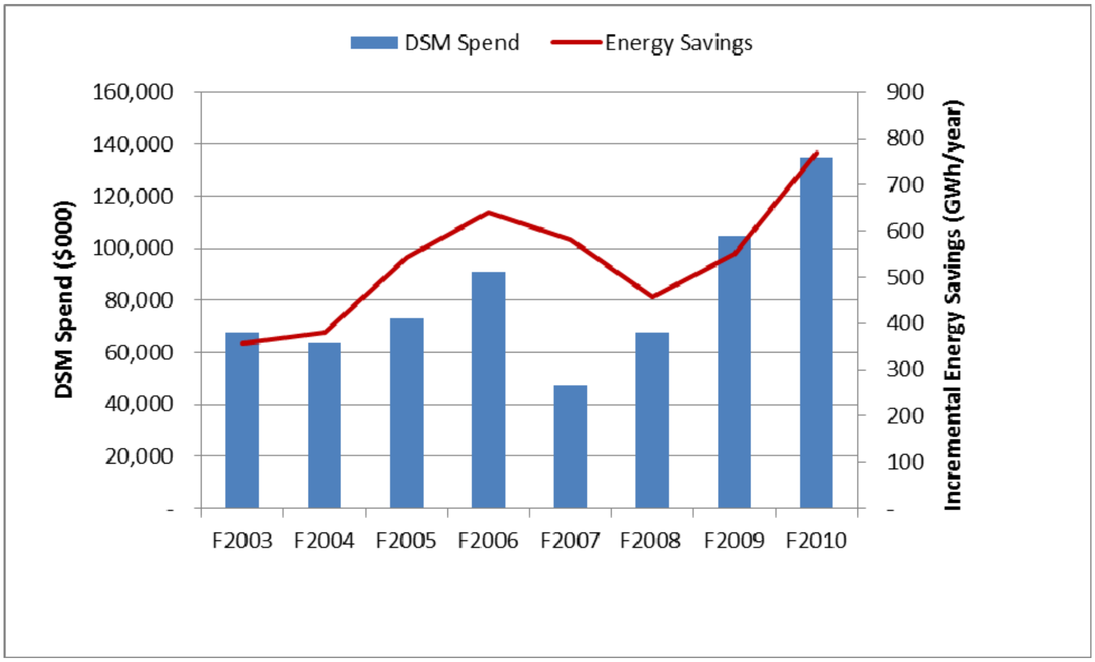
Enbridge Gas – Annual DSM Natural Gas Savings



191.4.2 For the years 1991-2011, please provide a table and a graph showing BC Hydro's total DSM spending/year and total GWh/year saved.

Response:

The following chart illustrates the annual savings in GWh /year saved and BC Hydro's total DSM spending since 2003. The Companies were not able to readily obtain information about the period 1991-2003.



DSM Spend
Energy Savings
DSM Spend ($000)
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
900
800
700
600
500
400
300
200
100
-
Incremental Energy Savings (GWh/year)
F2003
F2004
F2005
F2006
F2007
F2008
F2009
F2010

192.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, Table K-2, p. 3, and Part 1.2.2, p. 11

Enhanced Energy Efficiency and Conservation Programs

"…total funding for EEC activities to $31.0 million in 2010 and $35.3 million in 2011. Of this approved expenditure, FEU spent $12.6 million in 2010 and is projecting to spend $25.7 million in 2011." (Part 1.2.2, p. 11)

192.1 Why did the FEU not spend to the approved expenditure levels in 2010 and 2011?

Response:

It should be noted that the information referenced above for 2011 is a projection, not an actual figure.

The Companies received approval for an increase in EEC activity in May 2009, and current expenditure levels were approved in late November 2009, relatively recently. The approval received in the 2010/2011 Revenue Requirements Application increased the total amount of DSM funding available from approximately $4.5 million annually for the Mainland and Vancouver Island service territories prior to May 2009 only $31.0 million to 2010 and $35.3 million in 2011. The Companies added human resources over the summer of 2009, and again in the late spring/summer of 2010 in order to develop, design and implement the additional programs and initiatives made possible by the increase in EEC funding. Due to the fact that EEC expertise is a fairly rare commodity in the marketplace, it took a significant amount of time to train the new staff, only one of whom had prior EEC program experience, on the natural gas distribution business and on EEC. This delayed the development and deployment of new programs. Further delaying work on new programs was the considerable amount of EEC staff time spent from mid-December to the end of March of both 2010 and 2011 on completing the 2009 and 2010 Annual Reports. The Companies are currently in the process of increasing the staffing levels within the EEC group again, as the FEU have recognized that current staffing levels are not adequate to develop and deploy all of the potential programs made possible by the increased approved expenditure levels.

Another key factor in the Companies not spending to approved levels was the economic downturn, and a degree of uncertainty within the marketplace created by changes in government programs. The following material is excerpted from Page 8 of Appendix K-4 of the Application (Exhibit B-1).

"First, both the financial crisis and the changes in provincial government leadership impacted the customers' focus on EEC activities. The financial crisis that started in 2007 continued to affect the economy in British Columbia in 2010. The Companies' commercial customers were constrained by tighter access to credit, and since the customers' focus was on keeping their businesses going during challenging times, it was more difficult to get them to spend more of their already constrained funds on energy efficiency and conservation. For residential customers, concerns about the impact on their employment from the economic challenges the country was facing, together with the end of the federal Home Renovation Tax Credit, had reduced customer activity in this program area. Moreover, uncertainty about the direction of the provincial government resulting from the changes in the Liberal and NDP leaderships also negatively impacted customer focus on EEC by increasing customer uncertainty about the longevity of government programs such as LiveSmartBC."

A third factor in the underspend was the relatively low cost of gas; it is more difficult to get the attention of customers focussed on energy efficiency and conservation when the commodity portion of their natural gas rate is $4.568/GJ. The material below is excerpted from page 9 of Appendix K-4 of the Application (Exhibit B-1).

"With the current climate of low natural gas prices, the price of natural gas cannot be considered a driver of energy efficiency upgrades to any great extent, except in those customers with very high gas consumption or where natural gas is a significant input into some business process. Although the current price of gas can make it a challenge to find cost effective energy saving measures to incent, it reinforces the need for energy efficiency programs in order to achieve the government's energy and climate change objectives. With low natural gas prices, some customers are not motivated to save without utility encouragement. Energy Efficiency and Conservation programs then become necessary to drive long term market transformation towards improved efficiency."

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.

192.2 Why is such a large increase in funding necessary in 2012 and 2013 given that actual expenditures in 2010 and 2011 are significantly below budget?

Response:

Please see also the response to BCUC IRs 1.192.1 and 1.196.4. During 2010 and 2011, EEC activities are in the process of ramping up from a relatively low level of expenditure in 2009. 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. Individually, the increases for each area of previously approved activity are generally relatively modest, and that in the case of the Commercial program area, no increase has been budgeted. The increase requested funding for "conventional" EEC activity is from $29.675 million to $38 million per year. There is an increase in overall Innovative Technologies funding from $5.625 million to $11 million per year; the largest part of this increase is comprised of the Commercial NGV purchase incentive which is budgeted at $10 million per year, while non-NGV Innovative Technologies initiatives are budgeted at $1.5 million per year. 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. The significant increase in funding requested is largely for these "New Initiatives", expenditure and activity specific to which was largely not contemplated in the previously established programming and budgets.

192.3 In the Application FEU proposes to expand EEC programs to the Whistler service area. Why is FEU not expanding its EEC programs to the Fort Nelson service area?

Response:

The exclusion of Fort Nelson in the wording of the Application was an oversight. It has always been the FEU's intention to expand EEC programs to the Fort Nelson service area, and, like Whistler, the proposed adjustment to the EEC deferral account mechanism will enable the FEU to offer programs to our Fort Nelson customers in 2012 and 2013. As discussed in the response to BCUC IR 1.104.2, all EEC incentive costs will be tracked on an as spent basis by utility. Therefore, in the forecast period, the FEU will have the means to track EEC costs applicable to Fort Nelson customers in a non-rate base deferral account for future recovery from Fort Nelson customers.

192.4 Please complete the table below which is similar to Table 3.5 – Summary of Information Other Utilities DSM Activity submitted in the May 28, 2008 Energy Efficiency and Conservation Programs Application. Please provide a summary of FEU and comparable utilities in both Canada and the United States.

Company Name	Utility Type	2010 DSM Annual Budget	Start DSM Year	DSM Funding Treatment	Company Earns on DSM	Customer Base	F/T DSM Employees	Total Employees	2010 Asset Base	2010 Total Revenues	% Spent on DSM of Revenue	DSM Spend per customer	$/energy saved (total DSM spend/total GJs or GWh saved)	2010 Annual Sales Volume (PJs)

Response:

Please refer to the following table for a summary of the FEU and other utilities.

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)
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
FortisBC Electric	Electric	3.95	1989	DSM costs are treated as capital and amortized over fixed time period.	Yes	161,019	9.4	549	975.1	257	1.54%	24.53	0.10	40.64	10.96
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
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
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
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
Gaz Metro	Natural gas	12.219	1999	As O&M	Yes	179,370	9	1,320	3600	2,250	0.54%	68.12	1.22	10.04	209.26
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
SaskEnergy	Natural gas	1.07	2001	As O&M	No	352,000	9	1,100	1600	952	0.11%	3.04	0.21	5.14	146
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
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
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	8.81	3,320	0.60%	11.37	0.12	170.48	214.4
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

192.4.1 Please provide the amortization periods for companies where DSM costs are treated as capital and amortized over a fixed period of time (not limited to companies FEU includes in their response to the IR above).

Response:

The FEU were able to find the following utilities that treat DSM costs as capital.

Company	**Treatment of DSM funding**
FortisBC Energy	DSM costs are treated as capital and amortized over a 10 year period
FortisBC Electric	DSM costs are treated as capital and amortized over a 10 year period
BC Hydro	DSM costs are treated as capital and amortized over a 10 year period
Manitoba Hydro	DSM costs are treated as capital and amortized over a 5 year period for gas DSM, and a 10 year period for electric DSM. The policy of treating DSM costs as capital is being reviewed and therefore could change.
NW Natural	DSM costs are treated as capital and amortized over the estimated measure lifetime using a discount rate. Typically measures are at least 20 years.

192.4.2 Please discuss the difference in $/GJ saved between the FEU and other natural gas utilities.

Response:

The apparent difference in $/GJ saved arises due to two reasons:

First, the utilities included in the survey all report DSM budgets and energy savings differently. Some may report gross energy savings; some may have free riders netted out; some may incorporate spillover effects. Expenditures that are included in reported DSM budgets will also vary significantly from utility to utility. The FEU, at this time, have not conducted research to find out exactly what expenditures are included in DSM budgets, and what kind of savings number is being reported, and such research would be challenging to undertake. Thus an "apples-to-apples" comparison of DSM budgets and resultant energy savings is very challenging.

Second, all the utilities surveyed operate in different climates, building envelopes and political environments. This fact means that the kinds of programs that drive expenditures that make up DSM budgets, and the energy savings associated with those programs vary from utility to utility.

For example, the energy savings available to a customer from a building envelope upgrade in Ontario, where winters are colder and longer than they are in British Columbia, would be greater than the energy savings available to a customer of the FEU in, for example, the Okanagan. That does not mean, however, that upgrading a building envelope does not have merit in British Columbia. The political environment in BC, where a significant emphasis is being placed by policy makers on GHG emission reductions, means that such an upgrade would support government policy. Further, the types of buildings, especially in the residential sector, also vary significantly from utility to utility. The materials used in home construction in Southern California Gas' service territory are quite different from the materials used to build homes in, for example, Prince George, and this then affects total home energy consumption, the types of programs implemented by different utilities and the energy savings generated by those programs.

192.4.3 Please comment on the measurement and verification methodology other companies undertake to verify their GJ savings.

Response:

Measurement and verification methodologies that other utilities undertake depend on many factors including the type of program (e.g. heating system upgrade or efficient boiler program), sector (residential, commercial ,industrial), level of maturity of the program offering, availability of data and individual DSM goals and objectives.

Generally speaking, billing analyses and onsite before and after metering are the two most common methods for getting gross savings estimates from installed energy efficiency measures. Billing analyses are often used for residential and small business programs for scenarios where there are a large number of participants per year and estimating savings from multiple measures is too expensive to evaluate individually to determine savings. For example, billing analyses are often used for calculating savings from a residential home retrofit program which may include weatherization, wall and ceiling insulation measures. Billing analysis is best applied for scenarios where estimating savings from each measure would be extremely difficult and/or expensive so looking at the savings as a bundle is the more reasonable and economical approach. Onsite before and after metering is often used for large commercial and industrial installations of efficiency equipment. For more common measures such as efficient boiler programs, the equipment for a statistically valid sample of customers may be monitored for savings. The results are then applied on a per fixture basis to all other installations. For more complex measures such as chillers and industrial equipment or even for pilot demonstration projects such as solar thermal, each installation may be monitored using devices such as data loggers to estimate savings on a real time basis. Many variations exist on the above on a program by program basis.

It should be noted that savings estimated through such analysis as mentioned above assumes that the customer continues to operate their systems in the same manner as before and this may not always be the case. For instance the number of occupants may change over time in a household, changes in business operations due to economic cycles for commercial and industrial customers. For this reason, the FEU believe as a best practice it is prudent to conduct implementation surveys, and interviews at regular intervals to audit the measure and incorporate changes.

Please refer to Attachment 192.4.3 which contains a report from the North East Energy Efficiency Partnerships which outlines methods and savings assumptions guidelines on a program by program basis. FEU applies best practices by adopting principles from such research and by discussions with other utilities.

192.4.4 What are the 2012 and 2013 DSM expenditure levels of the other natural gas utilities listed in the table and, specifically, for other natural gas utilities in Canada?

Response:

The current position of Canadian natural gas utilities' 2012 and 2013 budgets is shown below.

Ontario Gas Utilities

The natural gas utilities in Ontario including Union and Enbridge currently do not have DSM plans for 2012 and beyond. The Ontario Energy Board in consultation with stakeholders is reviewing the existing DSM framework and guidelines for the natural gas distributors. The outcome of the review will guide the utilities in developing their DSM plans (expenditure budgets and savings targets) for 2012 and beyond.

ATCO Gas

ATCO Gas does not have DSM budgets for 2012 and 2013. Its DSM services to date have been primarily focused on education and outreach programs. ATCO Gas does not currently have a mandate to deliver DSM services from the Province or regulator.

GazMetro

DSM Budgets

2012	$12.493 Million
2013	$12.256 Million

Manitoba Hydro

DSM Budgets

2011/2012	$11.8 Million
2012/2013	$11.9 Million

SaskEnergy

2012 and 2013 budgets have yet to be approved by their regulator.

192.5 Please complete the following table showing a historical comparison of the FEU's EEC activities:

		1	2	3	4	5
		2008	2009	2010	2011	2012
1	Total DSM Spend					
2	DSM spend/customer (based on total utility customers)					
3	$/GJ saved (Total DSM spend/Total GJ saved)					
4	DSM spend/total utility revenue					
5	DSM spend/margin					
6	DSM evaluation costs					

Response:

The table below shows the historical comparison of the FEU's EEC activities.

	1	2	3	4	5
	2008	2009	2010	2011	2012
Total DSM Spend	$4,274,000	$ 6,072,000	$ 17,702,000	$ 26,900,000	n/a
Total DSM Spend (excluding load building)	$4,274,000	$ 6,072,000	$ 11,811,000	$ 23,295,000	n/a
DSM spend/Customer (based on total utility customers)	$5	$6	$19	$28	n/a
$/GJ saved (Total DSM spend excluding Load Building/Total GJ saved)	$7	$5	$8	$10	n/a
DSM spend/Total utility revenue	0.2%	0.4%	1.1%	1.9%	n/a
DSM spend/margin	0.7%	0.9%	2.6%	4.0%	n/a
DSM evaluation costs	$205,000	$12,000	$123,000	$406,000	n/a

Please note that 2011 figures are projections only. The Companies have seen steadily increasing activity over the time period as EEC activity has ramped up, program activity has been expanded and more customers have participated in more programs. DSM expenditures per customer have increased over time, as the Government of British Columbia has placed an increasing focus on DSM as a key component of its greenhouse gas emission reduction strategy.

193.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 3-4

Requested Funding Envelope for 2012 and 2013

193.1 The FEU request permission to include actual expenses above $20 million (up to $74.5 million) to be recorded in "non-rate base" deferral account (attracting AFUDC). Such accumulated funds would be recoverable in rates starting in 2014.

193.1.1 Will AFUDC earned on the energy efficiency deferral account be deferred until 2014? If deferred, has the amount of deferred returns on the outstanding balance been included as a cost to the proposed 2012 – 2013 programs under the TRC? Under the SCT test?

Response:

From a customer perspective, any AFUDC earned on the non-rate base deferral account will not be included in cost of service, and will thereby be deferred, until 2014. As discussed on page 4, Appendix K-1 of the Application (Exhibit B-1), the intent of establishing this non-rate base deferral account is to ensure that customers only pay for actual EEC expenditures that are incurred during 2012 and 2013.

Both the TRC and the SCT tests attempt to establish a benefit-cost analysis through use of a discounted cash flow model. Under the TRC, the discount rate currently being used to evaluate EEC programs is based on the Companies' weighted average cost of capital, whereas under the SCT test, a 3 percent discount rate is being proposed. In both cases the discount rate is being employed as a means to re-state future benefits and costs back to net present value.

Insofar as the Companies weighted average cost of capital is used to calculate AFUDC and as a discount rate in the TRC, the full amount of AFUDC deferred is being recognized under the TRC test.

Under the SCT test, any deferred AFUDC is being included to the extent of the 3 percent discount rate.

193.2 Please provide in Excel format, forecasted revenue requirements associated with the energy efficiency deferral account for the period 2014 -2020. Please include the following components by year:

i. Beginning balance
ii. Amortization amount
iii. Ending balance
iv. Earned return using ½ year convention
v. Amount to be included in revenue requirement (if different than item iv above)
vi. Incremental rate impact by customer class (provide detailed explanation/algorithms of calculations)

Response:

Please refer to Attachment 193.2, which is a fully functioning Excel spreadsheet.

Please note that this analysis may not be representative of the actual balance in the EEC account and the corresponding revenue requirement and rate impacts for each Utility, for the 2014-2020 forecast periods. To complete this analysis, the FEU have made the simplifying assumption that the maximum amount of funding ($54.5 million) will be captured in the non-rate base EEC account and has allocated this funding based on average customers. The FEU have also assumed that the balance in this account will be transferred to rate base effective January 1, 2014. The actual additions to the non-rate base account will occur on an as spent basis and will be tracked by utility and amortization of the balance in the non-rate base deferral account will be addressed in a subsequent revenue requirement application.

193.3 Does the FEU consider the proposed rate of return on the proposed energy efficiency deferral account a form of incentive to pursue all cost effective demand side management and energy efficiency?

Response:

The use of the word "Incentive" in the non-rate base EEC deferral account name is in reference to the type of EEC costs that are expected to make up the majority of the balance in the account. It is not meant to indicate that it provides an incentive to the Companies. Earning the Companies' regulated rate of return on EEC expenditures, however, does put an EEC investment on the same footing as any other investment in the utility, and absent any restrictions to capital investments would encourage the utility to purchase all cost-effective EEC opportunities. This matter was addressed at some length during the original EEC proceeding in 2008/2009. See, for example, the response to BCUC IR 1.43.2.4 series, BCUC IR 1.65.1 (2008

EEC Application, Exhibit B-2) and the BCUC IR 2.29 series (2008 EEC Application, Exhibit B-3) in that proceeding, which are provided in Attachment 193.3.

Please see also the response to BCUC IR 1.193.4.

193.4 Has the FEU considered other forms of performance incentives to achieve all cost effective demand side management and energy efficiency? If so, please provide detailed descriptions of each performance incentive model the Companies researched and considered.

<u>Response:</u>

The FEU provided discussion of its views on other forms of performance incentives in achieving all cost effective demand side management and energy efficiency in the 2008 EEC Application in the responses to BCUC IRs 2.29.1 to 2.29.6. Please also refer to the response to BCUC IR 1.193.3 and Attachment 193.3. The responses to the BCUC IR 2.29 indicate that the approach proposed in the EEC Application (and approved by BCUC Order No. G-36-09) of deferring EEC expenditures, including them in rate base and amortizing the deferred EEC expenditures in rates over a number of years provided an adequate and appropriate incentive to pursue all cost-effective EEC. This approach provides the FEU with the same fair return for investing in EEC as is received for investing in new gas infrastructure to accommodate load growth. The 2008 EEC IR responses also indicate that the accounting treatment proposed by the Companies to allow the FEU to earn a return on the EEC expenditures is consistent with Section 60(b)(ii) of the *Utilities Commission Act* that states:

> *"Provides to the public utility for which the rates is set a fair and reasonable return on any expenditure made by it to reduce energy demands"*

In the 2008 EEC Application IR responses the FEU opposed approaches that were based on treating EEC expenditures as current period expenses and provided an incentive to the Companies based on exceeding performance targets. It was argued that approaches of this type did not provide an adequate opportunity to earn a fair and reasonable return on EEC expenditures and were not therefore consistent with *UCA* Section 60 (b) (ii). The FEU indicated (in 2008 EEC BCUC IRs 2.29.3 and 2.29.4) that they would be open to considering an incentive based proposal that added performance based incentives on to a model that already included rate base treatment of EEC expenditures, fair return and amortization in rates.

The FEU continue to hold the views expressed in the 2008 EEC Application IR responses included in Attachment 193.3 is the response to BCUC IR 1.93.3 above. In addition the proposal in this Application to change the EEC benefit / cost test to the Societal Cost Test will, if approved allow a greater number of EEC programs to go ahead.

194.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 7

EEC Funding for Conventional EEC Activity

"An increase in budgeted funding for high-carbon fuel switching to lower carbon fuels (e.g. Heating oil to natural gas) from approximately $1.5 million to $2 million. This activity would be aimed at residential and commercial customers, and would have the goal of moving these customers off propane and heating oil, and onto natural gas. It could also be aimed at moving customers onto alternative forms of energy, such as geoexchange with natural gas backup. This funding does not include fuel switching from electricity to natural gas."

194.1 Will this program be exclusively for residential and commercial customers?

Response:

This initiative would be for residential, commercial and potentially for large institutional customers, such as geoexchange systems for hospitals or universities.

194.2 Does the FEU consider fuel switching programs to be load building activities? If not, why not. If yes, is the TRC the appropriate cost effectiveness screen for this program?

Response:

The TRC is an appropriate cost-effectiveness screen for high-carbon fuel-switching programs. The California Standard Practice Manual ("CSPM") states (at p. 2):

"Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building)".

For example, supplying natural gas buses to areas that previously did not have any buses is "load building," but displacing diesel buses with natural gas buses is "fuel switching." The CSPM states that the TRC test (and by extension SCT, which is a modified TRC) *"is applicable* *to conservation, load management, and fuel substitution programs"*. Moreover, the application of the TRC or SCT test to the NGV program properly assesses the cost-effectiveness of the program. The Commission accepted the use of the TRC test for the Innovative Technologies program area in its 2009 EEC Decision and this treatment was continued in the approved 2010-11 NSAs for FEI and FEVI.

While the type of fuel-switching programs referenced in the quote, where customers are moved from higher-carbon fuels such as propane and heating oil to natural gas, do increase load on the FEU's system, they also reduce greenhouse gas emission in an economic manner by the improved efficiency of the equipment at the end use application. In other fuel switching programs, like NGV programs, covered under the Innovative Technologies portion of the EEC budget, the FEU consider the load building aspect to be an important contributor of value to the FEU's customers in the face of declining core market load. The added load from NGV programs also improves overall system efficiency by adding year-round load while the core market declines have load reductions that are mainly in the high usage winter period. The goals of the FEU's high-carbon fuel-switching programs are to reduce green house gas (GHG) emissions and improve overall energy efficiency. Fuel-switching for the purpose of efficiency should not be confused with load building and the California Standard Practice Manual[28] has long recognized the importance of fuel-blind efficiency by expanding tests to include all fuels.

The high-carbon fuel switching programs will achieve significant GHG emission reductions for customers who switch from heating oil or propane to natural gas. While CO_2 emissions associated with natural gas are 117 pounds per million BTU, compared to 161.29 and 137.34 per million BTU for heating oil and propane, respectively[29]. This will result in savings of nearly 30 percent for heating oil conversions and 14 percent for propane conversions for CO_2 alone.

In addition, the incentives for this program will be designed to encourage equipment and system energy efficiency. The Companies' Switch and Shrink program, for example, offers customers an incentive of $1,000 for switching from oil or propane to natural gas, but stipulates that the customer MUST purchase an Energy Star furnace or boiler. In many jurisdictions, customers can receive rebates for fuel-switching separately from energy efficiency incentives. For example, Consolidated Edison of New York offers customers up to $2,000 to switch from oil to natural gas. An additional, but separate, rebate of up to $1,000 is available for purchasing energy efficient boilers or furnaces. Similarly, Puget Sound Energy offers conversion rebates up to $3,950 in addition to separate rebates for equipment efficiency.

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[28] California Public Utilities Commission (CPUC). 2001. California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects. Sacramento, CA: Governor's Office of Planning and Research, State of California.

[29] U.S. Environmental Protection Agency. 2011. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

The importance of GHG emission reductions, the benefits of which accrue to society as a whole, suggests that the most appropriate test for this program is the Societal Cost Test (SCT). The FEU believe the SCT is the correct test for evaluating the cost-effectiveness of this program. The practice to date in assessing all EEC programs has been to apply the TRC test.

195.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 8

EEC Funding for Conventional EEC Activity

"In 2010, the Companies committed approximately $12.1 million in EEC funding to non-NGV EEC activity aimed at the Companies' Residential, Commercial and Industrial customers, for annual energy savings of 166,110 GJ/year."

195.1 Is the 166,110 GJ/year in energy savings a projected amount or has it been verified through measurement and verification methods?

Response:

The savings of 166,110 GJ/year is an estimated amount. The savings has been estimated on a program by program basis by multiplying the number of expected participants with the estimated savings, with an adjustment to create a net to gross ratio. For some of the established programs such as the heating system upgrade or the commercial energy assessment program where the savings have been evaluated by a third party consultant, the FEU have incorporated those values into the calculations. For the others that are new to the market place and where little historical data is typically available for analysis, the Utilities lean towards adopting the estimated savings other utilities incorporate into their DSM program analyses. Through a combination of informal discussions with consultants and/or other industry experts and the Utilities' own analysis, the energy savings are estimated during program planning stages.

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.

195.1.1 Have any of the programs' impacts been evaluated by an independent 3rd party evaluator?

Response:

Please see the response to BCUC IR 1.212.1

196.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 8

EEC Funding for Conventional EEC Activity

"The Companies' recently completed Conservation Potential Review, the Summary for which is attached as Appendix K-2, found that the Most Likely Achievable Potential energy savings in the Residential, Commercial and Industrial areas of activity were 2.2 million GJ/year by 2015, and 10.3 million GJ/year by 2030…While the Companies are relatively new to this scale of EEC expenditure and activity, and the funds committed in 2010 included some 'one-time' costs such as a DSM tracking system, it can be seen that in order to achieve the energy savings found to be available in the CPR, higher expenditures will be necessary."

196.1 In its 2012-2013 EEC plan, is the FEU aiming to achieve the most likely Achievable Potential scenario or the aggressive Achievable Potential scenario from the CPR?

Response:

Neither; it must be noted that a Conservation Potential Review and an EEC plan are two quite different items. The EEC plan for 2012 and 2013 has not yet been developed, but will be based on the 2010 and 2011 activity, with the addition of any approved activity in New Initiatives. A Conservation Potential Review is a high level planning document that can be used as the basis for the development of an EEC plan. A CPR is directional in nature, and points to some potential areas of EEC activity that can be incorporated into an EEC plan, which would then have projected energy savings associated with it. The outcomes of the Companies' recently completed CPR, provided in Attachment 196.1, show that there are indeed energy savings available, and an EEC plan for 2012 and 2013 will be developed in order to capture some of the savings identified in the CPR.

196.2 Please provide an itemized list of one-time expenses incurred in 2010 and a summary description of the asset/service placed in service.

Response:

The one-time expenses of a significant size that were incurred in 2010 were approximately $645,000 for the DSM tracking system, described in Section 14.2 of Appendix K-4 of the

Application (Exhibit B-1), and approximately $314,000 toward the Conservation Potential Review, the Summary Report for which is attached as Appendix K-2.

196.3 Please provide a summary description of the reporting capabilities of the DSM tracking system. Included in your description, please discuss whether Fortis' DSM tracking system will be integrated with the data tracking systems associated with the LiveSmartBC programs or any other jointly offered program.

Response:

DSM Tracking System Summary Description:

Reporting for the DSMS will consist of a standard reporting tool with ad-hoc reporting capabilities. The standard reports shall consist of the following:

- Monthly Tracking Summary Report: Provides a monthly summary of various attributes that are tracked in the DSMS by EEC Program (or Program Measure).
- Annual DSM Summary Report: Provides a summary of various attributes that are tracked in the DSMS by EEC Program.
- Annual Expenditure Summary Report: Provides a summary of various expenditures that are tracked in the DSMS by EEC Program or Measure.
- Detailed Tracking Reports: Provides a detailed view of monthly or annual information for a particular attribute that is tracked in the DSMS by EEC Program (or Program Measure).
- Detailed Expenditure Reports: Provides a detailed view of monthly or annual information for a particular attribute that is tracked in the DSMS by EEC Program (or Program Measure).

DSMS reporting capabilities include the DSM Test Report which is included under the Detailed Tracking Reports. The DSM Test Report shall detail the DSM test results on an entity level basis and display projected and/or actual DSM test results for the date range selected. The report shall display DSM test results totals (or average) by entity, by date range, and for the total of the entire report.

As part of the standard reporting tool, users will be able to create a report using user-defined criteria or system-defined filters. As a minimum, reports will be created using the following criteria:

- Date Range: Month, Quarterly, Annual, Year-to-Date [YTD], Total from Start
- Reporting Level: Portfolio, Program Area, Program or Program Measure Level
- Data Status Type: Budget, Projected and/or Actual

Reports will conform to the DSM hierarchy requirements such that reports may only be created and generated based on the information within an EEC Portfolio. To generate a report that crosses multiple EEC Portfolios, the user will be required to export the data from multiple portfolios to an external tool. Reporting shall be handled outside of the DSMS.

Further, the selection of a date range for any report shall adhere to the rule that the report can only be generated for a date range that falls within the life span defined for a particular portfolio. That is, the report may only be generated for a particular program or program area that spans within the life of the EEC Portfolio they belong to. The System will not allow the selection of dates outside the portfolio life span or effective date of a program/program measure.

The DSM tracking system will not be *integrated* with program tracking systems for programs that are led by other entities, such as LiveSmartBC, which is led by the provincial government. The DSMS, however, does allow for the import and/or export of data to and from systems external to the FEU.

196.4 Please explain why the FEU is requesting an increase in approved funding from $29.676 million in 2011 to $38 million for conventional EEC programs when the Companies are relatively new to this scale of EEC expenditure and of the funds they did spend, some were one-time costs.

Response:

The $38 million for "conventional" EEC activity for each of 2012 and 2013 should be considered part of the overall funding ceiling of $74.5 million for each year for which the Companies are requesting approval. That is, a funding ceiling over which the Companies will not spend without prior approval. The table below shows the proposed change for each program area. It should be noted that the Residential program area contains the activity previous known as Joint

Initiatives. It can be seen in the table below that individually, the increases for each area of previously approved activity are generally relatively modest, and that in the case of the Commercial program area, no increase has been budgeted. While program planning for 2012 and 2013 has not been completed, high-level reasons for the increase in each program area can be found on page 7 of Appendix K to the Application (Exhibit B-1). Generally speaking, the increases proposed are relatively modest, and are based on expanding the type of program activity being undertaken for 2010 and 2011. This information is excerpted below. Please see also the responses to BCUC IR 1.215 series, where Residential/Joint Initiatives work is discussed in more detail, and the response to BCUC IR 1.216.3, where Conservation Education and Outreach is discussed in more detail.

- Consolidation of "Joint Initiatives" activity with "Residential" as all the activity funded in the Joint Initiatives program area undertaken to date has been for residential customers. Collaborative activity with other utilities and government is taking place in all other program areas; it is not, however, broken out into a separate funding category in these other program areas. It makes sense to align funding for collaborative activity for residential customers within the residential program area.
- An increase in budgeted funding for residential customers from approximately $5.2 million (for Residential and Joint Initiatives activity combined) to $9.5 million. The Companies anticipate that a Residential New Home Construction Program, a Domestic Hot Water Program and participation in such collaborative programs as LiveSmartBC will require a larger budget for EEC activity for residential customers than previously established. Residential customers form the bulk of the Companies' accounts, and programs aimed at these customers are very important in creating the "culture of conservation" that will be needed in order to achieve government's energy objectives.
- An increase in budgeted funding for high-carbon fuel switching to lower carbon fuels (e.g. Heating oil to natural gas) from approximately $1.5 million to $2 million. This activity would be aimed at residential and commercial customers, and would have the goal of moving these customers off propane and heating oil, and onto natural gas. It could also be aimed at moving customers onto alternative forms of energy, such as geoexchange with natural gas backup. This funding does not include fuel switching from electricity to natural gas.
- An increase in budgeted funding for low income customers from $3 million to $5 million. Activity in this particular area has good support from government and stakeholders.
- An increase in budgeted funding for conservation education and outreach from $3.5 million to $5 million as the Companies seek to expand activity around influencing conservation behaviours by British Columbians.

- An increase in budgeted funding for all industrial customers, regardless of whether they are on a firm or an interruptible rate, from $1.875 million to $2 million. This is a relatively new area of activity for the Companies, and it is anticipated that we will need time to gain knowledge and experience in this area, therefore only this modest increase is anticipated over the 2012 and 2013 period.

The Companies anticipate that as the EEC group is sufficiently resourced over the course of 2011, the number of programs in each program area, and the subsequent expenditure associated with each program will continue to grow. The Companies will develop programs within the accountability mechanisms established in the EEC proceeding in 2008-2009 and excerpted on pages 4-5 of Appendix K to the Application (Exhibit B-1) and modified. Approved EEC funds that are not spent are not recovered from customers, so the Companies are of the view that as long as the accountability mechanisms previously approved are adhered to, approval of a funding ceiling is the appropriate approach.

	2011 Budgets ($000's)	2012 Proposed Funding ($000's)	2013 Proposed Funding ($000's)
Previously Approved EEC Activity			
Conventional EEC Activity			
Residential	5,220	9,500	9,500
High Carbon Fuel Switching	1,510	2,000	2,000
Low Income	3,000	5,000	5,000
Commercial	14,532	14,500	14,500
Conservation Education and Outreach	3,538	5,000	5,000
Industrial	1,875	2,000	2,000
Subtotal - Conventional EEC Activity	***29,675***	***38,000***	***38,000***
Subtotal - Innovative Technologies	***5,625***	***11,500***	***11,500***
Subtotal - Previously Approved EEC Activity	***35,300***	***49,500***	***49,500***
New Initiatives 2012 & 2013			
Furnace Scrap-It program		**10,000**	**10,000**
Solar Thermal		**4,000**	**4,000**
TES for Schools		**11,000**	**11,000**
Subtotal - New Initiatives		***25,000***	***25,000***
Total Funding		**74,500**	**74,500**

197.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 8

EEC Funding for Innovative Technologies

"As part of their respective NSAs, the parties agreed that the Innovative Technologies Program Area will be managed by FEI and FEVI as a separate segment of the overall EEC portfolio and have a weighted total resource cost (TRC) of 1.0 or more."

197.1 Do the FEU agree that the TRC is the best test of cost effectiveness for the non-NGV Innovative Technologies Program Area? If not, what other test would be better and why?

Response:

According to the approved Negotiated Settlement Agreements ("NSAs"), for 2010 and 2011, the Innovative Technologies Program Area will be managed by FEI and FEVI as a separate segment of the overall EEC portfolio and have a weighted total resource cost ("TRC") of 1.0 or more. While the FEU agree the TRC is a valuable cost-effectiveness viewpoint to consider, the Societal Cost test (SCT) is the most appropriate test for all programs, including the Innovative Technologies Program Area as requested in the 2012 – 2013 RRA. In this instance the SCT allows for the inclusion of non-energy benefits such as water savings and avoided operation and maintenance costs, which can be substantial with innovative or emerging technologies.

However, as noted in the response to BCUC IR 1.197.3.1, FEU is certainly open to innovative technology programs being exempt form a requirement to pass a cost-effectiveness test. The point of innovative technology programs is to jump start fledgling market-ready technologies with substantial promise of greenhouse gas, energy-efficiency, and other benefits. (See response to 197.2 for more discussion about this topic.) Today's costs for innovative technologies, such as solar thermal hot water heaters, are not representative of costs once the technology is mass produced. Programs that promote innovative technologies play an important role in market transformation. As emerging technologies gain market acceptance, as a result of utility programs jump starting the market, costs for these technologies may decrease dramatically. In addition, this type of program can encourage innovation and thereby increase the longevity of portfolio savings. In designing programs, it is important to test the viability of newer technologies before including them in the non-innovative technology general EEC offerings. Innovative technology programs test the savings and customer acceptance of newer technologies while also lining up technologies for future sources of savings within the larger non-innovative technologies EEC portfolio. Market transformation and portfolio longevity have substantial, if difficult to quantify, societal benefits.

The important role of these programs in portfolio longevity is illustrated by the Black Hills Energy (BHE) Residential Innovative Space and Water Heat Technologies programs. The program is designed to encourage the adoption of more recent-to-market technologies and to ensure the energy-efficiency portfolio does not miss opportunities for savings. Both tankless water heaters and mini boilers have transitioned from the innovative program to the standard heating and water heating program in BHE's Iowa portfolio. As part of its innovative technology programs, Black Hills currently offers rebates for drain water heat recovery, multi-zone thermostats, and integrated space and water heating. Incorporating innovative technologies in their portfolio provides the opportunity to easily incorporate these technologies as standard offerings as the market transforms, while taking advantage of the substantial savings associated with these measures.

In evaluating the cost-effectiveness of BHE's program, Iowa and Colorado rely on a Societal Test that includes a benefits adder. Colorado[30] uses a 5 percent[31] adder on total benefits to account for societal benefits while Iowa employs a 7.5 percent adder[32]. The use of these adders is a proxy for the range of societal benefits, which can include market transformation and emissions benefits. It should be noted, however, that Iowa allows for the separate calculation of water benefits. Missouri, Ohio, and California all recognize the limitations of the TRC in evaluating programs with substantial non-energy benefits, such as innovative technology programs. In California, if a technology does not pass a cost-effectiveness screen, the program administrators can describe the additional benefits associated with the program.[33] Missouri and Ohio both permit relaxing the requirement that all programs pass the TRC if there are potential non-energy benefits.[34,35]

197.2 What do other jurisdictions use to measure the cost effectiveness of programs such as the non- NGV Innovative Technology programs or other low carbon technologies with little or no market penetration in their jurisdiction? Do any jurisdictions exempt these types of programs from the TRC test for a set amount of time?

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[30] Colorado refers to its cost-effectiveness measure as a Modified TRC. The inclusion of a societal adder, however, indicates this is a societal test.

[31] The General Assembly of the State of Colorado (Colorado General Assembly). 2007. House Bill 07-1037: Concerning Measures to Promote Energy Efficiency, and Making an Appropriate Therefor.

[32] The Iowa Legislature. 1999. Chapter 35 Energy Efficiency Planning and Cost Review.

[33] California Public Utilities Commission. 2008. Energy Efficiency Policy Manual, Version 4.0.

[34] http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf ; http://www.senate.mo.gov/09info/pdf-bill/tat/SB376.pdf

[35] In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures. Case No. 09-512-Ged-UNC. Finding and Order. Entered October 15, 2009.

Response:

The FEU have done research to find that some jurisdictions, as listed below, do not require some enabling technologies to pass the cost benefit test if the initiative was mandated by the provincial or state government.

In 2009, Ontario passed the *Green Energy Act*, which places value on the social/environmental benefits of low-carbon renewable energy technologies above economic ones. These technologies are considered to have "inherent value" for their ability to reduce externalities and to create jobs and other social benefits.

California has also addressed the issue of the cost-effectiveness of emerging technologies. Please refer to Attachment 197.2, which contains the California Energy Efficiency Policy Manual[36] which explains that if a portfolio that includes emerging technologies does not pass a cost-effectiveness screen, the additional benefits associated with those programs can be described by the program administrators. The Manual goes on to state that the usefulness of cost effectiveness tests is "is limited for certain programs which do not necessarily focus on the timing or type of resource needs of the utility, such as programs designed to demonstrate or commercialize promising emerging energy efficiency technologies or structurally change the marketplace."

Similarly, while Missouri requires all programs to be cost effective from a TRC perspective, utilities "may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs."[37] Ohio also requires utilities to provide TRC test results for all programs and measures, but those that are not cost-effective are eligible for approval if there are demonstrable non-energy benefits.[38] Utah also permits cost-effectiveness exemptions for programs that do not pass due to early ramp-up or early implementation state.[39]

There is a clear pattern of exempting programs from cost-effectiveness requirements if they do not neatly fit into the typical concept of an energy efficiency program. Given the high costs associated with emerging technologies, their role in portfolio longevity, and non-energy economic benefits associated with these measures, it is appropriate to require cost-

[36] California Public Utilities Commission. 2008. Energy Efficiency Policy Manual, Version 4.0.

[37] http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf; http://www.senate.mo.gov/09info/pdf-bill/tat/SB376.pdf

[38] In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures. Case No. 09-512-Ged-UNC. Finding and Order. Entered October 15, 2009.

[39] "Demand Side Resource Cost Recover Collaborative Report" dated March 1995

effectiveness reporting without requiring such programs or measures pass a screen until they have achieved broader market acceptance.

197.3 If a discrete envelope of funding was approved for the non-NGV Innovative Technologies Program Area, what would the level requested be and what specific programs would be included?

Response:

The non-NGV Innovative Technologies Program area evaluates market-ready technologies and conducts pilot studies to validate manufacturer's claims about equipment, system performance and energy efficiency. FEU believes that the funding envelope for Innovative Technologies as referenced in Appendix K-1, (Section 3.2.1 Innovative Technologies - Non-NGV Initiatives, Exhibit B-1) 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. These reports and studies will be used to estimate energy savings, market availability and the adoption rate within BC's climate which will ultimately determine the feasibility of launching the pilot or demonstration project. Since this is the case, it is premature to speculate on the specific pilots that will be offered in 2012 and 2013 as they will require those reports and studies to gauge the feasibility of pilots on various technologies. The FEU can, however, provide a list of some of the opportunities that have been identified which require such reports such as:

- Thermal Curtains
  - Thermal curtains are used in greenhouses to reduce heat loss, mostly at night, thus reducing fuel consumption. As part of the BC Farms Phase 1 study conducted by Prism Engineering, the use of thermal curtains for greenhouse applications was recognised as a potential energy management opportunity. FEU requires further data to understand potential adoption rates and energy saving potential within British Columbia.

- Solar Air Heating System
  - Solar air heating system preheats outdoor air that is required for ventilation. This reduces the heating demand for the conventional natural gas-fired heating section in the existing rooftop air-handling unit. FEU requires further data to understand the energy saving potential within British Columbia and the appropriate applications.

- Occupancy Sensors/Controls
  - Room controlled HVAC systems have claimed savings through maintaining a space setpoint temperature when the room is occupied, and result in increased occupant satisfaction with their thermal environment. When the room is vacant, the Occupancy Sensor device will send a signal back to a controller, allowing for re-calculation of the room setpoint, allowing temperature to drift to a pre-programmed setback temperature to drift to a pre-programmed setback temperature and save energy. The device automatically shuts off air conditioning and or heating when a monitored door or window has been open for a period of time. FEU requires further data to understand the energy saving potential, market barriers and the appropriate applications for this technology within British Columbia.

- Condensing Make up air units (MUA)
  - Condensing Makeup air units have recently entered the marketplace in BC. Compared to the widely adopted standard efficiency MUA, Condensing Make up air units have claimed natural gas savings of up to 20% per year. FEU requires further data to understand the energy saving potential, market barriers and the appropriate applications for this technology within British Columbia.

- Advanced Control of Lumber Drying Using an Energy Management System
  - Conventional controls for direct fired (natural gas) lumber dry kilns at dimension lumber mills provide no direct way of scheduling fan speed based on actual measures of drying rate. There are claims that having a measure of the drying rate will allow adaptive drying schedules that dry the lumber precisely with less margin of error. The resulting drying schedule will dry as fast as feasible with acceptable charge degrade, minimizing drying time, and thus electrical power and natural gas usage. FEU has partnered with BC Hydro to evaluate those energy savings claims and determine the feasibility of launching a prescriptive program.

197.3.1 Please provide the FEU's views on the Commission approving a capped envelope of funding for the non-NGV Innovative Technologies programs that is exempt from the TRC test.

Response:

FEU would be supportive of the Commission approving a capped envelope of funding for the non-NGV Innovative Technologies for reasons described in BCUC IR 1.197.2;

> *"There is a clear pattern of exempting programs from cost benefit test requirements if they do not nearly fit into the typical concept of an energy efficiency program. Given the high costs associated with emerging technologies, their role in portfolio longevity, and non-energy economic benefits associated with these measures, it is appropriate to require cost-effectiveness reporting without requiring such programs or measures pass a screen until they have achieved broader market acceptance."*

and BCUC IR 1.197.1;

> *"FEU is certainly open to innovative technology programs being exempt from a requirement to pass a cost-effectiveness test. The point of innovative technology programs is to jump start fledgling market-ready technologies with substantial promise of greenhouse gas, energy-efficiency, and other benefits."*

Such an envelope should be of sufficient magnitude to allow for material activity within this program area; it is the view of the Companies that $1.5 million per year for each of 2012 and 2013 would be sufficient.

198.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, pp. 9-10

EEC Funding for Non-NGV Innovative Technologies

"The Innovative Technology programs pursue a number of objectives in order to support, review, and validate market-ready technologies. More specifically they focus on:

- *Supporting local, provincial, and federal governments with climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of clean or renewable resources; and*
- *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."*

"The Companies believe also that there is a strong need for measurement and verification of energy savings for these lower carbon technologies through conducting pilots and/or demonstration projects. The data from pilots can be used to validate manufacturer's claims about energy savings, help improve the quality and installation of future systems, and be used to understand and reduce market barriers."

198.1 Please provide a detailed breakdown of the actual activities funded in the non-NGV Innovative Technologies program in 2010 and 2011 and the specific funding amounts associated with these activities.

Response:

Below is a detailed breakdown of the actual activities funded in the non- NGV Innovative Technologies program in 2010 and 2011.

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
City of Vancouver MURB - Pilot	Rebate pilot to asses the viability of solar DHW, ventilation controls, and piping insulation for MURBs	$405
City of Courtenay Solar Pool Demonstration Project	Rebate to assess the viability of solar pool heating system for a municipal outdoor pool application	$35
Lumber Kiln Energy Management Controls Study	FEU has partnered with BCHydro to evaluate energy savings opportunities associated with adaptive controls within a lumber kiln drying process to reduce overdrying.	$25
Occupancy Sensor Study	Study to gather data to understand the energy saving potential, market barriers and the appropriate applications for occupancy sensors within British Columbia.	$39
Thermal Curtain Study	Study to understand potential adoption rates and energy saving potential within British Columbia focused around thermal curtains for greenhouse applications.	$7
Geoexchange Energy Performance Study	Study to evaluate energy savings attributable to installed geoexchange systems in MURBs, commercial and institutional buildings.	$12
Westhouse Demonstration Project	Project is a collaboration between COV, SFU and FEI to demonstrate alternative energy in a high visibiltiy location and to gain information on the operation and energy performance of the solar thermal hot water system.	$12
CESIG Gas Utilization Working Group Membership	Membership that facilitates cooperation through focused interest groups and collaborative projects surrounding forward looking and developing technologies.	$4
Total		$715

Year	Program name	Community	Installation Costs	NRCan	SolarBC	FortisBC	PSECA Contribution	Total Contributions
2010	Solar Water Heating PSECA	Victoria	$341,750	$69,383	$0	$69,383	$202,985	$341,750
2010	Solar Water Heating PSECA	Penticton	$276,250	$55,506	$0	$55,506	$165,238	$276,250
2010	Solar Water Heating PSECA	Summerland	$230,000	$41,630	$0	$41,630	$146,741	$230,000
2010	Solar Water Heating PSECA	Saanichton	$169,000	$27,753	$0	$27,753	$113,494	$169,000
2010	Solar Water Heating PSECA	Victoria	$109,000	25,637	$0	25,637	$57,726	$109,000
2010	Solar Water Heating PSECA	Vancouver	$134,270	$20,815	$0	$20,815	$92,640	$134,270
2010	Solar Water Heating PSECA	Castlegar	$132,770	$20,815	$0	$20,815	$91,141	$132,770
2010	Solar Water Heating PSECA	Kelowna	$87,700	$17,346	$0	$17,346	$53,009	$87,700
2010	Solar Water Heating PSECA	Kamloops	$106,750	$17,346	$0	$17,346	$72,059	$106,750
2010	Solar Water Heating PSECA	Kamloops	$70,550	$10,407	$0	$10,407	$49,736	$70,550
2010	Solar Water Heating PSECA	Chilliwack	$70,550	$10,407	$0	$10,407	$49,736	$70,550
2010	Solar Water Heating PSECA	Delta	$28,665	$3,699	$3,699	$3,699	$17,568	$28,665
2010	Solar Water Heating PSECA	Abbotsford	$52,700	$3,603	$3,603	$3,603	$41,892	$52,700
2010	Solar Water Heating PSECA	Abbotsford	$52,700	$3,603	$3,603	$3,603	$41,892	$52,700
2010	Solar Water Heating PSECA	Oliver	$26,000	$3,469	$3,469	$3,469	$15,593	$26,000
2010	Solar Water Heating PSECA	Oliver	$26,000	$3,469	$3,469	$3,469	$15,593	$26,000
2010	Solar Water Heating PSECA	Comox	$21,440	$2,466	$2,466	$2,466	$14,042	$21,440
2010	Solar Water Heating PSECA	Vancouver	$23,380	2,466	$2,466	$2,466	$15,982	$23,380
2010	Solar Water Heating PSECA	Vancouver	$23,180	2,466	$2,466	$2,466	$15,782	$23,180
2010	Solar Water Heating PSECA	Vancouver	$23,650	2,466	$2,466	$2,466	$16,252	$23,650
2010	Solar Water Heating PSECA	Vancouver	$22,480	2,466	$2,466	$2,466	$15,082	$22,480
2010	Solar Water Heating PSECA	Vancouver	$23,650	2,466	$2,466	$2,466	$16,252	$23,650
2010	Solar Water Heating PSECA	Campbell River	$23,870	$2,466	$2,466	$2,466	$16,472	$23,870
2010	Solar Water Heating PSECA	North Delta	$19,375	$2,466	$2,466	$2,466	$11,977	$19,375
2010	Solar Water Heating PSECA	North Delta	$20,741	$2,466	$2,466	$2,466	$13,343	$20,741
2010	Solar Water Heating PSECA	Nanaimo	$22,277	2,466	$2,466	$2,466	$14,879	$22,277
2010	Solar Water Heating PSECA	Ladysmith	$23,020	2,466	$2,466	$2,466	$15,622	$23,020
2010	Solar Water Heating PSECA	Nanaimo	$22,380	2,466	$2,466	$2,466	$14,982	$22,380
2010	Solar Water Heating PSECA	Chemainus	$21,235	$2,466	$2,466	$2,466	$13,837	$21,235
2010	Solar Water Heating PSECA	Duncan	$21,255	$2,466	$2,466	$2,466	$13,857	$21,255
2010	Solar Water Heating PSECA	Mill Bay	$21,124	$2,466	$2,466	$2,466	$13,726	$21,124
2011	Solar Air Heating PSECA	Agassiz	$51,212	$5,124	$0	$5,124	$40,964	$51,212
2011	Solar Air Heating PSECA	Surrey	$80,539	$11,900	$0	$11,900	$56,739	$80,539
2011	Solar Air Heating PSECA	Surrey	$101,553	$16,379	$0	$16,379	$68,795	$101,553
2011	Solar Air Heating PSECA	Surrey	$121,414	$21,000	$0	$21,000	$79,414	$121,414
2011	Solar Air Heating PSECA	Surrey	$95,290	$14,700	$0	$14,700	$65,890	$95,290
2011	Solar Air Heating PSECA	Williams Lake	$45,135	$4,000	$0	$4,000	$37,135	$45,135
2011	SolarBC Schools Incentive	Midway	$13,978	$1,233	$10,361	$1,233	$0	$12,827
2011	SolarBC Schools Incentive	Langley	$28,797	$2,466	$20,000	$2,466	$0	$24,932
2011	SolarBC Schools Incentive	Surrey	$23,634	$2,466	$16,832	$2,466	$0	$21,764
2011	SolarBC Schools Incentive	Burnaby	$27,619	$3,699	$18,199	$3,699	$0	$25,597
2011	SolarBC Schools Incentive	Courtenay	$21,575	$2,466	$14,979	$2,466	$0	$19,911
2011	SolarBC Schools Incentive	West Kelowna	$21,550	$4,163	$11,902	$4,163	$0	$20,228
2011	SolarBC Schools Incentive	Richmond	$39,400	$8,326	$20,000	$8,326	$0	$36,652
2011	SolarBC Schools Incentive	Duncan	$19,615	$2,466	$13,215	$2,466	$0	$18,147

198.2 Please describe the actual funded activities involved with supporting governments with climate action goals and policies and the specific funding amounts associated with these activities.

Response:

As referenced above, the FEU pursue a number of objectives in order to support, review, and validate market-ready technologies. One of those objectives is to support local, provincial, and federal governments with climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of clean or renewable resources. The FEU believe that there are two ways to support government climate action goals and policies. One is through offering additional incentives for existing government and municipal programs such as the PSECA program, the SolarBC Schools program and the COV Solar residential hot water pilot as listed in BCUC IR 1.198.1. The second is to develop and launch incentive programs from scratch such as the (0.80 EF) Hot Water Heater pilot and the NGV demonstration program. For the (.80 EF) Hot Water Heater pilot, the FEU are working with industry and utilities across Canada to launch a pilot to obtain installation, performance, and customer acceptance information regarding high efficiency water heater systems. This initiative was in response to the provincial and federal governments plan to raise efficiency levels to .80EF by 2020. For the NGV demonstration program, FEU is reducing the upfront capital cost barriers to promote the adoption of the heavy duty transportation sector to displace diesel fuel consumption and replace with low carbon natural gas. This initiative supports the goals of the *Clean Energy Act* by reducing greenhouse gas emissions in the transportation sector.

198.3 What specific pilot studies and demonstration projects were funded in 2010 and 2011? What were the results of these studies and projects?

Response:

Since the Innovative Technologies is a relatively new program area and the Innovative Technologies Program Manager was hired at the end of Q2 2010, there were no pilots launched in 2010. 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. The Solar Residential Hot Water pilot is a program launched by the City of Vancouver geared to prove the viability of solar energy in our climate for 30 residential applications. Their goals are to increase the adoption of solar hot water, reduce the city's carbon footprint, and create new jobs. FEI, SolarBC and Offsetters have partnered with the COV on this pilot initiative to gather real data on the performance and energy savings of residential solar hot water systems within this climate. The FEU are planning to install monitoring equipment on 8 of the 30 systems before the end of 2011. The MURB pilot is another pilot program launched by the City of Vancouver to prove the viability of solar energy for 15 MURB applications. FEI has partnered with the COV on this pilot initiative to gather real data on the performance and energy savings of MURB solar hot water systems within this climate. The FEU are currently researching the best practices to install, measure, evaluate and report on the energy savings associated with installing solar thermal hot water, ventilation controls and piping insulation for MURB applications.

198.4 Was any of the $372,000 or $715,000, spent in 2010 and 2011 respectively, used to provide incentives to customers for the adoption of non-NGV Innovative Technologies?

Response:

The entire amount of $372,000 for 2010 non-NGV Innovative Technologies expenditure was provided in incentives to customers under the Solar Water Heating PSECA program. This program was administered by the PSECA staff and as such, non-incentive expenditures were zero. The FEU estimate that of the $715,000 expenditure projected thus far for non-NGV Innovative Technologies for 2011, $600,000 will be used to provide incentives to customers for the adoption of non-NGV Innovative Technologies and the remainder would be used for studies, reports, EM&V, communication and administration.

198.5 Are other jurisdictions: i) undertaking pilots and/or demonstration projects to measure and verify the energy savings for lower carbon technologies; and ii) using data to validate manufacturer's claims about energy savings of lower carbon technologies? If so, why is the FEU also conducting studies and not adopting the research from other jurisdictions? If not, why is the FEU the appropriate entity to conduct pilots and/or demonstration projects and validate manufacturer's claims about energy savings on these technologies?

Response:

Yes, there are several jurisdictions undertaking pilots and/or demonstration projects to validate manufacturer's claims and/or verify energy savings such as Manitoba Hydro, Puget Sound Energy and Union Gas. Manitoba Hydro initiated a study to measure the performance of 10 existing ground source heat pump systems throughout Manitoba against manufacturers claims. Puget Sound Energy has initiated a Micro-combined Heat and Power (CHP) System for single family homes to identify energy savings potential and validate manufactures claims. Union Gas has initiated a pilot that is evaluating drain water heat recovery systems and claimed energy savings. The reason why utilities are undertaking their own pilots to determine energy savings and validate claims is because there is a lack of industry available data for their region. The FEU believe that the utility has a role to develop unbiased methodologies and monitoring systems where there is a lack of extensive third party data to measure and report on these technologies. The data will be used to determine the feasibility of developing future programs and confirming energy saving assumptions.

The FEU evaluated adopting the research from other jurisdictions but recognizes that each research piece may have different project objectives and goals, unique market barriers such as product availability, contractor expertise and customer awareness, different municipal and regulatory policies and have different climates and weather degree days. Evaluating the viability to launch programs based on the studies from other jurisdictions may increase the risk of program failure. Although basing a FEU DSM program off of a study or report from another jurisdiction is inadequate and may result in increased risk to our customers, it can be leveraged as an element to determine the viability of a particular technology where applicable. There are also opportunities to better collaborate on studies, reports, pilots and EM&V between different jurisdictions on a national level while still having representation within a study of British Columbia's climate. The (0.80 EF) Hot Water Heater pilot launching in Q4 of this year is an example of such an opportunity where FEU initiated the interest and solicited participation from other jurisdictions alongside the Canadian Gas Association (CGA) with the objective to obtain national installation, performance and customer acceptance information regarding Domestic Hot Water (DHW) technologies with an Efficiency Factor (EF) of 0.80 or better.

The 0.80 EF Hot Water Heater pilot is being run as a part of Energy Technology and Innovation Canada ("ETIC"), a new initiative of the CGA intended to ensure that natural gas and gas-enabled technologies remain a significant part of Canada's low carbon energy future. The Companies believe that it is deriving value for our customers through our involvement in ETIC as the organization is designed to address barriers to deployment and working to expedite the commercialization of new innovative energy technologies. ETIC is leveraging the collaborative investments of natural gas utilities through partnerships, both domestic and international.

The FEU have also become a member with the newly developed Gas Utilization Working Group offered by the Centre for Energy Advancement through Technological Innovations' (CEATI) in order to better understand and to collaborate on projects with other jurisdictions and interested parties. Some of possible areas for collaboration include solar thermal, motion sensor thermostats, combined heat and power and water heater technology.

198.5.1 Are other utilities in British Columbia engaged in the activities listed above?

Response:

Yes. According to section 4.2 of BC Hydro's 2008 Long Term Acquisition Plan[40], one of the goals of their Technology Innovation department is to "Engage customers and other stakeholders and partners in the demonstration and advancement of high-potential technologies and practices through demonstration projects and investigations. Determine the energy savings potential, market barriers, potential shortcomings and overall market potential in B.C. for each technology. "

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.

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40 http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/2008_ltap_appendix_k.Par.0001.File.2008_ltap_appendix_k.pdf

199.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 11, and Appendix K-4, p. 6

EEC Funding for Innovative Technologies – NGV Initiatives

"At this time, FEI offers incentive funding ranging between 80 – 100 percent of the incremental cost. This reimbursement level may decrease in the future as NGV adoption increases and cost premiums decrease ,however the exact amount and date is unknown at this time." (Appendix K-1, p. 11)

"One of the program principles put forth in the EEC Application was that of universality; that is, programs should be available to all the Companies' customers." (Appendix K-4, p. 6)

199.1 Is the NGV program a demand side measure as defined by the Utilities Commission Act? Is the provision of EEC incentives for NGVs a demand side measure as defined by the Utilities Commission Act?

Response:

The issues raised in this question have been addressed in the context of the FEI-FEVI EEC NGV Incentive Review, in which a Commission Decision is pending. Please refer to Attachment 199.1 for the specific document that outlines the FEU's position (regarding Exhibit A-6), which was submitted to the Commission on June 10, 2011 as Exhibit B-4.

It is the FEU's position that the Commercial NGV Demonstration Program, funded by EEC incentives, is a demand-side measure under the Utilities Commission Act. Further, this program could provide tangible benefits to our existing customers by adding throughput in the long-term, while providing an economic solution to customers who use CNG or LNG, while contributing to meet the provincial government greenhouse gas targets.

199.2 Please provide the guidelines by which the EEC NGV eligibility and incentive amounts are determined. What are the eligibility criteria for EEC Incentives for NGVs? Who is eligible for EEC Incentives for NGVs?

Response:

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. The program has also been designed to make the maximum use of a limited budget for incentives.

The design of the incentive program reflects the present status of the NGV market in BC. There has been no uptake of NGV's in the heavy duty trucking sector in BC and there has been minimal uptake in the transit market (50 NG transit vehicles). The lack of uptake in the market is due in large part to the higher incremental cost of NGVs and challenges regarding fueling infrastructure.

Overall there is a business case to be made that the higher cost of the vehicles can be paid back over time through reduced operating costs (i.e. lower fuel costs). However, fleet owners are not willing to take the risk that their increased investment in vehicles will be paid back; hence the market is at a standstill. In general, fleet owners will need a substantial incentive to take the risk of changing from a well proven and reliable fuel such as diesel to something new. To initiate market transformation some form of incentive is needed.

FEI's strategy for initiating market transformation from diesel to NG in BC has two primary elements:

1. Fueling Infrastructure – First address the customers concern about how he gets useful fuel delivered into his vehicles. Concerns regarding fueling infrastructure are removed when FEI is able to provide fueling service to customers. The cost of the fueling service allows customers to have a full service offering that delivers a useful product into the tank of their vehicle, versus the cost of the product that they are using now. This element of the strategy is being implemented currently through FEI's CNG and LNG Service Application before the Commission regarding provision of fueling services.
2. Capital Cost - Concerns regarding the increased capital cost are removed when an incentive is used to make the cost of the vehicle equivalent to the cost of the diesel vehicle. The customer can then weigh the economic advantages of using NG opposite the risks to his operation from making the switch. As we have seen with the four projects that we have provided incentives to (Waste Management, Vedder Transport, City of Surrey and the Kelowna School Distinct), the strategy is working.

FEI notes that these two elements, while complementary, are separate and distinct activities. The awarding of incentives is not tied to FEI's provision of fueling infrastructure.

For the four projects currently underway (Waste Management, Vedder Transport, City of Surrey and the Kelowna School Distinct), FEI has provided incentive funding of up to 100 percent of the premium cost of the NGV versus the diesel vehicle. It was necessary to go to this level to get the program started. The strategy is to engage the leading players in each sector and get them to commit to NGVs for a long term time period. Once the leading players are using NGVs and enjoying the resulting savings, the perceived risk of adopting NGVs declines. We also expect that early adopters will make full use of the advantages of their NGVs in promoting their businesses, providing additional pressure on other players in their markets to follow their lead. This dynamic means that that it will be possible to wean the market off the use of incentives over time which is the responsible approach to minimize the total amount of investment in incentives.

FEI's target market is commercial, return-to-base heavy duty fleets. This is the segment of the market that NG is best suited for. Hence the application requires the customer to divulge the amount of diesel fuel that will be displaced. At present FEI is targeting operations that have the potential to displace a minimum of 350,000 to 400,000 litres per year of diesel fuel.

Any applicant, regardless of fuel consumption level, can submit an application. From a practical perspective, however, the applicant needs to have substantial scale of operations for NGV's to make economic sense. Smaller operations will not be able to economically support the costs of the fueling stations, regardless of who is providing the fueling service. It makes little sense to provide an NGV incentive to a transport company that does not have an economical way to deliver fuel to the vehicle. In addition, the operator needs to have scale to support the training costs and the investment in upgrades to their maintenance facilities that are required for an NGV operation.

As host facilities are developed to provide fueling infrastructure, FEI plans to actively seek out smaller fleets that can fuel at the sites of larger operators. For example, in the next call for applications[41] we will seek out customers that can make use of the facilities being installed at the Waste Management ("WM") CNG site and the Vedder LNG site. This may take the form of providing incentives for as little as one or two trucks which will broaden the coverage of the market. To enable this strategy, FEI will have to make a further application to the Commission to broaden the service scope to cover third party fueling service. FEI's CNG service agreement with WM states FEI and WM intent to make WM's fueling station available for fueling service by other commercial users in a future agreement. FEI anticipates the Vedder LNG service agreement will contain a similar condition. The terms and conditions of the service to other users, and related revenue sharing arrangements, have not yet been defined or negotiated

[41] As stated in the 2010 EEC Annual Report, FEI intends to release a 'call for expressions of interest' whereby qualified fleet operators may submit an application for NGV incentive funding. This process would be communicated through industry associations such as the British Columbia Truckers Association and OEM truck dealers such as Inland Kenworth and Peterbilt.

between FEI and any of the parties. To allow for such arrangements, FEI will submit in a further application to the Commission.

In addition applicants that have their own fueling infrastructure can also apply to the program. An example is the incentive award provided to the City of Surrey for a single garbage truck.

Unlike other emerging technologies, the economic business case for NGV adoption has a reasonable payback period. Incentives are needed to kick-start the market, but should not be required once a reasonable level of market penetration has been achieved. Our strategy is to gradually ramp down the percentage of the premium covered by the incentive. FEI's first round of incentives in 2010 provided 100 percent funding. The second round will likely provide 80 percent funding. The third may be 60 percent. An intentional consequence of this funding design is that it will create a degree of urgency amongst the customer base to be among the first projects funded, else they risk having a lower funding level.

It should also be noted that the premiums between NGVs and their diesel counterparts have been declining as NGV production increases. The premium for a garbage truck has fallen from $55 thousand to $40 thousand in the BC market. Hence both the premium and the percentage of that premium that needs to be funded should decline over time. This is expected to be an effective strategy is making sure that the incentive program funds are deployed in the most effective manner possible and to ensure that they initiate market transformation in the shortest time period that is practical.

Exact timing of the changes in the funding program have not been determined as there is a need to monitor the success of the program and the rate of market transformation. It is clear, however, that the program is designed not to be a continuing subsidy to the transportation sector.

199.3 How does the provision of EEC NGV incentives to private companies accord with the FEU's principle of universality for its programs?

Response:

The FEU are uncertain as to the intention of the question. Programs should indeed be available to all the Companies' customers, and private companies make up many of the Companies' customers. The FEU have a wide range of EEC programs directed at commercial and industrial customers, as well as at residential customers, for the very purpose of meeting the principle of universality. The FEU have endeavoured within the overall EEC program to develop programs that will be relevant to all customer categories, but that is not to say that any single program will be universally relevant to all customers.

In addition, when looking specifically at the Commercial NGV Demonstration Program, of the four NGV incentives that have been awarded to date, the recipients have been:

- One privately held company (Vedder Transport)
- One publicly held company (Waste Management)
- One regional school district (Kelowna School District)
- One municipality (City of Surrey)

The diversity of awarded projects indicates that the program has broad applicability across various customer types. Of those organizations that have submitted applications for funding, the FEU have only rejected one entity and that rejection was on the basis of an unsatisfactory credit rating.

In considering the goal of universality, one must also consider the limited budget that FEU have to work with and the objectives that each program is trying to meet. The FEU have a responsibility to ensure that awards are made to the projects that will best achieve the goal of kick-starting a market transformation from diesel to natural gas and has implemented a strategy and awards criteria to ensure that awards are made to projects that help to achieve this goal. Please see our response to BCUC IR 1.199.2 for a more complete discussion and examples of the application.

199.4 How does the FEU plan to assess when the reimbursement level for NGVs should be decreased? If it is when market adoption occurs, how will the FEU know that market adoption has taken place?

<u>Response:</u>

The FEU will monitor the rate of uptake of NGVs in the target market as tracked by number of vehicles and NG consumption. There is no exact science for knowing when a market has hit the inflection point in its market adoption curve. The FEU will have to employ judgement and market knowledge and assess the overall business case to NGV users to read the appropriate points to adjust the rate of funding.

A reasonable indicator will be the number of applications that the FEU are receiving for funding compared to the available Innovative Technologies Program Area budget. Where the program is oversubscribed judgement will need to be made to determine how much the funding can be diluted and still have the NGV adoption occur.

The FEU will also continue to evaluate the overall business case for each applicant. The savings with respect to fuel costs will be compared to the costs that the customer will incur to move to NGVs. In cases where the NGV operations have been proven in similar services and the fuel savings are high a smaller level of incentive may be appropriate.

The FEU need to retain discretion on the decision points regarding the level of funding as this cannot be accurately determined in advance and it would be sub-optimal to try to apply a formulaic approach. (I.e. the FEU would risk funding free riders to a higher level than would otherwise be required if it were to lock into a set formula.)

199.5 How are the amounts of the EEC NGV incentive grants determined? Is there a standard calculation or process?

Response:

EEC NGV incentive expenditures are determined by applying a percentage of the incremental cost differential between a natural gas vehicle and its diesel equivalent. This cost is validated and documented by a third-party original equipment manufacturer ("OEM"). As engine and vehicle costs are constantly changing, FEI believes using a percentage value makes more sense than setting defined amounts.

FEI does not use a standard calculation for determining the percentage of the each incentive. As stated in our response to BCUC IR 1.199.2, fleet operators are not willing to risk investing in the upfront capital cost of NGVs. Kick-starting the market requires removal of this barrier, which means partially or wholly incenting at the incremental cost differential.

199.5.1 If there is no standard calculation, doesn't it put ratepayers at risk if there is no agreed upon or public process for how much the public utility can give to private companies as EEC NGV incentives?

Response:

To determine the EEC incentive for NGVs, FEI calculates the incremental cost differential between an NGV and a diesel equivalent vehicle.

Under the TRC or SCT tests, incentives up to the incremental cost differential between an NGV and a diesel equivalent vehicle are cost effective. This is because at present there is no free rider issue as there is minimal adoption of NGV's without incentives. Over time, however, it is expected that the percentage amount of funding needed will decline as free rider issues will develop and need to be managed. The FEU plan to wean customers off the incentive over time as the perceived risk of adopting NGVs declines. This is a fair approach in that we are providing just enough incentive to make the market move and adjusting that amount to reflect the present market conditions. Early adopters incur more perceived risk; hence they should receive a higher level of incentive. In the absence of such an approach, the FEU would end up providing higher levels of incentives than are necessary. The process of running the incentives through an economic test will ensure that incentive awards are fairly allocated. In addition, the FEU's process of canvassing the market with a call for projects at each successive stage of ramping down the incentive program will help to ensure fairness in the process.

The incentive amounts provided through the EEC NGV fuel-switching program result in cost-effective load additions which are beneficial to ratepayers. The NGV initiatives pursued to date are cost-effective and among the strongest programs in the overall EEC portfolio when assessed through the Commission-approved Total Resource Cost ("TRC") test.

NGV initiatives are also cost-effective as they reduce delivery rates to all customers. When delivery costs are shared over a greater number of GJs of natural gas, the delivery charge per GJ is reduced. 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. Finally, NGV initiatives are designed to encourage switching from higher-cost and higher GHG emitting fuels such as diesel to natural gas and therefore produce environmental benefits for all customers, help meet Provincial GHG emission reduction targets, and support BC's energy objectives.

199.6 Is the company seeking to apply the SCT to the EEC NGV incentive program?

Response:

As set out in the Application (Exhibit B-1), the FEU are proposing the use of the SCT to evaluate EEC expenditures. In general, the treatment of the SCT which the Companies are proposing uses the ceiling price of Biomethane as the marginal cost when evaluating EEC programs which reduce load.

For the NGV incentives program, the FEU are proposing a modification of the SCT to allow for the change in benchmark from Biomethane to the marginal cost of natural gas. The FEU believe that the ceiling price of Biomethane is not the appropriate marginal cost to consider for the NGV program where the initiative is designed to switch from a higher carbon fuel such as diesel to lower carbon natural gas. In the NGV incentive program case, the appropriate comparison to be used in the calculation of the SCT is the marginal cost of natural gas versus the marginal cost of the higher carbon fuel being displaced (e.g. diesel fuel).

199.7 Is the company seeking to apply freerider and/or spillover effects, if any, to the NGV Incentive Program?

Response:

To date, FEI has not applied any freerider and/or spillover effects to the NGV Incentive Program or the Total Resource Cost calculation for NGVs. By definition there is no free rider issue at the beginning of this program, because there is no adoption of NGVs in heavy duty transportation markets in BC (other than 50 NG buses).

As stated in our response to BCUC IR 1.199.2, FEI expects BC's leading fleet operators, once committed to natural gas, will place competitive pressures on the rest of the heavy duty transportation industry to adopt NGVs. FEI has not yet quantified these effects since a high degree of market transformation has not yet occurred. Only one of FEI's incented fleet operators has begun fueling its vehicles thus far.

The strategy of reducing the percentage amount of funding over time has been developed in part to provide a management tool to reduce any free rider issue that may develop.

200.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 11 and California Public Utilities Commission, California Standard Practice Manual: Economic Analysis of Demand-side Programs and Projects, October 2001, pp. 6 and 21

EEC Funding for Innovative Technologies – NGV Initiatives

"At this time, FEI offers incentive funding ranging between 80 – 100 percent of the incremental cost. This reimbursement level may decrease in the future as NGV adoption increases and cost premiums decrease, however the exact amount and date is unknown at this time." (Appendix K-1, p. 11)

"Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options". (CPUC, p. 21)

"For load building programs...[t]he Total Resource Cost and Program Administrator Cost tests are intended to identify cost effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options." (CPUC, p. 6)

200.1 Please confirm that EEC incentive grants for NGVs is part of a load building program. If so, please explain why the TRC is an appropriate cost effectiveness screen? If so, please explain why a load building program is funded, in part, by energy efficiency and conservation funding.

Response:

The TRC is an appropriate cost-effectiveness screen for the NGV incentives program because it is more properly characterized as a high-carbon fuel-switching program. The California Standard Practice Manual ("CSPM") states (at p. 2):

"Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building)".

For example, supplying natural gas buses to areas that previously did not have any buses is "load building," but displacing diesel buses with natural gas buses is "fuel switching." The

CSPM states that the TRC test (and by extension SCT, which is a modified TRC) *"is applicable to conservation, load management, and fuel substitution programs"*. Moreover, the application of the TRC or SCT test to the NGV program properly assesses the cost-effectiveness of the program. The Commission accepted the use of the TRC test for the Innovative Technologies program area in its 2009 EEC Decision and this treatment was continued in the approved 2010-11 NSAs for FEI and FEVI.

As discussed in the response to BCUC IR 1.199.6, for the NGV incentives program, the FEU are proposing to use the SCT with a modification to allow for the change in the benchmark ceiling price from Biomethane to the marginal cost of natural gas.

200.1.1 What cost effectiveness test do other jurisdictions use for load building programs? For NGV purchase incentive programs?

Response:

Please see the response to BCUC IR 1.194.2. It is the Companies' understanding that most other jurisdictions use the same test(s) for all DSM activity, regardless of whether that activity is energy efficiency, conservation, load-building, peak shaving or valley filling.

200.1.2 What is the FEU's preferred method for analyzing the cost effectiveness of purchase incentives for NGVs?

Response:

Please see the response to BCUC IRs 1.194.2 and 1.199.6. For the NGV incentives program, the FEU are proposing a modification of the SCT to allow for the change in benchmark from Biomethane to the marginal cost of natural gas. To date the FEU have been using the TRC test. A move towards the more inclusive SCT using the marginal cost of natural gas as a benchmark would result in inclusion of GHG reduction benefits, thereby further improving the test results for NGV incentive projects.

200.2 The FEU does not currently factor GHG emission reductions into its cost effectiveness test (the TRC) for NGV purchase incentives. How do GHG emission reductions factor into the cost benefit analysis of NGV purchase incentive programs? How do other jurisdictions factor GHG emission reductions into cost effectiveness tests?

Response:

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. The report, "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers"[42], states that:

> *"Another factor to consider when determining the cost-effectiveness of an energy efficiency program is how to value the program's effect on GHG emissions. The first step is to determine the quantity of avoided CO_2 emissions from the efficiency program. 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 CO_2 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 and Oregon requires that future GHG compliance costs be explicitly considered in utility resource planning. Several utilities, including Idaho Power, PacifiCorp, and Public Service Company of Colorado, include GHG emissions and costs when evaluating supply- and demand-side options, including energy efficiency, in their IRP process."*

Thus some jurisdictions include a value for GHG emissions in cost-effectiveness tests, and some do not. As stated in our response to BCUC IR 1.200.1.1, the FEU have no knowledge of other jurisdictions that use a test for NGV purchase incentive programs.

200.3 Please suggest a cost effectiveness test for purchase incentives for NGVs, that the FEU could use, that factors in GHG emissions?

[42] http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

Response:

Please see the response to BCUC IR 1.199.6.

200.4 If a FEU EEC program becomes a "prescribed undertaking" under Part 18 of the Clean Energy Act, will the budget associated with that program be removed from the total FEU EEC budget?

Response:

The provincial government has not as yet established any activities, programs or projects as prescribed undertakings under Section 18. The FEU do not know whether there will be overlap between programs or activities covered by a prescribed undertaking and programs or activities being carried out under EEC. How Section 18 prescribed undertakings will be carried out and where the funding envelope will reside in the case of programs that overlap with established EEC programs will only be known when the Section 18 regulations are established and put into effect.

201.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 12, 18

New Initiatives

"It is possible to address this funding now, as part of this RRA, because the proposed changes to the regulatory treatment of EEC funding in 2012 and 2013 will ensure that customers will not pay for the costs of these new initiatives in rates unless the programs proceed and the funds are actually spent." (p. 12)

"the Companies' new initiatives … would not be considered to be cost-effective under the TRC test." (p.18)

201.1 Please provide the cost effectiveness analysis in Excel format of both the TRC and SCT tests for each new proposed initiative. Include all inputs and assumptions.

Response:

As per the response to BCUC IR 1.204.1, detailed program planning has not yet been undertaken for the New Initiatives. The numbers used in the benefit-cost test example results provided in this response are based on the Companies' experience with similar projects in the past. Should funding be approved for some or all of the New Initiatives, detailed program plans and business cases, which include benefit-cost analysis, would be developed for approved New Initiative areas of activity.

The table below presents the TRC and SCT benefit-cost ratios for examples of a participant in New Initiative programs. The FEU analyzed the New Initiative example participants based on project type. The Thermal Energy Services ("TES") for Schools is broken down by an "elementary" (geoexchange for elementary schools), a "secondary" (geoexchange for secondary schools) and a "typical" (geoexchange based on the average of incremental cost and energy savings for elementary and secondary schools) school project. The Solar Thermal is analyzed based on 3 examples by Solar – Residential, Solar – Commercial and Solar Air. The analysis for the Furnace Scrap-It program was based upon an individual example.

Program	Project Type	TRC	SCT
Thermal Energy Services for Schools	Elementary School Project	(0.18)	0.4
Thermal Energy Services for Schools	Secondary School Project	0.31	1.72
Thermal Energy Services for Schools	Typical Project	0.14	1.26
Solar Thermal - Residential	Typical Project	0.19	0.53
Solar Thermal - Air	Typical Project	0.13	0.38
Solar Thermal - Commercial	Typical Project	0.16	0.47
Furnace Scrap-It Program	Typical Project	0.56	1.18

The TES for Schools Elementary School project resulted in a negative value TRC. This is due to this example project having an increased electric usage that exceeds the natural gas savings, resulting in a negative benefit-cost ratio. In all three examples, TES for Schools fails the TRC test due to the high incremental cost of the technology, relatively low energy use in schools and increased electric usage in geoexchange systems. TES for Schools passes the SCT for both the secondary school and typical examples; TES for elementary schools fails the SCT.

All three of the Solar Thermal scenarios fail both the SCT and TRC tests due to the high incremental costs of solar technology and prevailing low natural gas prices. It will be challenging to pursue Solar projects within the EEC portfolio unless the Companies include Solar projects within a larger portfolio of activity as has been done historically, or Solar thermal is made a prescribed undertaking in the Clean Energy Act, or if Solar Thermal is exempt from the TRC test.

The Furnace Scrap-It program does not pass the TRC but passes the SCT.

Attachment 201.1 is provided confidentially under separate cover, and contains the requested working TRC and SCT cost-effectiveness Excel workbooks. The Excel models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers.

The cost-effectiveness workbooks include all cost-effectiveness assumptions including avoided costs and discount rates. Please refer to the confidential Excel workbooks organized as referenced below:

- Attachment 201.1 TES Average SCT presents the SCT calculation for Thermal for Schools Average
- Attachment 201.1 TES Average TRC presents the TRC calculation for Thermal for Schools Average
- Attachment 201.1 TES Elementary SCT presents the SCT calculation for Thermal for Schools Elementary

- Attachment 201.1 TES Elementary TRC presents the TRC calculation for Thermal for Schools Elementary
- Attachment 201.1 TES Secondary SCT presents the SCT calculation for Thermal for Schools Secondary
- Attachment 201.1 TES Secondary TRC presents the TRC calculation for Thermal for Schools Secondary
- Attachment 201.1 Res Solar SCT presents the SCT calculation for Solar Thermal Residential
- Attachment 201.1 Res Solar TRC presents the TRC calculation for Solar Thermal Residential
- Attachment 201.1 Scrap It SCT presents the SCT calculation for Furnace Scrap-it
- Attachment 201.1 Scrap It TRC presents the TRC calculation for Furnace Scrap-it
- Attachment 201.1 Solar Air SCT presents the SCT calculation for Solar Thermal Air
- Attachment 201.1 Solar Air TRC presents the TRC calculation for Solar Thermal Air
- Attachment 201.1 Comm Solar SCT presents the SCT calculation for Solar Thermal Commercial
- Attachment 201.1 Comm Solar TRC presents the TRC calculation for Solar Thermal Commercial

201.1.1 Would any New Initiative pass the SCT test if: i) the Companies' weighted average cost of capital was used rather than a social discount rate of 3%; ii) avoided costs were revised to reflect traditional avoided gas costs rather than biomethane gas; iii) a deemed adder of 30% was not included; but all other parameters stayed the same? Please provide sensitivity analysis of the SCT for the New Initiatives with none, one, two or all of the proposed parametres of the SCT in effect and with a social discount rate of 4%, 5% and 6%.

Response:

The new initiatives can be defined as the following proposed programs:

a. Thermal Energy Systems (TES) for Schools;

b. Solar Residential;

c. Solar Commercial;

d. Solar Air; and

e. Furnace Scrap-It.

The FEU analyzed the New Initiative example participants based on project type. The Thermal Energy Services ("TES") for Schools is broken down by an "elementary" (geoexchange for elementary schools), a "secondary" (geoexchange for secondary schools) and a "typical" (geoexchange based on the average of incremental cost and energy savings for elementary and secondary schools) school project. The Solar Thermal is analyzed based on 3 examples by Solar – Residential, Solar – Commercial and Solar Air. The analysis for the Furnace Scrap-It program was based upon an individual example.

Three separate analyses are presented for the Thermal Energy for Schools initiative due to variation in costs and savings between elementary and secondary schools. The two school types are modeled separately and a third scenario analyzes an average or typical school project.

The table below illustrates 12 scenarios for each program based on the following parameters:

- Scenario 1 – 7.15% discount rate (weighted cost of capital), no adder, traditional avoided cost of gas (TRC)
- Scenario 2 – 3% discount rate, 30% adder, biomethane cost of gas (SCT)
- Scenario 3 – 7.15% discount rate, 30% adder, biomethane cost of gas
- Scenario 4 – 3% discount rate, 30% adder, traditional avoided cost of gas
- Scenario 5 – 3% discount rate, no adder, biomethane cost of gas
- Scenario 6 – 4% discount rate, 30% adder, biomethane cost of gas
- Scenario 7– 5% discount rate, 30% adder, biomethane cost of gas

- Scenario 8 – 6% discount rate, 30% adder, biomethane cost of gas
- Scenario 9 – 6% discount rate, no adder, biomethane cost of gas
- Scenario 10 – 7.15% discount rate, 30% adder, traditional avoided cost of gas
- Scenario 11 – 7.15% discount rate, no adder, biomethane cost of gas
- Scenario 12 – 3% discount rate, no adder, traditional avoided cost of gas

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
TRC 1	• 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
SCT 2	• 3% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.40	1.72	1.26	0.53	0.47	0.38	1.18
3	• 7.15% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.26	1.18	0.86	0.35	0.31	0.25	0.85
4	• 3% Discount Rate • 30% Adder • Traditional Avoided Cost of Gas	(0.26)	0.68	0.35	0.39	0.34	0.28	0.98
5	• 3% Discount Rate • No Adder • Biomethane Cost of Gas	0.30	1.32	0.97	0.41	0.36	0.30	0.91
6	• 4% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.35	1.56	1.14	0.47	0.42	0.34	1.09
7	• 5% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.32	1.42	1.04	0.43	0.38	0.31	1.00
8	• 6% Discount Rate • 30% Adder • Biomethane Cost of Gas	0.29	1.30	0.95	0.39	0.34	0.28	0.97
9	• 6% Discount Rate • No Adder • Biomethane Cost of Gas	0.22	1.0	0.73	0.3	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	0.3	0.26	0.22	0.76

The results illustrate that TES for Schools for elementary projects, Solar Thermal – Residential, Solar Thermal – Commercial, Solar Thermal - Air fail cost-effectiveness screening in all scenarios. TES for Schools for secondary projects passed all scenarios except for 1, 4, 10, 11 and 12. TES for Schools average project and the Furnace Scrap-It program passed only scenarios 2, 6 and 7 indicating that those programs are only cost effective as long as the discount rate is less than or equal to 5 percent.

201.2 When does the FEU anticipate the Ministry of Energy will finalize amendments to the DSM Regulation? What specific changes to the DSM Regulation is the Ministry of Energy considering? How certain is the FEU that changes will be made?

Response:

Staff at the Ministry of Energy and Mines have developed a work plan to review the DSM Regulation, and depending on the outcome of this review, will recommend amendments to the DSM Regulation for the Minister of Energy and Mines' consideration and approval. The work plan includes consultations during Summer 2011, with a target completion date of early September. The review will focus on broadening requirements under the Adequacy section and on alterations to the cost-effectiveness test. The final form of DSM Regulation amendments, if any, and the timing of when they occur, is subject to the approval of the Minister of Energy and Mines.

201.3 If the FEU believe they have approval to make inter and intra Program initiative funding transfers, how can customers be assured they will not pay for the $25 million proposed funding in each of 2012 and 2013 for New Initiatives unless those programs proceed?

Response:

The New Initiatives will not proceed unless the program area is approved by the Commission. While the FEU have approval to make inter and intra program area funding transfers, if the program area is approved by the Commission, the EEC accountability mechanisms, namely the EEC stakeholder group, and the EEC Annual Report, will ensure that all EEC activity, including funding area transfers, is transparent. EEC Stakeholders have the opportunity to give input to programs planned within the program area for the upcoming year during the EEC Stakeholder meeting that is held in November each year. Should the EEC Stakeholders feel that an area of activity, or a proposed funding transfer is not appropriate, the EEC Stakeholder meeting gives Stakeholders a forum to provide the FEU with that feedback.

Further, the financial treatment that the FEU have proposed, whereby $20 million of EEC funding is placed in a rate base deferral account for each of 2012 and 2013, and expenditures over and above that are accumulated, on an actual as-spent basis, in a non-rate base deferral account attracting AFUDC, will result in customers not paying for the proposed $25 million in expenditures for New Initiatives unless those programs proceed.

201.4 On page 261 of Appendix K-4, the FEU state "[b]efore a new EEC program can be implemented, a program plan or business case must first be developed." Please provide the program plan or business case for the three New Initiative programs.

Response:

The detailed program plans and associated business cases for the three New Initiative programs have not yet been developed. The FEU have done work to screen these new initiatives under the TRC and SCT test based on their experience with the technologies being proposed for New Initiatives. The results of this initial screen can be found in the response to BCUC IR 1.201.1. Once the funding is accepted, the FEU will then undertake detailed programs design and development. Developing a program takes considerable time and resources, so the Companies would prefer to focus those resources on previously-accepted areas of activity until such time as the New Initiatives activity and funding are accepted. This will ensure that customers are only paying for areas of activity that have been previously accepted. Unless funding is secured for these program areas, customers should not be paying for detailed program design and business case development. As can be seen in the response to BCUC IR 1.201.1, a change to the Societal Test will be necessary for most of these programs to proceed to program development and business case writing. The exception to this is the Solar and Thermal Energy Services – namely geoexchange – for elementary schools which do not pass the SCT, but which may have merit as programs with a goal of starting to achieve some economies of scale (in the case of solar) and educating future generations about energy conservation (in the case of TES for schools).

202.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 13 and Appendix K-4, pp.40-42

Furnace Scrap-it Program

202.1 When do customers normally retire or replace their furnace? What data or literature does the FEU have to support this?

Response:

The FEU and other gas utilities in North America use eighteen years as the expected measure life for residential heating systems in order to provide a conservative estimate of energy savings over the lifetime of the measure. This value has been obtained from the 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. BC Hydro, Power Smart. *QA Standard, Technology: Effective Measure Life*, Sept. 11, 2006, and NRCan also use 18 years as the appropriate measure life.

Although the FEU use 18 years for DSM program planning purposes, participant data from the FEU's furnace replacement programs support the fact that furnaces are in use longer than 18 years. In the 2008-2009, ENERGY STAR® Heating System Upgrade Program, 27 years was the average replaced furnace age while in the Switch 'N' Shrink oil to natural gas conversion program, 36 years was the average replaced furnace age. In the 2008 REUS study, almost 25 percent of the FEU's customers, suggested that their furnaces were more than 20 years old, with 17 percent reporting that their 25 year old furnace was still in use.

FEU Heating System Age Breakdown *

Age	# of Respondents	Percentage
<5	369	23.7%
5-9	326	20.9%
10-14	276	17.7%
15-19	205	13.1%
20-24	111	7.1%
25+	272	17.4%

* Based on data from 2008 REUS study for heating systems (furnaces and boilers) - percentages based on those participants who responded.

NRCan's Survey of Household Energy Use for 2007 further supports these findings, through the overview of the age distribution of furnaces across Canada as summarized below. British Columbians tend to have a higher proportion of old furnaces and lower proportion of new furnaces than the Canadian average, indicating their slower adoption of new models. Ontario has the highest furnace replacement rate.

Furnace Age Breakdown	BC	Alberta	Sask/Man	Ontario	Canada
5 years or less	23%	37%	29%	34%	30%
6 to 10 years	24%	23%	18%	26%	24%
11 to 15 years	15%	11%	11%	17%	15%
16 to 20 years	14%	11%	15%	13%	12%
21 to 25 years	7%	8%	12%	6%	7%
26 years or more	18%	11%	15%	5%	10%

Source: Survey of Household Residential Energy Use 2007. EcoENERGY ecoACTION initiative. Pages 34-35. Percentages based on sum of known values (Participants responding "Don't know" or "not stated" was removed from analysis in order to provide a relative comparison)

In the FEU's 2010 "Give your furnace some TLC" furnace service campaign, 15 percent of customers were advised to either replace or upgrade their furnace but cited financial considerations as the major barrier for not upgrading. The FEU believe the proposed Furnace Scrap-it program incentive will motivate such customers to advance their heating system replacement decision as much as nine years as outlined in the Conservation Potential Review. Nine years was selected as the benchmark for advancing the proactive replacement decision based on 2008 REUS data. Forty-five percent of FEU customers have standard efficiency furnaces which were last sold in 1995. In 2012, these furnaces will range in age from 17 to 35+ years. By targeting the standard efficiency market, customers will be educated about the benefits of proactive replacement ,and in doing so, replace 17-20 year old standard efficiency furnaces rather than waiting for emergency replacement of a 27-30 year old furnace. Thirty-nine percent of FEU customers have mid efficiency furnaces which range in age from 4-16 years. Those that were replaced in the mid-nineties are approaching 18 years and it would be beneficial for their proactive replacement rather than leaving them in use for another 8-10 years. Replacing existing furnaces with high efficiency models will reduce our customers' energy bills and make a substantial contribution to a greenhouse gas emissions reduction as outlined in the Conservation Potential Review.

202.2 Do other jurisdictions provide a Furnace Scrap-it Program? If so, please provide details of the program including but not limited to incentive levels, customer participation levels, resulting energy savings, and program evaluation studies.

Response:

The FEU have determined that numerous jurisdictions currently offer incentives that range from \$100 to \$750 for natural gas ENERGY STAR heating system replacement programs. These utilities include the Ontario Power Authority, Pacific Gas and Electric, Detroit Edison and MichCon, GazMetro, Excel Energy Minnesota, Consumers Energy Michigan and Avista Washington State and Idaho. Avista, in particular, provides a \$400 incentive for upgrading to an ENERGY STAR gas heating system which can be combined with an additional \$100 incentive for a variable speed motor as well as a \$750 incentive for those who replace an electric heating system with natural gas. Upon funding approval, the FEU will conduct a more in-depth investigation of these programs.

Manitoba Hydro provides the most aggressive furnace replacement program through its financing program to the "Able to Pay" market reporting 2,500 to 3,600 replacements per year. In addition, approximately 1,100 furnace replacements will be replaced through the Low Income Energy Efficiency Program (LIEEP) where customers effectively pay \$1,140 for a new furnace by making monthly payments over five years.

British Columbia is lagging behind other provinces in the adoption of installed high efficiency furnaces. While the FEU have a high efficiency penetration of 16 percent (2008 REUS), other utilities report higher penetrations. Based on customer surveys, Enbridge (2009) reports 43 percent, Union Gas reports 59 percent and Manitoba Hydro reports 37 percent penetration of installed high efficiency furnaces. The NRCan Survey of Household Energy Use for 2007 reveals similar trends with BC (18 percent) lagging behind the rest of Canada (35 percent), and especially Ontario (49 percent).

Household Furnace Efficiency Status	BC	Alberta	Sask/Man	Ontario	Canada
High Efficiency - %	18%	21%	27%	49%	35%
Mid Efficiency - %	48%	50%	39%	38%	43%
Low Efficiency - %	35%	29%	35%	13%	22%

Source: Survey of Household Residential Energy Use 2007. EcoENERGY ecoACTION initiative. Pages 34-35
Participants responding "Don't Know" or "Not Stated" was removed from analysis in order to provide a relative comparison.

202.3 Please provide a detailed breakdown of how the requested funding of $10 million in each of 2012 and 2013 would be spent on the Furnace Scrap-it program?

Response:

The Furnace Scrap-It Program is currently under development and details on breakdown of the requested funding will be finalized after receiving direction from BCUC and consultation with stakeholders such as provincial and municipal governments, manufacturers, industry associations, contractors, and customers. The intention is to make the program available to the most deserving customer segments through targeted marketing and program rules to minimize free riders and establish stringent controls and governance. Although the program has not been developed, the FEU have provided a breakdown of proposed budgetary items. The FEU would like to emphasize that this preliminary budget is only for discussion purposes.

Furnace Scrap-It Program Proposed Budget for 2012 and 2013		
	2012	**2013**
Number of Participants	8500	8500
Incentive Value	1000	1000
Participant Incentive $'s	8,500,000	8,500,000
Contractor Incentive @ $100 for certified installation	850,000	850,000
Administration @ $15/ participant	127,500	127,500
Marketing	250,000	100,000
Evaluation - Contractor and Consumer Feedback	40,000	40,000
Product Stewardship Program - Incentives @ $10	85,000	85,000
Product Stewardship Program - Marketing & Admin	100,000	100,000
Total	**9,952,500**	**9,802,500**

The proposed budget is based on the following components recognizing that these numbers are for discussion purposes only as program is still under development:

- Participant incentive: $1,000 per 8,500 participants for a total of $8.5 Million
- Contractor incentive: $100 per 8,500 contractors for a total of $850,000
    - The contractor incentive will engage contractors in driving program participation. This may include a requirement for certified installation, as introduced in the current LiveSmartBC program. A requirement for certified installation ensures

that contractors have received training to provide right-sized furnaces, another critical component for energy efficiency.

- Marketing: Investments of $250,000 in 2012 and $100,000 in 2013 could include communications partnerships with LiveSmartBC, municipal governments, furnace manufacturers and dealers to help drive program awareness. Targeted messages at neighbourhoods with older vintage homes and customers with higher than average consumption per square foot will be more cost effective than mass media.
- Product stewardship program: An expenditure of $185,000 represents a combination of incentives, program management, and outreach to contractors and customers. Please note that these numbers are for discussion purposes only and more research is required to determine the best way to structure the product stewardship program for this program and all the FEU EEC appliance replacement initiatives.

The budget will be finalized when program elements are more clearly defined.

202.4 What are the estimated energy savings from the Furnace Scrap-it Program in 2012 and 2013?

Response:

The energy savings estimates for a 2012 and 2013 Furnace Scrap-It Program are illustrated below for both cumulative annual savings and the NPV of energy savings over the lifetime of the measure. Based on the inputs for developing the TRC and SCT calculation, annual energy savings are 106,417 GJ's with 8,500 program entrants. This estimate is based on the early retirement methodology where there are increased savings attributed to the years for which the purchase decision has been advanced (9 years in the FEU's modeling) as exhibited in the second table below. The NPV of savings over the lifetime of the measure is over 1 million GJ's each year based on 8,500 program entrants. Two years of cumulative savings approach the Upper Achievable Potential estimate of 369,000 GJs outlined in the CPR representing significant energy and GHG emissions reductions for the Province.

Furnace Scrap- It - FEU Estimated Energy Savings for 2012 and 2013			
	Annual Energy Savings (GJ/yr) 2012	Annual Energy Savings (GJ/yr) 2013	Cumulative Savings (2012 & 2013) (GJ)
Lower Achievable Potential *	39,181	97,968	137,149
Upper Achievable Potential *	106,750	262,661	369,411
Year 1-9 savings - Early retirement -**	106,417	212,834	319,250
NPV of Energy Savings over the Measure Lifetime (GJ)			
2012 program entrants (8500 furnaces)			1,008,166
2013 program entrants (8500 furnaces)			1,008,166
Total for 2 year program			2,016,332

* - Based on forecasted savings in the CPR - Residential for 2012 and 2013
** Furnace Scrap-It contribution based on 8500 program participants in each of 2012 and 2013

Energy savings for an early retirement program are calculated based on the following sample chart for Lower Mainland savings. The average customer will move their purchase decision by 9 years (First Savings Period Y1-Y9) for which the energy savings are 20 percent. In the Second Savings Period (Y10 – Y18) the energy savings are 6.30 percent.

Furnace Replacement Savings Opportunities - Lower Mainland			
Program	**New Unit AFUE**	**Replaced Unit AFUE**	**Savings %**
Standard upgrade with 90% AFUE	90%	77%	14.40%
Difference in Condensing Gas Furnaces	96%	90%	6.30%
Scrap It (First Savings Period) (Y1-Y9)	96%	77%	19.79%
Scrap It (Second Savings Period) (Y10-Y18)	96%	90%	6.30%

202.5 How did the FEU determine an incentive level of $1000 per participant? What data does the FEU have to suggest that this will be a level of incentive sufficient to cause participation?

Response:

The FEU have not yet conducted primary research to determine if $1,000 is the appropriate amount, but believe that a $1,000 price point is sufficient to motivate mid-income customers to replace furnaces based on anecdotal discussions with trade partners and through informal discussions with other utilities and customer groups. Based on installed furnace costs of around $5,000, the $1,000 incentive would assist our customers in covering approximately 20 percent of the upgrade. In order to take advantage of the savings associated with early retirement, and reduce free riders, the FEU would make emergency replacement ineligible for the incentive and initially target Standard efficiency furnaces of 0.77 AFUE in order to capture the optimal savings opportunities. In developing the program, the FEU will be conducting stakeholder feedback and market research to determine if the $1,000 incentive is the best go-to market strategy.

The $1,000 incentive amount is in alignment with the provincial and federal government rebate programs as follows:

- FY 2010 LiveSmartBC iteration, furnace rebates ranged from $580 to $1,130 based on region and furnace efficiency. 31 percent of participants engaged in premium furnace upgrades.
- In the current FY 2011 LiveSmartBC iteration, furnace grants have been reduced to $500-$600.
- The federal NRCan EcoENERGY Home Retrofit program grants that ended March 31, 2011 ranged from $375 to $790.

Experience from these government rebate programs suggests that they were effective in driving heating system upgrades according to anecdotal evidence from industry partners. Sales declined noticeably when LiveSmartBC funding expired (August 16, 2009 through March 31, 2010). Layering the FEU's programs with government offers in the market during the program eligibility dates will provide substantial furnace replacement incentives for customers.

The Furnace Scrap-It program may be offered in tandem with financing programs that may have a greater appeal to certain market segments. Manitoba Hydro has had excellent success in providing a rebate offer in conjunction with their financing incentive.

202.6 If some of the furnaces replacement incentives would also go through the LiveSmartBC program, could customers receive an incentive from both the FEU and LiveSmartBC to replace their furnace? Could customers access the program through LiveSmartBC and the FEU?

Response:

The Furnace Scrap-It Program is still in the developmental stages and program implementation details have not been finalized as yet. The decision as to whether or not customers will be able to access the program directly through LiveSmartBC, or whether to create a stand-alone program with a separate FEU application process such that customers can receive rebates from both LiveSmartBC and the FEU, will be evaluated as part of program design principles and criteria in consultation with all stakeholders. When the program is designed and implemented, FEU will establish controls and frameworks to ensure that participants do not receive the same Furnace Scrap-It program incentives twice, from both the FEU and LivesmartBC. The process will be similar to other collaborative FEU incentive programs where participant lists are shared and cross-referenced prior to payment.

There are advantages to including the offer within the LiveSmartBC portfolio. One advantage for customers is to receive their payment through the LiveSmartBC process, without the need for an additional rebate application form. In addition, the LiveSmartBC requirement for a home energy assessment may encourage homeowners to undertake deeper home retrofits for additional energy savings. However, the fact that homeowners may be given 12-18 months from initial assessment to post retrofit assessment means that it could take one to two years for the FEU to receive participant data in a Furnace Scrap-It program from government, which presents challenges for budgeting and monitoring program performance.

There are numerous advantages for the FEU to create a stand-alone program that would provide an FEU incentive in addition to the heating system incentive provided through LiveSmartBC. Stand-alone program design enables the FEU to impose more stringent program rules to ensure that the rebate applies only to early retirement rather than emergency replacement. The standard mail-in rebate application process provides the opportunity to capture additional data for evaluation. The mail-in application is usually completed at the time of appliance installation and is a useful tool in engaging contractors and customers in energy efficiency dialogues, especially if a contractor incentive is provided. In addition, in order to create urgency with a time limited offer outside the contractor's already busy heating season, program eligibility dates may not align with government programs. Some homeowners do not perceive value for the $300 home energy assessment therefore waiving this requirement may drive further participation.

The final outcome of this decision will be made in consultation with the Ministry of Energy and Mines and other industry stakeholders to determine the most proactive way to accelerate the replacement of British Columbia's energy inefficient furnaces and develop a user-friendly experience that provides customer value with minimum administrative burden.

202.7 What actions has the FEU taken to ensure adequate product stewardship exists to ensure old furnaces are recycled safely? Who would pay for the cost of recycling a customer's retired furnace?

Response:

As mentioned in previous responses, the Scrap-It program has not yet been designed and details on product stewardship and associated costs have not been finalized. However the FEU have initiated preliminary discussions with a local scrap metal recycling company to gain an understanding of current appliance recycling practices as the first step in developing a product stewardship program for existing appliance replacement programs. Offered as a component of the Contractors Program, elements under consideration include education to customers and the trades, recycling incentives and potentially a community engagement strategy. Although homeowners may be charged for removal of appliances, contractors are paid a small amount (about $5-10 per appliance) for the value of the scrap metal.

In the event this program is approved, the FEU intend to go to the marketplace to identify a partner who could assist with the establishment of a product stewardship program. The primary objectives will be to educate contractors and homeowners about responsible recycling of natural gas appliances and determine if initiatives can be undertaken to ensure a higher proportion of appliances are recycled. Once established, this product stewardship program will be available for all the FEU's appliance replacement programs.

203.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, p. 14 and Appendix K-4, pp. 182-200

Solar Thermal

203.1 Please confirm that the $4 million requested per year in 2012 and 2013 will be used to fund the SolarBC Schools Incentive Program, the Solar Air Heating PSECA Program, and the Solar Residential Hot Water Pilot. Please provide a breakdown of the funding levels for each of the programs within the Solar Thermal Program Area.

Response:

Further funding from the Government of B.C. has not been allocated for the SolarBC Schools Incentive Program and the Solar Air Heating PSECA; therefore, these programs are not currently active. The Solar Residential Hot Water Pilot is a controlled pilot for a select number of participants initiated through the City of Vancouver; therefore, funding is only available within that municipality until the end of 2011.

The FEU anticipate the $4 million requested per year in 2012 and 2013 to be broken down into 3 solar program areas, Solar Thermal Hot Water – Residential, Solar Thermal Hot Water – Commercial and Solar Thermal Air – Commercial/Industrial, as can be seen in the Table below. Specific programs within these solar program areas have not yet been developed.

Solar Thermal Portfolio	2012 (000's)	2013 (000's)
Solar Thermal Hot Water - Residential	$2,000	$2,000
Solar Thermal Hot Water - Commercial	$1,500	$1,500
Solar Thermal Air - Commercial/Industrial	$500	$500
Totals	**$4,000**	**$4,000**

Each of the program opportunities presented in the Table above may have unique barriers to overcome and may require different program delivery methods and incentive calculation rates. The FEU anticipate that of the 3 program opportunities, 2 will be focused on offering energy source reductions from natural gas to solar for domestic hot water for residential and commercial applications. The remaining program referenced under solar thermal air will be focused on offering energy source reductions from natural gas to solar for space conditioning preheat for commercial and industrial applications. To name a few, the commercial and industrial applications for solar air may be warehouses, distribution centers, schools, recreation centers, poultry farms and lumber kiln drying. Natural gas would still be part of the picture as a backup fuel source for all 3 of those programs. The FEU plan to establish further details surrounding program design, delivery and controls pending funding envelope approval.

203.1.1 Will the proposed programs in 2012 and 2013 continue to be offered through SolarBC?

Response:

To clarify, the FEU have not contracted SolarBC to act as a program delivery agent for any existing or completed EEC programs. The FEU's current involvement with SolarBC is as a funding partner for programs that were initiated through the City of Vancouver and the Provincial Government.

The FEU recognize that SolarBC played a critical role in the positive momentum that was made for solar within British Columbia and will evaluate them as being a potential program delivery agent for the proposed solar programs in 2012 and 2013.

203.2 Why did Natural Resources Canada and SolarBC discontinue offering incentives for solar thermal on December 31, 2010? Did either of these programs evaluate their solar thermal incentive program? If so, please provide the evaluation studies.

Response:

Natural Resource Canada's ecoENERGY for Renewable Heat (ERH) was a four year, $36 million initiative that began April 1, 2007 and ended March 31, 2011. It was planned to be a 4 year initiative from the outset. The December 31, 2010 date for completion of projects was set and announced over a year in advance to allow for the processing and payment of any outstanding incentives, since there was no program authority or budget after March 31, 2011.

An evaluation of all of Natural Resources Canada's renewable energy programs was published in 2010, although research for some of the programs under consideration—including ecoEnergy for Renewable Heat which funded provincial solar thermal programs—was conducted in 2009. One section of particular interest in this evaluation is Annex 1, Table 4: Renewable Heat's

Results and Success[43]. Overall, the anticipated and actual results for the renewable heat program were assessed as positive and making progress toward meeting program goals by industry and government officials interviewed for the evaluation.

SolarBC was funded through a $5 million grant from the Province of British Columbia and an additional commitment of up to $1.6 million as rebates upon installation through Natural Resources Canada. This program began April 2008 and ended December 31, 2010. It was planned to be a 3 year initiative from the outset. SolarBC published annual reports for both 2009[44] and 2010[45] declaring an increased activity for solar across all sectors, engagement from municipalities, and market awareness.

Both solar program areas were initiated for a specified period of time and proved to be a success. Financial constraints at both provincial and federal governments have lead to these programs not being renewed.

203.2.1 Does the Public Sector Energy Conservation Agreement (PSECA) Funding program offer funding or do the utility partners fund it? If it does offer funding, has it been discontinued? If not, is PSECA currently offering for solar thermal initiatives and at what level?

Response:

In 2007, the Government of BC committed $75 million over three years to fund the PSECA program in addition to BC Hydro incentive funding. On June 3, 2010, the FEU signed a Public Sector Energy Conservation Agreement ("PSECA") to support additional natural gas conservation efforts through offering incentives for measures such as solar thermal and solar air. The initial $75 million in provincial government funds for PSECA has now been allocated to the projects that successfully applied for the funding available, and at the time of writing, further capital funding from the Government of B.C. has not been allocated for the PSECA program, therefore PSECA solar thermal incentives are no longer available.

[43] http://www.nrcan.gc.ca/evaluation/reprap/2010/e20100927-eng.php?PHPSESSID=35a9067bf8c3ea4dc47d9e6cfc0c6055#c5
[44] http://www.solarbc.ca/sites/solarbc.ca/files/pdf/SolarBC-AnnualReport-FINAL_2009.pdf
[45] http://www.solarbc.ca/sites/default/files/pdf/solarbc-annualreport2009-10.pdf

203.2.2 Please provide the data from the PSECA program that will be used to guide the development and feasibility of future Solar Thermal Hot Water programs.

Response:

Some of the critical components needed to guide the development and feasibility of future Solar Thermal Hot Water programs are to understand 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 potential for energy savings to validate manufacturer's claims. Through the PSECA initiative, the FEU garnered some data to better understand the level of incentives and the level of customer awareness and acceptance. Since the PSECA program covered 100 percent of the total project costs, there was a very strong uptake and full participation. The flood of applications administered through PSECA staff proved that there is an existing demand for solar thermal but required substantial incentives. The FEU also concluded that having a deadline imposed on program participants to commission the system drove urgency for the participant to initiate the contractor to work with the appropriate channels to install the system. In order to capture at least 1 full year of data, the FEU plan to undertake a billing analysis on selected projects to occur Q2 of 2012 to gather data to estimate the level of energy savings associated to the installation of solar thermal.

203.2.3 Has the solar water heating consumption data analysis on the 2010 program been completed? If so, please provide the analysis. If not, when is it expected to be complete?

Response:

The solar water heating program in question is referred to the Solar Water Heating PSECA program where the FEU committed funds for 31 provincial sector buildings to install solar thermal within 2010 and 2011. To analyze the energy savings associated to those projects, the FEU plan to undertake a billing analysis within 2012 to gather at least 1 full year of data.

203.3 Have the claimed results of 4,353 GJ saved every year from the Solar BC Residential program for solar hot water been measured and verified?

Response:

According to the SolarBC website[46], SolarBC estimates savings of 4,353 GJs per year. Monitors are currently being installed on 24 homes in order to measure and verify those claims and are unavailable. The FEU cannot speculate on the timing of this initiative.

203.4 If the Solar Water Heating PSECA Program had a TRC of 0.2 in FEI and 0.3 in FEVI and the Solar Air Heating PSECA Program had a TRC of 0.4 in FEI, what value for money will ratepayers receive if funding for the program is increased to $4 million per year as requested?

Response:

The FEU would like to clarify that the $4 million requested per year will not be used for the Solar Water PSECA Program or the Solar Air Heating PSECA Program since those programs are closed off to applications as described in the response to BCUC IR.1.203.1.1. The $4 million per year for solar thermal under the new program initiatives would be broken down into three programs, the Solar Thermal Hot Water – Residential, Solar thermal Hot Water – Commercial and Solar Thermal Air – Commercial/Industrial as further indicated in the response to BCUC IR.1.203.1. These programs do not pass the TRC but can be included in a portfolio level approach to cost-effectiveness. The Ratepayer Impact Measure results for the programs indicated above are comparable to conventional EEC programs ranging from 0.6 to 0.7. The value to ratepayers is reduced energy bills and reducing their carbon footprint. Also, as solar thermal technologies gain market acceptance, costs for these technologies may decrease dramatically while at the same time, through innovation, the performance, measure life and associated energy savings may increase. Solar thermal programs can also be used for future sources of savings within the larger non-innovative technologies EEC portfolio therefore further encouraging innovation and the longevity of portfolio savings.

[46] http://www.solarbc.ca/install/households

203.5 Are other utilities in BC or LiveSmartBC offering solar thermal incentive programs? If so, how does the FEU plan to coordinate the program offering for customers?

Response:

Yes, FortisBC Inc. (electric) and LiveSmartBC both offer incentives for solar thermal. The FortisBC Inc. PowerSense solar hot water program offers a $500 rebate to builders and developers who include solar hot water systems in new home projects and developments as well as having a $500 rebate towards retrofits to solar hot water systems for residents with existing electricity-fuelled hot water tanks. LiveSmartBC offers a $500 rebate towards solar hot water systems for residents with both electric and gas fuelled hot water tanks. Although there is a small incentive available, those budgets are inadequate to provide the kind of scale needed to start the market transformation effort for solar thermal domestic hot water. The FEU would collaborate with the existing LiveSmartBC program to offer an additional incentive for solar thermal hot water for residential customers.

204.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 14-15

Thermal Energy for Schools

204.1 Please provide a detailed breakdown of how the requested funding of $11 million in each of 2012 and 2013 would be spent on the Thermal Energy for Schools program?

Response:

At this point detailed program planning for this initiative has not yet occurred and as such it would be premature to develop a detailed breakdown of the funding amount. As noted in Appendix K- 1 in the Application (Exhibit B-1), page 12, the FEU's ability to proceed with the Thermal Energy for Schools program and other New Initiatives programs is dependent upon the BC Provincial Government amending the DSM Regulation and/or changes to the cost-effective test such as using the Societal Cost Test (SCT). Therefore further planning of the Schools program will commence when there is more certainty on the content of amendments and timing of government approval or BCUC approval is received on the FEU request in this Application to adopt the SCT.

204.1.1 What measures are expected to be promoted in the proposed schools program, and what are their corresponding TRCs?

Response:

The Thermal Energy for schools program is anticipated to provide incentives for state-of-the-art low carbon energy systems such as geoexchange systems and high-efficiency boiler upgrades.

The benefits expected from the proposed Schools program include:

- Energy conservation
- Growth of 'green economy' jobs
- Improved air quality and learning environment in school buildings
- Exposure of students and staff to energy efficiency and conservation through retrofitted buildings

- Greenhouse gas reductions
- Reductions for the schools in required emission offset purchases

While boiler upgrades have historically passed the TRC test with a value in the range of 1.0 or greater, closed loop geoexchange systems typically have a standard TRC test result that is less than 1. The Companies have undertaken some analysis of TRCs for Thermal Energy for Schools, based on their experience in the past, and this can be found in the response to BCUC IR 1.201.1.

204.2 What is meant by the phrase "the budgeted $22 million in program spending will employ a pooled approach in the cost-effectiveness evaluations for each school district"? Please explain specifically how the cost effectiveness of these programs will be evaluated.

<u>Response:</u>

By using a pooled approach for a school district, rather than evaluating each school individually, the schools can be combined into one group in order to maximize the benefits (i.e. natural gas usage reductions and GHG emission reductions) for the group while passing the applicable benefit/cost test[47]. The program would be structured to minimize GHG-emissions while ensuring economical solutions through the selection of the optimal combination of technologies to fit within both operating and capital budget constraints of the school district.

The pooled approach has the potential to increase the total number of school retrofits and expand the share of geoexchange installations and associated GHG emission reductions, while keeping incentives to an acceptable level in relation to a school district's combined equipment capital costs.

204.3 If incentives would be available for projects using a third party ownership model, will incentives be offered to private companies who will provide the thermal energy services? To whom would the program incentives be provided?

[47] As indicated in Appendix K, page 12 the EEC New Initiatives do not pass the current TRC test and require changes to the test and / or changes to the DSM Regulation. Without either or both of these changes the Thermal Energy for Schools program will not proceed.

Response:

EEC incentives are provided to natural gas customers to undertake measures to reduce their natural gas consumption. This will be the case regardless of whether the customer retains ownership of the energy system or third party ownership arrangements are in effect. In the case of the Thermal Energy for Schools program, incentives will be provided to the schools boards or schools that are having the qualifying new energy systems installed. The level of the incentives will be the same (assuming that the same energy solution has been undertaken) regardless of whether the schools continue to own and operate their own thermal energy systems or another party such as FEI or another utility owns the system and sells thermal energy to the school(s). In other words, incentives will be available for the projects undertaken by third parties, but the incentives will be paid to the school or school board rather than the private company providing thermal energy services.

FEU is willing to meet with customers and their energy service providers to discuss how EEC funds can be accessed and how customers qualify for these programs.

204.3.1 Are there other companies offering these thermal energy services in BC? If so, why should the FEU ratepayers fund the Thermal Energy for Schools incentives when a competitive market exists?

Response:

Yes, there are other potential providers of thermal energy services for schools in BC. Whether a competitive market exists for providing these services is not relevant to whether an EEC program should or should not be established in the Schools sector. By comparison, many of the FEU's residential and commercial programs are delivered by companies and service providers within the heating and ventilation sector which is comprised of many players and is a highly competitive sector. The purpose of providing EEC incentives is to stimulate incremental energy efficiency and conservation activities by the FEU's natural gas customers and is not dependent on the level of competition that exists among the service providers that will actually install the equipment or carry out the EEC activities.

The basis for the FEU providing incentives to schools and recovering the costs in rates would be the same as for the FEU providing incentives for other EEC programs – they are cost-effective EEC programs that fit within the overall EEC portfolio and assist the Companies in meeting requirements of the DSM Regulation[48].

As indicated above, the purpose of EEC or DSM incentives in general is to stimulate energy efficiency and conservation activity that would not otherwise happen. Incentives are not provided for energy efficiency and conservation activities that would have happened anyway. (In DSM language this is referred to as free ridership where an incentive is provided to a party that would have carried out the DSM activity even with no incentive). The adoption rate for the proposed low carbon thermal energy systems envisioned for the Thermal Energy for Schools program is currently very low. These systems are not being installed with any frequency because of their high initial capital costs and budget constraints within the educational system. The Thermal Energy for Schools program will provide greatly increased opportunities to meet provincial energy objectives in an educational context by promoting the adoption of state-of-the-art low carbon energy solutions.

[48] As noted in Appendix K the Thermal Energy for Schools program and other proposed New Initiatives do not pass the existing TRC test and require changes to the test and/or amendments to the DSM Regulation in order to proceed.

205.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 15-16

Elements of Existing EEC Framework to be Retained

"Most aspects of the existing EEC framework continue to make sense going forward. The key approvals previously granted to which the Companies are proposing no change are as follows:

- *The Commission approves an overall funding envelope comprised of a portfolio of approved program areas. Consistent with that notion, the Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio;*

- *Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the portfolio using the Societal Cost Test as discussed in Part 5.2.2 below);*

- *Continue to evaluate the Innovative Technologies portfolio of activity on a separate segment of the overall portfolio, with a weighted average benefit-cost test result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the Innovative Technologies portfolio using the Societal Cost Test, as the Companies are proposing in Part 5.2.2 below that the Societal Cost Test be used for all EEC activity, including Innovative Technologies);*

- *Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure;*

- *Continue to use the approved accountability mechanisms that the Companies have put in place, that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0."*

205.1 For each the above listed bulleted aspects of the EEC framework for which the FEU believes previous approvals have been granted, please provide references to those approvals. Please reference all applicable Parts of applications, information requests, Commission decisions and negotiated settlements.

Response:

Please refer to the following table.

FEU Proposed Existing EEC Framework to Continue Going Forward	Reference to Appropriate Decisions	Quotations from Appropriate Decisions
Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio.	Order G -36-09, Page 42	*Commission Panel directs that the annual EEC Report include the following:* • *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. Note: the FEU are proposing a change from the TRC to the SCT as the appropriate benefit-cost test	Order G- 36-09, Page 32	*The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives.*
	Order G - 141-09, Page 6 and 7, Section 11d and 12e	*All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6)…*
	Order G - 140-09, Page 8 and 9, Section 6c and 7d	*All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15)…*
Continue to evaluate the Innovative Technologies portfolio of activity as a separate segment of the overall portfolio, with a weighted average benefit-	Order G - 141-09, Page 6 and 7, Section 11d and 12e	... *Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. …*

FEU Proposed Existing EEC Framework to Continue Going Forward	**Reference to Appropriate Decisions**	**Quotations from Appropriate Decisions**
cost test result of 1.0 or greater.	Order G - 140-09, Page 8 and 9, Section 6c and 7d	*…Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more….*
Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure.	Order G -36-09, Page 32	*The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives. Consequently, it is important for the components of any portfolio to be capable of analysis on an individual basis. The Commission Panel directs that Terasen include in its annual EEC Report to the Commission the results of the RIM, UC, TRC and Participant tests for each proposed DSM in its portfolio, and provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0.*
Continue to use the approved accountability mechanisms that the Companies have put in place,	Order G- 36-09, Page 42	*The Commission Panel accepts Terasen's accountability undertakings*[49]

[49] Please note that the proposal for accountability mechanisms was as follows:

…Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs.

FEU Proposed Existing EEC Framework to Continue Going Forward	Reference to Appropriate Decisions	Quotations from Appropriate Decisions
that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0.	Order G -36-09, Page 42	*Commission Panel directs that the annual EEC Report include the following:* *• TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.* *• any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
	Order G - 141-09, Page 6 and 7, Section 11d and 12e	*…TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.*
	Order G- 140-09, Page 8 and 9, Section 6c and 7d	*…TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.*

205.2 To the best of the FEU's knowledge, do other utilities in BC operate under this framework? If not, does the FEU consider consistency in use of funding frameworks important for the utilities in BC?

Response:

The FEU believe that the framework should be utility specific, as it is currently the case in BC. Some elements of the framework can be applied to all utilities, but for the most part the framework should be designed to meet the EEC objectives of individual utility programs.

205.3 Please describe the level of DSM expertise among the members of the EEC Stakeholder Committee.

Response:

The level of DSM expertise among the members of the EEC Stakeholder group varies. One aim of the FEU in establishing the EEC Stakeholder group was to offer opportunities for EEC initiative input to a fairly wide variety of stakeholders as the FEU felt there would be value in having a number of perspectives around the table. The EEC Stakeholder group includes some Regulatory Intervenors, senior representatives from BC Hydro PowerSmart and FortisBC Inc. (electric) PowerSense, representatives from the City of Vancouver and the Ministry of Energy and Mines Energy Efficiency Branch and the BCUC, all of whom could be described as having a relatively high degree of DSM expertise. The Stakeholder group also includes equipment manufacturers and suppliers, gas contractors, the new construction industry, and customer groups such as multi-unit residential buildings and manufacturers, who could fairly be described as having a lower degree of DSM expertise than the first group as it pertains specifically to DSM-specific matters; however, these members bring other, valuable perspectives to the group, such as knowledge of energy-consuming equipment and installations, construction matters and customer views. The Companies' view is that the wide range of perspectives on the EEC Stakeholder group significantly enhances the value of the input the FEU receive from the group.

205.3.1 Is the FEU aware of the membership in DSM Stakeholder or Advisory committees in other jurisdictions? Please describe.

Response:

Yes; the FEU are members of the BC Hydro EC&E Committee, which similar to the FEU EEC Stakeholder group, is a varied group. The FEU are also familiar with Avista's External Energy Efficiency board, which is also a varied group.

205.4 What regulatory processes took place around the FEI-FEVI 2009 EEC Report and the 2010 EEC Report? Were the reports ever approved by the Commission?

Response:

The Commission, in its EEC Decision, by Order No. G- 36-09, directed the Companies to file annual EEC reports on all of the EEC initiatives and activities, expenditures and results. The Companies have subsequently filed the 2009 and 2010 EEC Annual Reports in order to satisfy the requirements of the EEC Decision. These reports are compliance reports, and there was no formal regulatory process that took place around the 2009 and 2010 EEC Annual Reports. The Commission does not normally approve or not approve compliance reports.

206.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, pp. 18-19

Societal Cost Test

206.1 Which specific programs in the 2010 Annual Report have been screened for cost effectiveness using the SCT?

Response:

None of the programs in the 2010 Annual Report were screened for the Annual Report using the SCT. These programs have now been put through the SCT screen in response to BCUC IR 1.191 series. Please see the response to BCUC IR 1.191 series.

207.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, p. 29

Societal Cost Test – Use of a 3 percent Social Discount Rate

207.1 Please explain how the FEU determined its social discount rate? Please provide all analysis that went into determining 3% was an appropriate rate.

Response:

The FEU have commissioned a white paper called "Options to the TRC Test" (referred to as the "TRC Options paper"), which is provided in BCUC IR 1.96.1, Attachment 196.1. Section 4.2 of the TRC Options paper includes a discussion of social discount rates used in other jurisdictions and applications, and found that social discount rates range from 1.3 percent to 5 percent. The Companies selected 3 percent as it is the median of this range, and selecting the median of the range currently being used seemed a reasonable approach.

207.2 Do other utilities, including other utilities in BC, use a social discount rate? If so, what is the rate?

Response:

The Companies are not aware that the other utilities in BC are using a social discount rate. Exhibit 2 in the TRC Options paper, (see BCUC IR 1.196.1, Attachment 196.1), shows other jurisdictions that are using a Societal Cost Test. There is a discussion of the discount rates used by various jurisdictions, and in various circumstances in Section 4.2 of the TRC Options paper. Discount rates in other jurisdictions range from 1.3 percent to 5 percent.

208.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, p. 20

Societal Cost Test – Use of the Ceiling Price of Biomethane as the Avoided Cost of Gas

208.1 Please provide in Excel format the following information:

i) Monthly average avoided gas costs that the FEU has traditionally used for TRC screening for the past 10 years.

ii) Please provide the FEU's analysis demonstrating the volatility of natural gas prices the FEU incurs in the operation of its business.

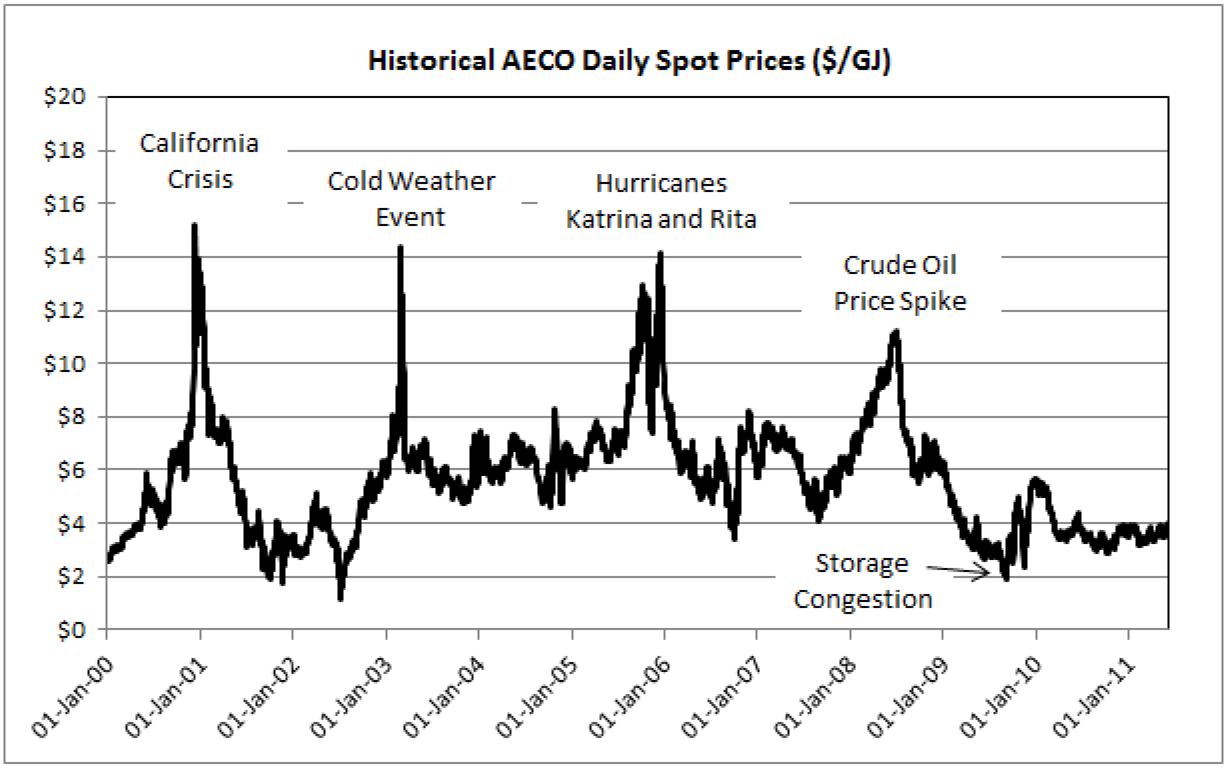
Response:

i) The table below provides the annual avoided gas cost in Cdn $/GJ for the first year in each of the years indicated including commodity and midstream. The Companies do not use a monthly avoided gas cost in TRC screening, rather an annual number is used. The Companies do not have good data on historical values used for TRC screening prior to 2003. These relatively low natural gas commodity prices are negatively affecting the amount of DSM activity considered to be cost-effective, thus the Companies are putting forward the use of the ceiling price of biomethane as the appropriate avoided cost in the DSM benefit-cost analysis.

Annual Avoided Gas Costs that FEU has historically used for TRC screening ($/GJ)							
2003	2004	2005	2006	2007	2008	2009	2010
$ 7.25	$ 7.33	$ 8.95	$ 8.28	$ 7.79	$ 11.33	$ 7.26	$ 6.41

ii) The FEU operate in the North American natural gas marketplace which is subject to periods of significant volatility. As such, the FEU take measures to mitigate this volatility to protect customers, including portfolio resource diversification, which includes the use of storage capacity, and hedging and deferral account balances. Numerous long term and short term supply and demand factors influence natural gas prices and volatility. Long term factors include economic growth or recession, increased reliance on natural gas for power generation, potential coal plant retirements and the pace of shale gas development. Short term factors include weather events (such as cold spells increasing space heating demand), hurricane disruptions to Gulf of Mexico natural gas production and the level of storage injections or withdrawals in comparison to prior years. The following graph, showing AECO daily spot prices, illustrates the volatility of natural gas prices.

Historical AECO Daily Spot Prices ($/GJ)



Some analysis regarding the volatility of natural gas prices, based on the data presented in the previous graph, is provided in the following table. It shows that market prices can fluctuate between high ranges of prices and that the degree of variability from the average, as represented by the standard deviation, is high.

	$/GJ
Average	$5.62
High	$15.16
Low	$1.14
Range	$14.03
Standard Deviation	$2.11
Std Dev. as % of Average	38%

Natural gas prices are currently in a period of relative stability due largely to the recent surge in shale gas production and depressed demand due to the recent economic recession. However, this could change quickly if hot weather in eastern parts of North America, above normal hurricane activity this summer and the shift from natural gas to oil and liquids-rich drilling continues to increase the storage deficit to last year and the five-year average going into the upcoming winter heating season. As the above figure shows, the natural gas marketplace has experienced periods of depressed market prices near current levels in the past (such as in late 2001 and early 2002), followed by a significant market price spike due to extreme weather.

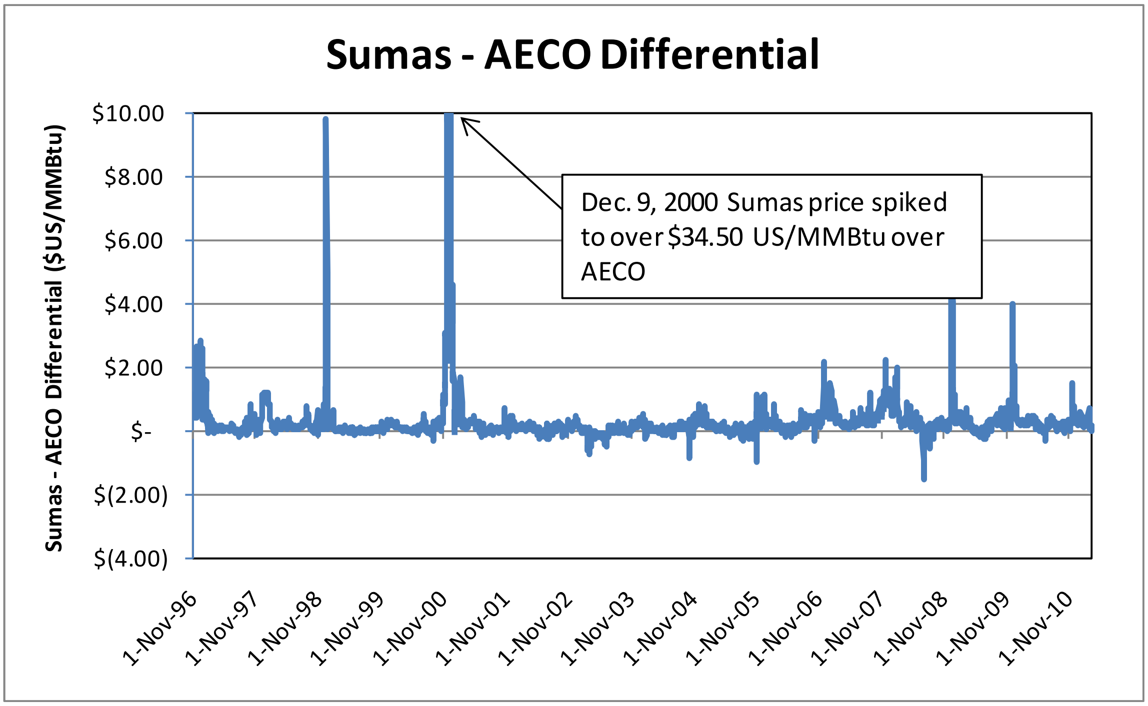
The FEU's regional natural gas marketplace also experiences significant price volatility. While the AECO marketplace consists of many buyers and sellers and is very liquid, the Sumas marketplace is less liquid and is subject to significant price spikes, or disconnections from AECO and Station 2 prices, during peak winter demand periods.

As shown in the following table and graph, historically, prices at the Sumas market hub have been much more volatile and subject to frequent disconnects from Station 2 and AECO prices. For illustrative purposes, the table below shows how often the Sumas daily price disconnected by more than $0.50 US/MMBtu over the daily Station 2 and AECO daily prices from November 1, 1996 to March 31, 2011. Over about the past 15 years, the Sumas daily price has disconnected by more than $0.50 US/MMBtu over the Station 2 daily price about 21 percent of the time, and about 12 percent of the time over the AECO daily price.

Sumas Price Disconnects from Station 2 and AECO Daily Prices

	Sumas-Station 2	Sumas-AECO
greater than $0.50 US/MMBtu disconnect	1,115	646
less than $0.50 US/MMBtu disconnect	4,134	4,603
Ratio of greater than $0.50 US/MMBtu disconnects	21%	12%

Sumas – AECO Daily Price Differential ($US/MMBtu)

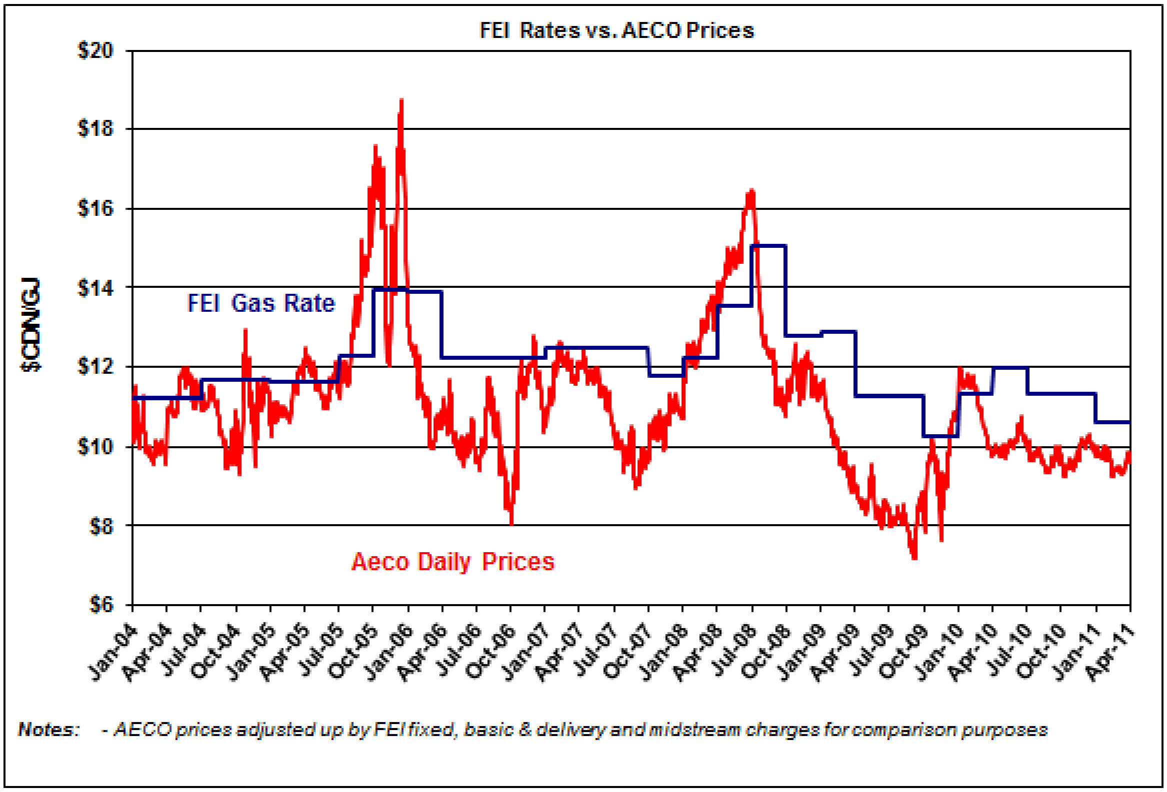


The graph above shows that, since the price spike of 2000, the price disconnections have been increasing in magnitude during the past few years. This is due to pipeline infrastructure not keeping up with increasing demand in the region and it is likely to continue in the near future.

208.2 Have the Companies' hedging policies and strategies not been effective in addressing price volatility under current market conditions? Please explain.

Response:

The FEU's hedging policies and strategies have been effective in addressing customers' exposure to price volatility in rates in the past. The FEI and FEVI Price Risk Management Plans have mitigated significant amounts of market price volatility, providing customers with relatively stable and competitive rates over time. The FEI residential rate compared to market natural gas prices is presented in the following graph and shows that the hedging program, in combination with the use of deferral account balances and quarterly rate adjustment mechanism, has been effective in mitigating significant amounts of market price volatility. With the recent decline in market prices, the FEI rate has also fallen.



With the currently depressed market prices (relative to recent historical values), the FEU, as part of the Commission directed review of the hedging objectives and strategy (per Order G-23-11 dated February 22, 2011), have reviewed the previous hedging strategy to determine if enhancements could be made. As a result of this review, FEI has proposed an enhanced hedging strategy on January 27, 2011 which is more responsive to changes in market conditions in meeting the objectives of reducing market price volatility, maintaining competitiveness and reducing the potential for significant out-of-market outcomes. As part of Order G-23-11, the Commission granted FEI permission to implement programmatic, value and basis hedging on an interim basis during the review written hearing process. This has enabled FEI to capture favourable market prices in continuing to mitigate market price volatility should it increase in the future.

FEVI currently does not have an approved hedging program in place. However, given the expiry of the royalty revenue arrangement with the Province of British Columbia at the end of 2011 and FEVI's greater competitive challenge going forward, FEVI has developed an appropriate hedging strategy to mitigate this risk and market price volatility in the short term. FEVI submitted the Hedging Request for 2012-2013 to the Commission on June 23, 2011.

208.3 Does the FEU purchase all gas at spot market prices?

Response:

The FEU have interpreted this question to mean do the FEU purchase all gas supply to meet core load requirements based on daily spot prices as determined in the natural gas marketplace. This could include daily priced purchases secured and arranged ahead of the delivery period or daily purchases bought for the next day as determined by core load requirements on a day forward looking basis. The FEU do not purchase all gas required to meet core customer loads at spot market prices. The FEU purchase gas supply based on a combination of daily spot index prices as well as monthly index prices to provide diversity in the portfolio. The FEU also utilize storage capacity wherein summer daily spot or monthly index gas is injected into storage and withdrawn during the winter period. This enables the FEU to avoid purchasing spot gas during winter months when prices are typically higher than in the summer. These purchases and resources are defined within the FEU Annual Contracting Plan ("ACP") which is developed and submitted to the Commission for approval each year. The primary objective of the ACP is to contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements.

208.4 What is the current ceiling price for biomethane versus the average cost of natural gas over the past 3 years?

Response:

The average cost of natural gas per the Sumas monthly index in Canadian dollars per gigajoule for each of the past three calendar years is as follows:

- 2008: $8.23
- 2009: $4.32
- 2010: $4.24

In Order G-194-10, the Commission approved the maximum unit price at which FEI is currently permitted to acquire pipeline-quality biomethane. The maximum unit price currently in effect is $15.280 per gigajoule. It can be seen that the commodity cost of natural gas, which is a significant input to the avoided cost of gas used to calculate DSM benefit-cost tests, was almost twice the 2010 value in 2008. This has significant impact on the amount of EEC activity that would be considered "cost-effective", thus the Companies are putting forward the use of the ceiling cost for biomethane as the appropriate avoided cost input to the DSM benefit-cost tests that the Companies apply to their EEC activity.

FEI cautions against comparing the prices of these two fundamentally different products based simply on their apparent chemical similarities. Natural gas is an established commodity traded on a North American market with differing sources, extraction costs, transportation costs and known environmental costs and benefits. Biomethane is a relatively new commodity that is capital-intensive to produce and serves as a carbon-neutral substitute for natural gas, resulting in a fundamentally different value proposition between the two commodities.

208.5 Is the FEU aware of any other jurisdictions that use the cost of biomethane as the avoided cost in DSM program cost effectiveness screening?

Response:

No, the FEU are not aware of any other jurisdictions that use the cost of biomethane as the avoided cost in DSM program cost-effectiveness screening. FEI is the one of only a few utilities in North America to offer biomethane as a supply option, so the fact that biomethane is not used in other gas utility screen tests is not unexpected.

208.5.1 What do other jurisdictions do to address the volatility of natural gas prices in their DSM cost effectiveness screening? What are other jurisdictions doing to address the low price of natural gas in their DSM cost effectiveness screening?

Response:

The Companies are aware that other gas utilities are wrestling with the challenges posed to natural gas DSM activity by low natural gas commodity prices; however, there are no published opinions or guidelines in other jurisdictions to the Companies' knowledge regarding addressing the role of gas price volatility in cost-effectiveness analysis. There is some anecdotal evidence of a movement toward addressing this issue by using the planning avoided costs as the baseline for evaluation during the plan period. For example, utilities in Iowa file updates to their DSM plan using avoided costs from the DSM plan initially submitted to the Regulator. Similarly, Piedmont Natural Gas in North Carolina provided cost-effectiveness results using the avoided costs used for program planning at the outset of program launch for an evaluation filed last year. Piedmont also provided an additional cost-effectiveness scenario in that evaluation using current avoided costs that were lower than the original planning avoided costs to demonstrate gas price sensitivity. The FEU's consultants have conducted informal interviews with other gas utilities' DSM managers; those interviewees have stressed the importance of understanding the effects of gas price volatility and low natural gas commodity prices on benefit-cost analysis.

208.6 Please discuss alternatives to using the price of biomethane to reduce the volatility of natural gas prices used in DSM cost effectiveness screening. For example could a multi-year rolling average of natural gas prices be used as the avoided cost?

Response:

In the 1970 and 80's the primary objective of DSM was to balance investment in energy supply and demand and hence reduce the cost of meeting the energy services needs of the economy. However, over time the objective of DSM programs has shifted to providing more environmentally benign energy rather than just the lowest cost energy services.

Many jurisdictions world-wide such as Ontario, the EU, Australia, China, Iran, Israel, and South Africa have added higher "feed-in" tariffs for alternate energy such as photovoltaic or wind power. The issue then arises of whether DSM should be screened against the marginal sources of "conventional" supply or against these higher-cost more benign energy sources. As DSM is typically the most environmentally benign way to meet the energy service needs of an economy, it makes sense to screen DSM programs against these alternate energy options that share similar environmental characteristics.

This change in emphasis away from lowest cost energy services is also reflected in BC Hydro's renewable portfolio standards. The requirement for 93 percent renewable/clean electricity supply provides benign energy but imposes higher marginal costs on new energy supply.

In the case of the FEU, the best proxy for a benign gaseous fuel is biomethane. However another proxy for an appropriate cost for a benign fuel could be to use the above mentioned BC Hydro renewable portfolio standard as it has been accepted as a socially acceptable price for a benign fuel.

One of the fundamental differences between BC Hydro's marginal cost for electricity and FEU's marginal cost for natural gas is that the marginal cost for electricity is based on the cost of producing electricity from an project whether that be an IPP or a major hydro electric project such as Site C. This cost tends to be stable over time as it is driven by a series of projects with long expected economic lives.

However the marginal cost of natural gas is based on various estimates of what the supply and demand for natural gas will be for multiple years in the future and is subject to much greater uncertainty and fluctuation. This fluctuation poses challenges to natural gas DSM benefit-cost analysis as in periods of high natural gas prices, the amount of DSM that appears to be "cost-effective" is greater than the amount of DSM that appears to be "cost-effective" during periods of lower natural gas prices, such as the period that we are currently in. The DSM marketplace, however, needs stable utility DSM funding in order to make the investments that support market transformation. Thus the FEU are proposing to use the ceiling price of biomethane as the appropriate avoided cost input to benefit-cost analysis, as it is more stable than commodity rates for natural gas as determined by the open marketplace for natural gas commodity, and because biomethane shares DSM's "green" environmental attributes. The suggestion of using a multi-year rolling average doesn't address this uncertainty of forecasting supply and demand conditions many years into the future.

It should be noted that the definition of the Societal Cost Test contained in the California Standard Practice Manual allows the use of higher marginal costs if its costs are lower than other utilities in the state or than its out-of-state suppliers[50]. Applying the same logic to marginal costs of alternate energy appears to be a reasonable extension of the principle.

208.6.1 Please provide in Excel format a TRC analysis for the New Initiative programs using an average of the last three years' costs of natural gas as the avoided cost.

[50] P19, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", July 2002

Response:

Please refer to Attachment 208.6.1 being provided confidentially under separate cover, which contains the requested working electronic spreadsheet model. The EEC models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers.

208.7 The FEU state "using the avoided cost of biomethane or an efficiency-adjusted cost for "green" electricity in the benefit-cost test recognizes the typically higher cost of "green" energy sources such as biogas, electricity and DSM." Does the FEU believe DSM should cost more than supply side resources? If so, why?

Response:

It is the Companies' view that as an environmentally benign alternative to conventional sources of new supply, DSM should be analyzed by applying an avoided cost that is representative of the cost of environmentally benign new supply, rather than conventional new supply. The failure of some DSM measures to pass the TRC screen using an avoided cost for conventional natural gas tells us that in the current environment of relatively low natural gas commodity prices, some DSM measures do cost more than conventional supply side resources. DSM, however, is significantly "greener" than conventional supply side resources, and using the ceiling price of biomethane as the avoided cost recognizes the "green" attributes of DSM.

208.8 With respect to biomethane as the avoided cost of gas, please further explain the meaning of "efficiency-adjusted cost of 'green' electricity."

Response:

The "cost of 'green' electricity" refers to the second tier of the BC Hydro Residential Inclining Block Rate. As stated in the Biomethane Application, the FEU believe that this is the closest thing to a proxy for the price of green energy in the Province. The "efficiency-adjusted" term refers to the assumption that the average efficiency of an electric appliance is close to 100 percent whereas the average efficiency of a gas appliance is approximately 90% and, as such, comparing usage rates between the two forms of energy requires an adjustment for efficiency.

208.8.1 Does the Company purchase biomethane gas for resale?

Response:

Yes, FEI purchases biomethane for resale to those of our customers who choose to purchase and consume it, as was approved under Commission Order G-194-10.

208.8.2 How is the use of biomethane for the production of "green" electricity similar to the cost of traditional natural gas the FEU avoids due to its energy efficiency programs?

Response:

The FEU are not suggesting that biomethane be used for the production of "green" electricity. Instead, through our biomethane program, we intend to sell it to our customers as a carbon-neutral substitute for natural gas.

The Companies view is that the "green" attributes of DSM and biomethane are very similar in that they are both environmentally more benign that conventional natural gas, therefore the price of biomethane is a more appropriate yardstick for the price of DSM than conventional natural gas.

209.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-1, p. 20

Societal Cost Test – Use of a Deemed Adder of 30% for Non-Energy Benefits

"While societal factors/non-energy benefits may be subjective or difficult to measure, they have significance."

209.1 Please provide the FEU's proposal to measure and quantify the following in support of the proposed 30% adder:

i. Incremental jobs created attributable to the FEU's energy efficiency programs.
ii. Increased health benefits from lower GHG emissions attributable to the FEU's energy efficiency programs.
iii. Improved comfort (home and business) attributable to the FEU's energy efficiency programs.
iv. Increased productivity attributable to the FEU's energy efficiency programs.
v. Reduced operating and maintenance expenses attributable to the FEU's energy efficiency programs.
vi. Water savings attributable to FEU's energy efficiency programs.
vii. Carbon taxes avoided by customers of the FEU.
viii. And any other additional non-energy benefits.

Response:

There is no standard industry relationship between non-energy benefits and energy benefits due to measure differences, regional differences in economy and weather, program offerings, and the variation in participants. It is, however, clear that the overall benefits associated with non-energy benefits are significant.

Please refer to Attachment 196.1, which contains an analysis of the impact of energy efficiency investment on the on the British Columbia economy and estimates nearly 7 additional jobs per $1 million saved in utility bills by participating customers. The output/revenue multiplier is 0.809 indicating that for each dollar of utility bills saved by participants, there is an increase in output of $0.809.[51]

Adders for non-energy benefits are best defined for low-income programs. In British Columbia, for example, the DSM Regulation provides a deemed adder of 30 percent to capture non-energy

[51] ICF Marbek. 2011. Conservation Potential Review – 20

benefits for low-income programs. Evaluation of a low-income weatherization program in Washington State found the overall non-energy benefits[52] were an additional 73 percent of energy benefits. A similar study of the Ohio Home Weatherization Assistance Program estimated non-energy benefits at 70 percent of participant lifetime bill savings. Economic benefits had a substantial impact in both cases. FEU believes its 30 percent adder is modest and conservative in light of these findings.

The following is a summary of values used for non-energy benefits associated with low-income programs in the United States as reported in a study for Sempra Utilities[53].

- ***Average savings*** can vary dramatically depending on whether the program targets high arrearage customers, but generally range between $2 and $32 decrease in the year following measure installation for each participating customer. Standard programs see a 20-30% benefit impact.

- ***Economic development and job creation*** is highly dependent on the mix of measures and region. The ACEEE recently estimated an additional 8 jobs per million dollars in energy efficiency spending for North Carolina. National Fuel in western New York uses an IMPLAN estimated multiplier of 49% of bill savings in regional economic benefits for its low income program. Overall, the highest reported multiplier is 3.54, while the lowest is 0.25 for an appliance replacement program. Economic multipliers for weatherization programs have been estimated at 46 percent for Wisconsin, 49 percent for California, and 106 percent for the U.S. overall.

- ***Improved comfort*** is one of the top non-energy benefits for low income programs and has been valued as high as $50 per year. Savings multipliers range between 2 and 12 percent.

- ***Heath benefits and reduced sick days*** benefits range between $4 and $12 for each participating household annually. The savings multiplier is approximately 181 percent of societal benefits.

- ***Reduced Customer O&M*** benefits are typically between $17 and $22 per year.

- ***Water savings.*** A typical low-income household will achieve $5 to $12 in water savings annually.

[52] Non-energy benefits included mobility, arrearages, economic and environmental benefits.

[53] Lisa Skumatz, Ph.D., Skumatz Economic Research Associates. 2010. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California.

- ***Fewer moves.*** While there are relatively few studies regarding mobility value, estimates range between $1 and $60 per participant. In societal adder terms, this is approximately 17 percent.

Additional non-energy benefits associated with low-income programs include reduced shutoff and reconnect fees, indoor air quality, fish and wildlife, and quality of light and noise, all of which can create substantial benefits.

It is expected that regular DSM programs will have many of the same non-energy benefits as those listed above. The economic impact (jobs created) tends to have the highest impact on overall benefits and, for British Columbia would be an adder of 80 percent of participant benefits. Given the additional impact of health benefits (81 percent adder), improved comfort (2-12 percent adder), avoided arrearages (20-30 percent adder), and mobility benefits (17 percent adder), a 30 percent benefits adder for the Companies' DSM programs is appropriate.

209.2 Has the Company surveyed the use of "deemed adders" in other jurisdictions? If so, please provide a detailed list of other energy efficiency program administrators using deemed adders. If available, provide the following additional information:

i. Total amount of deemed adder % or otherwise.
ii. Percent of adder attributable to job creation.
iii. Percent of adder attributable to health benefits.
iv. Percent of adder attributable to improved comfort.
v. Percent of adder attributable to productivity.
vi. Percent of adder attributable to reduced operating and maintenance expenses.
vii. Percent of adder attributable to savings.

Response:

The FEU have performed limited research on the use of "deemed adders" in other jurisdictions. Table 1 below provides a list of adders used for low-income programs in other jurisdictions. Where known, Table 2 indicates if the adder is applied to all energy-efficiency programs. FEI is not aware of any jurisdiction that provides any methodology or specific portioning of the adder to the non-energy benefits listed above. The use of an adder is generally agreed upon in lieu of quantifying non-energy benefits, particularly those associated with avoided emissions, or fish and wildlife impacts.

For this reason, utilities and program administrators are frequently permitted to include additional non-energy benefits in TRC or SCT calculations. The inclusion of non-energy benefits is most frequently applied to low-income programs, as has been done in British Colombia with the 30% deemed adder, but is often allowed for non-low income programs. The table below summarizes states that use a societal adder for the SCT or TRC. Colorado, Iowa, Oregon, Utah, and Washington apply these adders to all DSM programs, not solely low-income.

Table 1 - Low-Income Program Adders

State	Adder
California	10% adder[54]
Colorado	10% adder for electric 5% adder for gas (Colorado PUC 2008)
Idaho	10% adder[55]
Iowa	10% adder for electric 7.5% adder for gas[56]
Oregon	10% adder[57]
Utah	10% adder and non-energy benefits[58]
Washington	10% adder[59]
Wyoming	10% adder[60]

In addition to these adders, New Mexico includes a $/kWh and $/kW adder for all energy efficiency programs[61]. Vermont also includes a $/kWh adder to societal benefits[62].

[54] Lisa Skumatz, Ph.D., Skumatz Economic Research Associates. 2010. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California.

[55] Lisa Skumatz, Ph.D., Skumatz Economic Research Associates. 2010. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California.

[56] The Iowa Legislature. 1999. Chapter 35 Energy Efficiency Planning and Cost Review.

[57] Energy Trust of Oregon, Inc (ETO). 2008. 4.06.000-P Cost-Effectiveness Policy and General Methodology for Energy Trust of Oregon.

[58] Demand Side Resource Cost Recover Collaborative Report. 1995

[59] Howard Schwartz. 2008. I-937 Rules for Consumer Owned Utilities. BPA Conservation Brown Bag.

[60] Lisa Skumatz, Ph.D., Skumatz Economic Research Associates. 2010. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California.

Table 2 - Additional Non-Energy Benefits Included in TRC/SCT

State	Other Non-Energy Benefits
California	Emissions (all programs) [63]
Iowa	Water savings (all programs)
Maine	All quantifiable non-energy benefits (all programs)[64]
Massachusetts	Costs of complying with environmental regulation and laws (all programs)[65]
New York	Carbon benefit of $15/ton (all programs)[66]
Ohio	All non-energy benefits (low-income programs only)[67]
Oregon	Water, detergent, carbon emissions ($15/ton), any quantifiable benefit. Adder is applied to both avoided energy and quantified non-energy benefits. [68]
Pennsylvania	Reduced operation and maintenance costs can be included for all DSM programs. These benefits must be directly quantified. This is a benefit specifically included in the TRC by the California Standard Practice Manual.[69]
Rhode Island	Gas and water savings (all programs)[70]
Washington	Low-income programs have included benefits for avoided arrearages, avoided emissions, and economic impact, such as job creation.[71] Washington rules further specifies to include "all nonpower benefits that a resource or measure may provide."[72]

[61] State of New Mexico. Administrative Rules.

[62] Vermont Electric Energy Efficiency Potential Study (Final Report). 2007. GDS.

[63] California Public Utilities Commission (CPUC). 2001. California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects. Sacramento, CA: Governor's Office of Planning and Research, State of California.

[64] Efficiency Maine. 2010. Triennial Plan of the Efficiency Maine Trust 2011-2013.

[65] Commonwealth of Massachusetts Department of Public Utiliities. 2009. Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities.

[66] Staff of the New York State Department of Public Service (New York DPS). 2008. March 2008 DPS Staff Report on Recommendations for the EEPS Proceeding. In Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard.

[67] Public Utilities Commission of Ohio. 2009. In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures. Case No. 09-512-Ged-UNC. Finding and Order.

[68] Energy Trust of Oregon, Inc (ETO). 2008. 4.06.000-P Cost-Effectiveness Policy and General Methodology for Energy Trust of Oregon.

[69] Pennsylvania Public Utility Commission (Pennsylvania PUC). 2009. Order: Implementation of Act 129 of 2008 – Total Resource Cost (TRC) Test.

[70] State of Rhode Island and Providence Plantations Public Utilities Commission. 2002. In re: The Narragansett Electric Company, Demand-Side Management Programs for 2003.

[71] Pacific Power. 2007. Washington Low-Income Weatherization Program.

[72] Washington State Legislature. 2006. Chapter 194-37 WAC Energy Independence.

The 2010 study of low-income non-energy benefits for Sempra Utilities[73] made an effort to quantify the multipliers associated with various non-energy benefits. Those results are summarized in the response to BCUC IR 1.209.1 above.

209.3 Does the 30% deemed adder factor in the BC carbon tax?

Response:

The carbon tax is accounted for in the avoided cost of gas used by the FEU, so it is factored into the Companies' benefit/cost analysis as a benefit.

209.3.1 Given that the carbon tax exists in BC and has monetized carbon impacts, could the carbon tax be included in the TRC because it is a real cost and not an externality?

Response:

Please see the response to BCUC IR 1.209.3.

209.4 Does the FEU claim carbon credits from their EEC programs? If so, who owns these credits, the ratepayer or the shareholder?

Response:

The FEU do not currently claim carbon credits from their EEC programs. However, the terms and conditions of the FEU's incentive offerings do claim ownership of any GHG emissions reductions achieved as a result of the incentive funding. It is the FEU's view that any monetization would be to the benefit of ratepayers by either reducing rates by the credit received from sale of offsets or by the avoided cost of the FEU having to purchase offsets in the

[73] Lisa Skumatz, Ph.D., Skumatz Economic Research Associates. 2010. Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California.

case of a cap and trade scenario where these offsets could be applied to reduce the FEU's emission profile to be in compliance with regulatory GHG emissions reductions targets.

In this Application, the FEU requested approval for the rate base Compliance to Emissions Regulations Deferral Account to capture potential compliance costs to reduce our own emissions, and revenues collected from credits from renewable energy. In the future, if there are economies of scale to aggregate GHG credits across various EEC programs, as well as the appropriate protocols, regulatory and business case to do so, the FEU may be in a position monetize carbon offsets from EEC programs and these revenues would be credited to the proposed Compliance to Emissions Regulations Deferral Account.

210.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, pp. 20-21

Recognition of Spillover Effects in Net-to-Gross Ratio

" …it is important to attempt to capture additional energy savings from spillover…."

210.1 Does the FEU have a specific proposal to quantify additional energy savings from spillover effects? If so, please provide the proposal in detail.

Response:

No, the FEU do not have a specific proposal to quantify additional energy savings from spillover effects. The FEU would evaluate program effects on a program-by-program basis, using consultants to conduct surveys of program participants and non-participants, to determine both free rider rates and spillover effects. As noted during the original EEC proceeding in 2008, in which the Companies proposed to use gross energy savings to calculate benefit-cost results, free rider rates are notoriously subjective. Spillover rates are the same in that they are primarily determined by surveying individuals as to the effect that a utility DSM program has had on the respondent's actions, generally a significant amount of time after the action has been undertaken. It is the view of the Companies, however, that by not accounting for program spillover effects, and only adjusting program results downward for free rider effects, evaluation of the Companies' programs is creating a lopsided view of the Companies' EEC activity.

210.2 Is the FEU aware of other natural gas utilities where spillover effects are included in net to gross (NTG) calculations? Please provide the list of natural gas companies and the period of time such spillover effects were incorporated in the NTG analysis.

Response:

There are some natural gas utilities where spillover effects are included in NTG calculations. National Grid, for example, in Masschusetts, incorporates spillover in its NTG calculations[74]. BC Hydro also incorporates spillover effects in NTG calculations.[75] Florida, Illinois, Massachusetts,

[74] `Source: http://www.ma-eeac.org/docs/MA%20TRM_2011%20PLAN%20VERSION.PDF, pp 16 - 20

[75] `Source: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/directive_66_summary_report.Par.0001.File.2008_04_11%20DSMMES%20RPT.pdf

New York and Oregon include spillover effects, while California, Wisconsin and Connecticut do in some cases.[76]

The Companies were not able to determine the period of time such spillover effects have been incorporated into the NTG analysis in each jurisdiction, however on a practical level, this would be on a program-by-program basis, depending on the nature of the program.

210.3 Does the FEU anticipate issuing a request to deem NTG ratios for all programs, including Innovative Technologies programs and New Initiatives? If so, please provide the proposed deemed values for:

i. Freeriders
ii. Spillover
iii. Realization rates

Response:

The Companies have not requested deemed NTG ratios at this time, and as such have not determined deemed NTG ratios for free riders, spillover or realization rates, however this is certainly one approach to NTG ratios. Deeming NTG ratios could result in reduced costs for ratepayers, as highly costly evaluation studies could potentially be reduced. Deeming NTG ratios is one approach to the high uncertainty around free rider rates and spillover. Another approach, and one which the Companies put forward in the original EEC proceeding in 2008, is to accept that both free riders and spillover are highly uncertain, that they cancel each other out, and that the appropriate approach is to use gross energy savings as the benefit. Please refer to Attachment 210.3, which includes a paper, "Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way?", makes the case that for California to meet their climate change goals of reducing GHG emissions by 80 percent by 2050, transformative energy efficiency efforts will be required, that tap markets more broadly and deeply than current efforts have done, and that current evaluation methods that are focussed on free rider effects cause program administrators to focus on those programs based on measures that are easy to measure and verify, and undervalue resources spent on programs that have long lead times and high spillover effects.

[76] `Source: http://eetd.lbl.gov/ea/EMS/reports/lbnl-3277e.pdf, p 19.

210.3.1 If proposing to deem NTG, please provide the rationale for the components noted above and supporting documentation.

Response:

The Companies are not proposing to deem NTG at this time.

211.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-2

Conservation Potential Review Summary Report

211.1 Please provide a list of all measures screened for the conservation potential study that did not pass the TRC test and their corresponding cost-effectiveness ratios.

<u>Response:</u>

The list of measures screened for the Conservation Potential Review Study that did not pass the TRC test are listed in the two exhibits below. These two exhibits were developed from the following documents, included in the response to BCUC IR 1.96.1, Attachment 196.1:

- CPR Residential Sector Report
- CPR Commercial Sector Report
- CPR Industrial Sector Report

Please note the following when reviewing the exhibits listed below:

- In each sector report, chapter 5 provides the comprehensive list of measures with cost-effectiveness for each.
- Measures that pass the TRC test appear in the exhibits of savings by technology in Chapter 7 of each sector report. In some cases, measures with cost-effectiveness ratios slightly below 1.0 will have passed the economic screen for niche building segments. These measures are included in the exhibits in chapter 7, even if they pass in only one building segment in one region.
- The exhibits below were assembled by starting with the chapter 5 exhibit and excluding all measures that appear in the chapter 7 exhibit.
- No behavior measures appear in these exhibits, because all the behavior measures considered pass the TRC.
- For the industrial sector, virtually all measures considered pass the TRC. Please refer to Exhibit 26 in Attachment 196.1, (CPR Industrial Sector Report), which shows that even

the least economically attractive measure considered, the efficient small boiler for variable annual loads, fails only when it must be considered a full-cost measure.

Exhibit 1 - Residential Measures not Passing the TRC Test[77]

Measure Name	Basis (Full/ Incremental)	Weighted Average	
		B/C Ratio	Measure TRC ($)
Insulating Pool Covers	Full	0.86	-$169
DHW Recirculation Systems (e.g. Metlund D'MAND®)	Full	0.63	-$206
Air Leakage Sealing and Insulation (Old Homes)	Full	0.57	-$1,375
Wastewater Heat Recovery Systems	Full	0.49	-$399
Professional Air Sealing/Weather Stripping/Caulking	Full	0.46	-$1,086
Crawlspace Insulation	Full	0.33	-$538
Net-Zero Ready Energy Homes	Full	0.28	-$9,260
Active Solar Water Heating Systems	Full	0.24	-$5,326
Solar Pre-Heated Make-Up Air Systems (e.g., SolarWall®)	Full	0.17	-$1,073
Super High-Performance Windows	Incr.	0.56	-$1,266
Point-of-Use (Tankless) Water Heaters (Gas)	Incr.	0.42	-$1,154
Micro-Combined Heat and Power (CHP)	Incr.	0.35	-$5,163
High-Efficiency (ENERGY STAR®) Dishwashers	Incr.	0.34	-$69
Integrated Heating and DHW (Hydronic Heating)	Incr.	0.33	-$4,034
Early Retirement of Existing Gas Furnaces	Incr.	0.32	-$1,260
High-Efficiency Heat Recovery Ventilators (HRVs)	Incr.	0.31	-$412
Condensing Gas Water Heaters	Incr.	0.30	-$936
High-Efficiency Condensing Gas Furnaces	Incr.	0.28	-$1,062
Condensing Gas Boilers	Incr.	0.24	-$2,432
Zoned-Up Windows: (ENERGY STAR®) Rating for a Colder Zone	Incr.	0.23	-$1,377
Integrated Heating and DHW (Forced Air Heating)	Incr.	0.17	-$5,142
Slab Insulation (Unfinished Basements)	Incr.	0.10	-$1,069
High-Efficiency Gas-Fired Pool Heaters	Incr.	0.07	-$2,696

[77] CPR Residential Sector Report Exhibit 21, page 35, with measures excluded if they appear in Exhibit 30, page 50. These B/C ratios and TRC $ values are averages for dwellings in the Lower Mainland region.

Exhibit 1 - Commercial Measures not Passing the TRC Test[78]

Measure Name	Basis (Full/ Incremental)	Measure TRC	B/C Ratio
Solar Preheated Makeup Air	Full	$0	0.31
Solar Water Preheat	Full	-$5,576	0.25
Super High-Performance Glazing	Incr.	-$65	0.51
Wall Insulation	Incr.	-$17	0.37
High Efficiency Condensing Gas Furnaces	Incr.	-$1,017	0.31
Gas Absorption Heat Pump	Incr.	-$9,197	0.26
High-Efficiency Rooftop HVAC Units	Incr.	-$2,568	0.11

211.2 For the potential study, what discount rate was used when screening the measures? If it was the utility's cost of capital, please provide a list of any additional measures that would have passed using the proposed 3% societal discount rate, and their corresponding TRCs.

Response:

The discount rate used throughout the analysis in the Conservation Potential Review Study was 7.38 percent.

Of the measures examined in the Conservation Potential Review Study, there is one measure that would have passed the economic screen had a 3 percent societal discount rate been used. This measure is illustrated in the exhibit below:

Exhibit 2 - Residential Measures that Would Pass the TRC Test with Discount Rate of 3%

Measure Name	Basis (Full/ Incremental)	Weighted Average	
		B/C Ratio	Measure TRC ($)
Insulating Pool Covers	Full	1.04	$48

[78] CPR Commercial Sector Report Exhibit 23, page 41, with measures excluded if they appear in Exhibit 29, page 47. These B/C ratios and TRC $ values are generally based on the medium runtime application for the technology, for buildings in the Lower Mainland region.

Please note that although only one measure is listed as changing from failing the TRC to passing the TRC, there may be some measures that already pass in some building segments or regions that pass in one or two more niches under the lower discount rate. Investigating the overall change in potential under a new discount rate would require a new run of the full CPR model and cannot be done in the timeframe available for responding to this IR.

Also note that the proposed 3 percent societal discount rate is only one of the changes to the benefit/cost test that have been proposed in Appendix K of the Application. If incorporating all of the proposed changes to the benefit/cost test, additional measures may pass that were not listed as passing in the Conservation Potential Review.

211.3 In Excel format, please give all input assumptions used for screening furnace retrofits, water heaters, and solar thermal.

Response:

Please refer to Attachment 196.1 provided confidentially under separate cover, containing the requested working electronic spreadsheet models. The EEC models are being filed confidentially in order to preserve their proprietary nature on behalf of all FEU customers. Confidential Attachment 196.1 contains

- CPR TRC Model Residential Sector (Lower Mainland)
- CPR TRC Model Residential Sector (Vancouver Island)
- CPR TRC Model Residential Sector (Southern Interior)
- CPR TRC Model Residential Sector (Northern Interior)
- CPR TRC Model Residential Sector (Whistler)

Note that these models include all residential measures examined for the Conservation Potential Review Study. Per the study methodology, a model was created for each region. To view a specific measure, view the "INDEX" tab and click on the appropriate link.

211.4 In general, were the following assumptions made when screening for cost-effectiveness:

i. For retrofit measures, was there a baseline cost incurred in the year when the existing equipment would have naturally been replaced?

ii. For retrofit measures, was there a baseline savings adjustment when the old existing equipment would have been naturally replaced by new code compliant equipment"?

<u>Response:</u>

The response to the question, "*for retrofit measures (i) was there a baseline cost incurred in the year when the existing equipment would have naturally been replaced?"*, is, in general, no. The procedure was as follows:

For all measures where a full-cost analysis makes sense, the analysis was first compared against a do-nothing alternative.[79] If the measure passed on this basis, it was included in the potential as a full-cost measure. In the economic potential, that means full implementation of all opportunities right away. In the achievable potential scenarios, this obviously is slowed down by market realities, program participation rates, and missed opportunities.

Where the measure failed the full-cost test, it was then evaluated as an incremental measure, unless it made no sense as an incremental measure.[80] That means a baseline cost for the baseline technology would be subtracted from the cost of the upgrade, *in the same year*. If it failed even as an incremental measure, then it was estimated to have no savings potential. If it passed, in the economic potential it would get adopted at the rate of natural replacement. For any item with a lifetime less than 20 years, that means all the opportunities do eventually get included in the economic potential. Again, in the achievable potential scenarios, this is reduced by market realities, program participation rates, and missed opportunities.

Including a baseline cost at some future year would provide a potential in between these two calculations. It would increase total potential only for measures applied to equipment with a lifetime of more than 20 years. For shorter-lived items, it would just move the potential to earlier milestone years. Technologies that would be worth examining using this approach would be limited to the ones that already pass on an incremental basis and are relatively close to passing on a full-cost basis.

[79] Full-cost analysis is not meaningful for certain cases, such as improvements to a new house being constructed. It does not make sense to compare the efficient window against the option of not having windows installed at all.

[80] An example of a measure that makes little sense as an incremental measure is attic insulation, where there is not really an alternative other than doing nothing.

In response to the question, *"For retrofit measures (ii) was there a baseline savings adjustment when the old existing equipment would have been naturally replaced by new code compliant equipment?, a* change in the savings was not included in the analysis of the measure itself. Savings were assumed to persist through the life of the installed measure.

In the macro analysis, many measures have an assumed rate of natural penetration into the marketplace that changes with time, based on the best information we were able to obtain on likely future adoption. For such measures, there is a gradual erosion in the savings potential over time. As an example, Exhibit 30 in the CPR Residential Sector Report (see Attachment 196.1) shows the potential for programmable thermostats dropping from 1,173 GJ/year in milestone year 2015 to 657 GJ/year in milestone year 2030. This is because of customers installing programmable thermostats in the reference case, without utility involvement.

211.5 The potential study finds that, for the commercial sector, 69% of available potential consists of 4 measures – O&M, advanced building automation/retrocommissioning, high efficiency boilers and low-flow plumbing fixtures. What, if any, changes are being proposed in the 2012 efficiency portfolio to reflect these findings?

Response:

The Utilities are currently engaged in several initiatives aimed at capturing natural gas savings associated with the measures described in the preamble. These activities are outlined below.

Low flow plumbing fixtures: The FEU are actively working to bring a low-flow plumbing fixture program to market as a key component in their strategy for reducing gas consumption in multi unit residential buildings (MURBs). The currently available data is being reviewed as additional research is being conducted to evaluate whether the natural gas savings in MURBs differ from those in single family detached homes. In addition, the utilities are engaged in discussions with potential program partners such as the British Columbia Apartment Owners and Managers Association, the Condominium Home Owners Association and the City of Vancouver.

High Efficiency Boilers: the FEU foresee updating the Efficient Boiler Program in the course of 2011. The update will simplify the process, clarify the incentive determination and if justifiable, increase the incentive, all in view of encouraging additional participation and natural gas savings. In 2010 the Utilities held a stakeholder feedback session to develop a greater understanding the markets view of the program and to gather input on a revised program design. The Utilities are now completing in depth impact evaluation of the program to quantify the natural gas savings as well as further assess the overall impression of the program from past participants. The results of these initiatives will serve to guide to the program update.

Operations and Maintenance (O&M): The FEU are working to bring to market a Continuous Optimization program, in collaboration with utility partner BC Hydro, aimed specifically at generating natural gas savings from improvements to building O&M. The Utilities have completed a business case to this effect and will shortly move to develop a collaborative agreement with BC Hydro as well as the detailed program design. Note that in order to generate savings from O&M this program will require in depth re or retro commissioning work.

Advanced Building Automation: While no prescriptive program for advanced building automation is currently in development, incentives will be available for capital upgrades to building automation systems under the soon to be launched Commercial Custom Design Program. As the initiatives noted above are brought to market and successfully operationalized program development resources may be re tasked to ensuring that the Utilities have appropriate program offerings in place to capture the natural gas savings potential of advanced building automation systems.

211.6 What is the difference in the estimation methodology between the most likely and the aggressive Achievable Potential savings potential?

Response:

There is no difference in methodology between these two scenarios. The participants in the achievable workshops were asked to provide estimates of participation rates under two different scenarios of utility involvement in the marketplace. These two sets of participation rates were applied in the models in exactly the same way. The following definitions were used with the participants to help establish the philosophy behind each of the two scenarios:

- The most likely Achievable Potential assumes British Columbia market conditions that are similar to those contained in the Reference Case. That is, customers' awareness of energy-efficiency options and their motivation levels remain similar to those in the recent past, technology improvements continue at historical levels, and new energy performance standards continue as per current known schedules. It also assumes that FEU's ability to influence customers' decisions towards increased investments in energy-efficiency options remains roughly in line with previous company DSM experience.

- The aggressive Achievable Potential assumes British Columbia market conditions that aggressively support investment in energy efficiency. For example, this scenario assumes that real energy prices increase over the study period and that federal and provincial government actions to mitigate climate change result in increased levels of complementary energy-efficiency initiatives. Aggressive Achievable Potential typically does not reach Economic Potential levels; this recognizes that some portion of the market is typically constrained by barriers that cannot realistically be affected by DSM programs within the study period.

212.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-3, Table 5-25, p.120, and Appendix K-4,

Table 11-2, p. 224

Evaluation Reports

212.1 Please provide any impact evaluations the FEU have performed on existing programs. If none of the studies listed in the Tables referenced are impact evaluations, please provide a schedule of planned impact evaluations.

Response:

To date, the FEU have only performed impact evaluations on the Heating System Upgrade program and the Commercial Energy Assessment program. The 2005-2007 Heating System Upgrade program analysis was a comprehensive analysis conducted by external consultants, and was received in 2008. The Commercial Energy Assessment program has been evaluated twice; in 2008, and again in early 2010. These three impact evaluation reports are provided in Attachment 212.1

The Commercial Energy Assessment program is one of the longest running programs in the FEU's program offerings and has participants registered in the program going back at least as far as 2005. The FEU felt it was necessary to evaluate the program twice to sample participants from 2005 to 2007 and from 2007 to 2009. The initial evaluation found that the program led to total natural gas savings of 128,950 GJ during the study period, while the second evaluation found total savings of 249,748 GJ. Both evaluations found that the program did effectively encourage natural gas savings, with manufacturing sector participants responsible for the majority of the savings. Please refer to Attachment 196.1 which contains the Conservation Potential Review.

In order to obtain meaningful results, impact evaluations are performed post implementation solely for those programs that have been in the market place for two to three years. Going forward, as programs reach a certain level of maturity, and program data becomes available, the FEU would undertake impact evaluations at appropriate times. For example, the FEU are currently in the process of completing an impact evaluation of the Efficient Boiler Program and an Enerchoice Fireplace program study. Additionally, BC Hydro is leading a comprehensive LiveSmartBC program analysis that will be conducted over the next 12 months; the FEU will provide financial contributions to gain access to this analysis. For the affordable housing programs such as Energy Savings Kits, which have been in-market since July 2010, and where data is becoming available, the FEU plan to conduct surveys to estimate the accuracy of initial assumptions used for installation rates of various measures. For the Innovative Technologies

Program area, the FEU are currently evaluating measurement and verification best practices and methodologies for monitoring solar thermal hot water, solar pool heating and high efficient water heater technologies. For Conservation Education and Outreach ("CEO"), the Companies plan to conduct research on the effectiveness of this program area throughout 2011. For example FEU is conducting a bill insert and bill messaging research study to determine readership level and understand if certain CEO messages garner more attention from readers than other messages. Other CEO studies planned include EEC event and long-term tracking to determine the success of the overall approach (event attendance and/or sports team partnerships) and to track awareness levels for EEC messaging, message retention, and programs over time among the residential and general public audience respectively. Please also see the response to BCUC IR 1.216.2.3 for the FEU's evaluation plan for the Destination Conservation for Public Buildings pilot. Please also see the responses to BCUC IRs 1.212.2 and 1.212.2.1 for FEU's EEC evaluation framework and go forward plans on adding more resources to build capacity internally to carry out analysis, research and establish additional controls for evaluation of existing and future programs.

This data will be used to confirm savings claims and guide the development of future programs within the appropriate sectors.

212.1.1 Have any evaluations (or other) studies estimated the level of free ridership in FEU service areas? Please provide supporting documents, if available.

Response:

Evaluations of free ridership generally need to be done on a program-by-program basis, as they can vary significantly between programs, depending on the program's target audience and nature. It is common practice to evaluate programs and estimate free ridership ("FRR") for just those programs that have been in-market long enough to obtain meaningful results. For example the FRR results from the Energy Star Heating Upgrade Program which was evaluated for the years 2005–2007 and the Commercial Energy Assessment program that was evaluated in 2008 and again in early 2010 have been incorporated for future program development purposes and estimating savings. Copies of these evaluations have been attached in response to BCUC IR 1.212.1.

FEU received approval for the increase in EEC expenditure in April 2009, and the focus of the EEC group to date has been on hiring and training program Managers and developing the increased suite of programs and pushing them into the Marketplace, as well as establishing systems and procedures and reporting out to stakeholders. Thus the additional programs that have been introduced to the marketplace since the EEC Application was approved are relatively new.

A number of different approaches have been used by FEU to estimate the free ridership rates:

1. In cases where FEU has operated a program which has been evaluated, the free rider rate from the evaluation has been used. In the evaluations, the FRR has typically been determined by a combination of information from: a customer survey; a trade ally survey; and in some cases by discrete choice analysis modeling using participant and non-participant data.

2. For other programs, the approach has been to estimate the ratio of existing energy efficient products sold prior to the program launch and the estimated program sales after the launch.

3. In some cases, other utilities have operated similar programs in the same or similar marketplaces. In this case, the FRR from the other utility program has been used. For example, in the Energy Savings Kit partnership with BC Hydro, the Companies were able to leverage the analysis BC Hydro performed on a customer survey. This lead to the Companies adjusting their assumptions on the installation rates of the various measures and the free rider rates.

4. In some cases, judgment has been applied based on the opinion of industry people outside of the utility or FEU field staff who work closely with the trades and major customers.

The Companies have argued in prior regulatory proceedings that the requirement to net out energy savings resulting from the participation of "free riders" be eliminated from the cost-benefit analyses for EEC programs in British Columbia. It is the Companies' view that it is the energy consumption reduction outcome that matters, not the way in which it was achieved. Program evaluations that attempt to quantify free rider ratios are more costly than those that make no attempt to quantify free rider ratios due to the need to conduct surveys. The Companies believe that free rider rates are notional because of their subjectivity, and using them in analysis such as the DSM cost-benefit tests along with the other "hard" inputs to the tests, which are more easily quantified, diminishes the value of those tests. The Utilities proposed in the EEC Application to exclude the free rider impact from cost-benefit analysis for the Companies' EEC programs. This proposal was rejected in the April 16, 2009 Decision on the EEC Application and therefore the FEU include the impact of free riders in its energy savings calculations. In this Revenue Requirements Application, in order to present a more balanced view of the impacts of the Companies' EEC activity, the Companies are proposing to recognize spillover effects as well as free rider effects in the net-to-gross ratio applied to the Companies estimates of EEC program impacts, despite the same subjectivity issues with spillover as exist with free rider rates.

212.1.2 Have any evaluations (or other) studies estimated the level of spillover in FEU service areas? Please provide supporting documents, if available.

Response:

The FEU have not conducted any formal evaluation or studies to estimate the level of spillover in FEU service territory. Please refer to 212.1.1 for additional information on the Companies' approach to spillover. The program results presented in the 2009 and 2010 EEC Annual Reports do not incorporate any estimates of the impacts of spillover on the net-to-gross ratio; they only incorporate free rider impacts. As such, the net-to-gross ratio is lower than it would be should the Companies incorporate spillover effects into net-to-gross ratio, as any assumed spillover effects would to some degree mitigate any assumed free rider effects.

212.2 What is the FEU EEC evaluation framework or schedule? Please provide.

212.2.1 Does the increase in proposed spending on EEC warrant a more formalized structure for program evaluation?

Response:

The FEU consider Evaluation, Measurement and Verification ("EM&V") to be an extremely important aspect of overall program lifecycle. The FEU's current evaluation frameworks are well aligned with industry best practices and other utilities as stated in the response to BCUC IR 1.192.4.3. As the FEU begin to push more programs into the market and as existing programs reach a certain level of maturity, the Companies would continue to make refinements to meet individual program goals. A high level overview of the FEU's framework is described below. The increase in program spending requires greater focus on Evaluation, Measurement and

Verification, and the Companies have in their staffing plans for 2011, a dedicated EM&V Manager to put a formal structure and an evaluation framework to support all the EEC programs in-market. The EM&V Manager would also study other similar Utilities to understand their current process and implement best practices in FEU.

The FEU's current evaluation framework varies between EEC program areas and initiatives. For prescriptive programs, the Companies rely on EM&V methodologies, such as billing analysis, statistical estimates, and site specific market research, using control and program participant samples to determine the effects of EEC activities and measure implementation. For example, for the Heating System Upgrade program, the FEU sampled the participants and a group of nonparticipants (a randomly selected control group) to analyze normalized consumption levels both prior and subsequent to participating in that program, which results in the savings for participants being estimated. Normalizing consumption data to remove the weather effect from the data and including a control group (that did not participate in the program) enables the Companies to conclude that other external factors impact the participants in the same manner as they do the non-participant. For such evaluations, the program managers typically allocate anywhere from 3-5 percent of their overall budget towards evaluation.

For pilots, demonstration and/or "proof of concept" projects, the FEU rely on real-time monitoring equipment such as sensors, data loggers to better evaluate real-time data of the performance and energy savings of the measure. These 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. For example, the EM&V allocation for the solar residential COV pilot is approximately 50 percent of the overall budget and the EM&V allocation for the hot water pilot is 20 percent of the overall budget.

Until now, the FEU have heavily relied on independent third-party consultants to evaluate the Companies' EEC programs. The consultants are selected based on relevant experience and cost. Once selected, the consultant then develops the detailed evaluation plan for review and discussion with FEU. When the plan has been approved, the consultant typically develops any necessary market research (for example with participants and with the relevant trade allies), conducts the analysis and develops a report.

213.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, p.6 and 9

FEI-FEVI 2010 EEC Report

Table 2-1: 2010 Overall EEC Portfolio Results

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	10,548	5,261	15,809	(17,507)	532,929	1.1
FEVI	870	1,022	1,892	22,389	169,030	0.9
Total	**11,418**	**6,283**	**17,701**	**4,882**	**701,959**	**1.1**

The "Annual Energy Savings" number for FEI is negative, meaning from a simple annual perspective, the Companies' 2010 activity resulted in natural gas load growth. This is primarily due to the impact of Natural Gas Vehicles ("NGVs"), which is discussed in some detail in Section 10. It should be noted that NGVs bring load onto the natural gas system, but they displace higher carbon diesel fuel; displaced volumes of diesel fuel are not shown in the table above.

213.1 Please provide Table 2-1 with the NGV program removed.

Response:

The table below shows Table 2-1 with the NGV program in FEI removed.

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	4,961	5,259	10,220	147,983	1,288,378	0.9
FEVI	870	1,022	1,892	22,389	169,030	0.9
Total	**5,831**	**6,281**	**12,112**	**170,372**	**1,457,408**	**0.9**

It can be seen from the table above that NGV is a strong contributor to the overall portfolio TRC. This results from the benefit arising from the differential between the relatively high cost of diesel, and the relatively low cost of natural gas, as well as from the fairly high level of conservation education and outreach and portfolio level costs within the non-NGV EEC portfolio for which the Companies do not count any energy savings.

213.2 Please provide Table 2-1 with the NGV program, the fuel switching program and any other load building programs removed. Please specify which programs have been removed.

Response:

The following programs have been removed from the table 2-1 above:

1. All NGV programs in FEI; and
2. Other Fuel Switching programs in FEI and FEVI

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	4,932	5,212	10,144	148,607	1,294,482	0.9
FEVI	721	946	1,667	25,592	201,559	0.8
Total	**5,653**	**6,158**	**11,811**	**174,199**	**1,496,041**	**0.8**

It can be seen from the table above that NGV and other fuel switching are strong contributors to the overall portfolio TRC. The overall portfolio TRC drops from 1.1 to 0.8 when the high-carbon fuel switching programs are removed from the overall portfolio TRC. This results from the benefit arising from the differential between the relatively high cost of diesel and fuel oil/propane, and the relatively low cost of natural gas, as well as from the fairly high level of conservation education and outreach and portfolio level costs within the non-NGV EEC portfolio for which the Companies do not count any energy savings.

213.3 On page 9 the FEU state "these results comply with program principles and meet most of the requirements for adequacy in the DSM Regulation." What requirements in the DSM Regulation are not met?

Response:

In 2010, the Companies did not have an education program for students enrolled in post-secondary institutions in the FEU's service territory (clause 3 (d) of the DSM Regulation). The Companies are currently considering various options for an education program for post-secondary students, and such a program will be rolled out over the course of 2011. All other requirements for adequacy in the DSM Regulation were met.

213.4 Please provide a breakdown of all EEC incentives greater than $100,000 that have been given to customers since 2009. Specify the customer, the date and the program under which the incentive was given. If the recipient is a participant in any of FEU regulated programs or any other Fortis projects such as Biomethane, CNG, NGV, Thermal or other unregulated business, please describe.

Response:

The table below shows all incentives equal to or greater than $100,000 that have been provided to customers since 2009.

			Incentives	
Customer Name	**Year**	**Project/Program**	**Committed ($000's)**	**Paid ($000's)**
School District 23 - Central Okanagan	2010	CNGV	363	182
Waste Management Inc.	2010	CNGV	804	804
Vedder Transport	2010	LNGV	4393	2197
School District 23 - Central Okanagan	2010	Thermal System Upgrade - Pilot	100	0
Ministry of Citizen's Services	2010	PSECA	106	0
School District 72 - Campbell River	2010	PSECA	188	0

"Committed" means that a commitment has been made to a customer for an incentive amount; "paid" means that the customer has received the incentive payment. The difference could be due to a number of reasons. In the case of NGV projects, the program participant receives 50 percent of the vehicle incremental capital cost incentive upon placing the vehicle order, and the remaining 50 percent once the vehicle goes into service. In the case of PSECA ("Public Sector Energy Conservation Agreement") projects, the incentive is not paid until the Energy Savings

Measures are implemented by the customer. Also under the PSECA program, FEI is working with Delta School District to put together a thermal energy services package for this customer. EEC incentives will likely form part of this package; however the incentive amount has not yet been finalized so is not included in this table. The incentive has not yet been paid on the pilot Thermal System Upgrade project.

While the IR refers to "other unregulated businesses," the FEU note that Biomethane, NGV fueling stations, and Thermal Energy Services are regulated businesses.

213.5 Please describe the policies, procedures in place to ensure that EEC funding is distributed in a fair and equitable manner. Include a description of any committee that oversees the distribution of funds and any internal controls used to perform this oversight role.

Response:

In the Companies' original EEC Application submitted in May 2008, the FEU put forward a number of EEC Program Principles in Section 5 of the Application. Principle 1 is excerpted in its entirety below:

> *"Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative."*

The Companies' goal is to ensure that all its customers have access to some form of EEC program within the overall EEC portfolio of activity; the portfolio of programs is presented to the EEC Stakeholder group for their input and feedback, and is also presented in the EEC Annual Report. These two Commission-approved accountability mechanisms offer a method by which stakeholders can ensure that EEC funds are distributed appropriately between program activities and customer groups.

Internally, all EEC programs have business cases and budget projections associated with them, and these are approved in accordance with the Companies' financial approval levels. The Companies' EEC activity is reviewed annually by the FEU's Internal Audit ("IA") group, and the IA report for 2010 is attached as Appendix J to Appendix K-4 to Exhibit B-1. IA specifically reviews program activity to ensure that applications are approved consistent with the terms and conditions for any particular program. Customers need to be aware that a program is available, then they must implement the energy efficiency measure that the program is designed to support, then they must apply to the program. All customers that comply with the terms and conditions of any program are eligible for the program, and incentives are paid out in accordance with the terms and conditions of the various programs in the marketplace. Incentives are typically paid out to the participating customer, though incentives can also be paid out to members of the supply chain for energy efficiency upgrades, such as the $50 paid to gas contractors/dealers in the Energy Efficiency Residential Hot Water Storage Tank Program described in Section 3.4.2.1 of Appendix K-4 of the Application (Exhibit B-1). Terms and conditions for all programs are posted on the Companies' web page.

It should be emphasized that all customers that comply with the terms and conditions for any particular program are eligible for, and will receive, an incentive under that program, regardless of their choice of supplier. For example, BC Housing, who use Amaresco as their energy services company, has received many thousands of dollars in Efficient Boiler Program incentives over recent years.

214.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, Table 2-2, p.7 and pp. 8-9

FEI-FEVI 2010 EEC Report – Residential Programs

"The reasons why the Conventional EEC portfolio for FEI had a TRC level of 0.9 include the complex environment in which the Companies were operating the EEC initiatives in 2010, the relatively low gas prices, and the increase in enabling activities that do not necessarily contribute to energy saving."

214.1 Please explain why enabling activities, which are listed separately in Table 2-2, affect the TRC calculation for residential programs.

Response:

The costs incurred through Enabling Activities are not incorporated within the TRC calculation for the Residential Program area as Enabling Activities are deemed to be activities that support the Companies' overall portfolio of EEC program development and delivery. Expenditures in the area of Enabling Activities are part of the overall overhead of EEC program delivery, and are included at the portfolio level in the overall EEC portfolio TRC score only. In Table 2-2 of the 2010 EEC Annual Report, expenditures incurred through the Enabling Activities area have been captured under Portfolio Level Activities.

215.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-4, pp.127-141, and Appendix K-1, p. 7

FEI-FEVI 2010 EEC Report – Joint Initiatives

215.1 Table 7-2 of the 2010 EEC Report shows total Joint Initiative expenditures of $456,000 but Table 2-2 of the Report shows funding of $29,000 for Incentives and $429,000 for non-incentives (total $458,000). Which is the correct figure?

Response:

The discrepancy between the Joint Initiatives total in Table 7-2 and Table 2-2 is primarily due to rounding. The value of $456,000 in Table 7-2 is more precise in that it was calculated prior to rounding up to the nearest $1,000. In comparing individual inputs between the tables, the only variance is in FEVI non-program administration expenses. The precise value in Table 2-2 is $7,591 which was rounded to $9,000 in error in Table 2-2. This variance has no impact on the program area TRC.

215.2 At pages 129-30 of the 2010 EEC Report, the FEU states that the Companies made a total contribution of over $760,000 to LiveSmartBC home energy assessments from August 2009 to March 2010. Please specify in which program area these expenditures are captured. Are they included in Table 7-2?

Response:

The FEU's $760,000 contribution to LiveSmartBC home energy assessments represents combined 2009 and 2010 investments as outlined in Table 7.4. Only the 2010 contribution of $360,000 is included in Table 7.2 as a line item for LiveSmartBC Home Energy Assessments. Although these expenditures are customer subsidies, they are considered non-incentive expenditures in TRC calculations, because they do not result in direct energy savings but rather represent an avenue to further savings as homeowners undertake energy efficient retrofits.

Fiscal year differences between the FEU, BC Hydro and the provincial government presents challenges in program reporting. Provincial and BC Hydro programs are based on an April 1 to March 31 fiscal while the FEU´s reporting is based on January 1 to December 31. In preparing the EEC report, participant counts and energy savings are recorded within the year that invoices are paid. Since provincial program dates straddle the FEU´s fiscal period, in order to provide an overview of program to date contribution, it may be necessary to provide data from two different partner fiscal years.

215.3 At page 7 of Appendix K-1, the FEU states its proposed budget in 2012 and 2013 reflects the consolidation of Joint Initiatives with Residential activity. Does this mean that the requested $9.5 million for Residential activities includes funding for Joint Initiatives? Please specify the amount of Joint Initiative Funding that will consolidated into the Residential Program area.

Response:

Two-thirds of the requested $9.5 Million is for programs targeting residential customers including the following areas that were formerly included in the Joint Initiatives program area:

- $5 Million for government and utility collaborations on home energy retrofit initiatives including the current LiveSmartBC iteration, capacity building for weatherization, funding for trades engagement strategies and retrofit opportunities with municipalities.
- $100,000 to support the ongoing maintenance and increased functionally for the Home Energy Efficiency Portal and One Stop Rebate Shop
- $525,000 to support ENERGY STAR® washers, low flow shower heads, and hot water conservation strategies with electric utility partners
- $1 Million for the EnerGuide 80 and Beyond New Home Construction program in collaboration with BCHydro's PowerSmart New Homes program. Collaborate with NRCan, the provincial government and utilities on evaluation and pilots for the introduction of Near Net Zero ready homes for 2020. Educate homeowners about the benefits (energy and non-energy benefits) of efficient homes.
- In addition, collaborate with FortisBC Inc. PowerSense team on energy efficiency programs and outreach activities in our shared service territory.

In summary, $6.625 Million of the requested $9.5 Million is for programs targeting residential customers will involve collaborations with governments and utility partners.

215.4 For all the Joint Initiative Programs, please provide a breakdown of the total incentive received by the customer, the contributors to the incentives and the amounts they contributed, the total energy savings from the program and the attribution of savings to each utility or partner. For example, Table 7-5 shows the LiveSmartBC 2010 Results for Building Envelope Incentives. Please extend this table to show the total funding for the program, broken down by funding source (i.e. the FEU, BC Hydro, the Province and any other funders), the total incentive received by a customer, broken down by contribution amount, energy savings (in the appropriate units) and energy savings claimed by the each of the partners. Please complete this for every Joint Incentive program.

Response:

Since the FEU do not have access to granular information about exact amounts of actual partner contributions, the following section outlines the savings and contributions for 2010 FEU Joint Initiative programs including the LiveSmartBC 2010 iteration, the Energy and Water Efficient Appliance Program with FortisBC, and the Water Saver program with Fortis BC. Each of these programs will outline the following:

- Total incentive received by the customer
- The incentive broken down by the contributing partners
- Total forecasted energy savings for FEU
- Total forecasted contribution by FEU
- How the energy savings will be attributed for each partner

1. LiveSmartBC April 1,2010-through March 31, 2011

The following table outlines the customer incentive and the contribution made by the utility partners and Ministry of Energy and Mines through LiveSmartBC. The measures listed are the building envelope measures for which the FEU provide funding.

The FEU pay these rebates for any customers in their service territory where natural gas is the primary heat source as identified in the data provided by NRCan with fuel source equal to "natural gas" at the time of the pre-retrofit Home Energy Assessment ("D-Visit"). The electric utilities, BCHydro and Fortis BC ("FBC"), pay these rebates for any customers in their respective service territory where electricity is the primary heat source as identified in the data provided by NRCan with fuel source equal to "electric" at the time of the pre-retrofit Home Energy

Assessment ("D-Visit"). In summary, the FEU capture energy savings for homes whose primary heating source is natural gas while BCHydro and FBC capture energy savings for homes whose primary heating source is electricity.

The total incentive received by the customer and the FEU contribution to this incentive is provided in the following table.

LiveSmart BC Building Envelope Incentives for April 1, 2010 through March 31, 2011						
Building Envelope Measure Supported by FEU		LiveSmart BC Contribution		Utility Contribution	Customer Incentive	
		South Coastal	Interior & Northern	Fortis Energy Inc. Rebate	Interior and Northern	South Coastal
Air Tightness: Perform Air Sealing of the Home to Achieve:	Base Target + 20%	$50	$80	$200	$280	$250
	Base Target + 10%	$50	$75	$100	$175	$150
	Base Target	$100	$125	$0	$125	$100
Attic Insulation	Existing R-12. Upgrades to achieve a minimum of R-50	-$10	$110	$200	$310	$190
	Existing R-12. Upgrades to achieve a minimum of R-40	-$10	$70	$150	$220	$140
	Existing R-13 -R25. Upgrades to achieve a minimum of R-50	-$5	$35	$75	$110	$70
	Existing R-13-R-25. Upgrades to achieve a minimum of R-40	$0	$20	$50	$70	$50
Increase Cathedral or Flat Roof Insulation	Existing 0. Upgrade to achieve a minimum of R-14	$170	$340	$250	$590	$420
	Existing R-1 – R-12. Upgrade to achieve a minimum of R-28	-$10	$50	$100	$150	$90
	Existing R-13 – R-35. Upgrade to achieve a minimum of R-50	$50	$50	$0	$50	$50
Exterior Wall Insulation	Add at least R-9 for 100% of building to achieve a minimum of R-12	$150	$150	$250	$400	$400
	Add at least R-9 for 80% of building to achieve a minimum of R-12	$30	$30	$200	$230	$230
	Add at least R-9 for 60% of building to achieve a minimum of R-12	$0	$0	$160	$160	$160
	Add at least R-3.8 for 100% of building to achieve a minimum of R-12	$15	$15	$125	$140	$140
	Add at least R-3.8 for 80% of building to achieve a minimum of R-12	$0	$0	$100	$100	$100
Basement Insulation	Add at least R-23 for 100% of surface area	$100	$200	$300	$500	$400
	Add at least R-23 for 80% of surface area	$100	$190	$200	$390	$300
	Add at least R-23 for 60% of surface area	-$10	$40	$150	$190	$140
	Add at least R-10 for 100% of surface area	-$20	$60	$250	$310	$230
	Add at least R-10 for 80% of surface area	$0	$70	$150	$220	$150
	Add at least R-10 for 60% of surface area	-$5	$45	$125	$170	$120
Basement Header	Add at least R-20	$0	$10	$50	$60	$50
Crawl Space Wall	Add at least R-23	$170	$370	$150	$520	$320
	Add at least R-10	$0	$0	$100	$100	$100
Floor Above Crawl Space	Add at least R-24	$170	$370	$150	$520	$320
Exposed Floor	Add at least R-20 (150 sq ft minimum)	$50	$130	$100	$230	$150
Energy Star Windows	One Zone Up	$0	$10	$30	$40	$30
	Same Zone	$20	$30	$0	$30	$20

As copied from the FEU's 2010 EEC Report – Table 7-5 provides an estimate of the FEU contribution and energy savings estimates for the LiveSmartBC offer launched April 1, 2010. Only one invoice has been received to date representing approximately 25 percent of the FEU total contribution according to the Ministry of Energy and Mines. This annual forecast was prepared for budgetary purposes, economic modeling and inclusion in the 2011 projected portfolio TRC. The FEU's final program contribution and energy savings will be presented in the 2011 EEC report.

2010 EEC Report – Table 7-5

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	2,156	531	85	21,463	234,273	12%	1.1
FEVI	108	27	15	1,075	11,731	12%	1.0
TOTAL	2,264	557	100	25,609	246,004	12%	1.1

Note: The forecasted participant counts and savings are an estimate since there is a time lag between data transfer from service organizations, NRCan and the Ministry invoicing utilities. Only one invoice has been received to date for an estimated 25% of the activity. This invoice amount was multiplied by 4 to provide the above forecast.

The FEU do not have access to the contribution or savings estimates for the other program partners. Based on program participation to date, the FEU contributes about 70-75 per cent, BCHydro provides 20-25 per cent, and FBC provides about 5 per cent of the total utility contribution.

Energy savings from these measures are only attributed to one utility partner based on the customer's primary heating source so there is no need to allocate savings between utilities. Attribution of savings between the FEU and the Ministry of Energy and Mines is under discussion with consideration that the utility claims the energy savings and the Province claims the GHG emission reductions.

2. Energy and Water Efficient Appliance Program with Fortis BC

As copied from the FEU's 2010 EEC Report, Table 7-7 provides an estimate of the FEU contribution and energy savings estimates for the ENERGY STAR® washer rebate program. A $50 incentive was provided for customers who purchased select washers. The FEU paid the incentive and captured the energy savings for customers with natural gas water heating systems. FortisBC Inc. paid the incentive and captured the energy savings for customers with electric water heating systems.

2010 EEC Report – Table 7-7

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	130	7		210	2,801	10%	0.8

3. Water Savers Pilot with Fortis BC

As copied from the FEU's 2010 EEC Report, Table 7-9 provides an estimate of the FEU contribution and energy savings estimates for the water savers pilot where kits containing low flow shower heads were distributed to the communities of Castlegar and Kaleden.

The FEU provided funding and captured the energy savings for customers with natural gas water heating systems.FBC paid the incentive and captured the energy savings for customers with electric water heating systems

2010 EEC Report – Table 7-9

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/Yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	500	7	7	420	2,899	16%	2.0

215.4.1 How is the attribution of the savings determined?

Response:

For Joint Initiatives program the attributions of savings is as follows:

LiveSmartBC

- The FEU pay the incentives and capture the energy savings for all homes in their service territory flagged as natural gas primary heating source in the NRCan file completed by Certified Energy Auditors at the pre-retrofit home energy assessment. The electric utilities pay the incentives and capture the energy savings for all homes in their respective territories flagged as electricity as their primary heating source.
- Although the matter is still under discussion, the FEU will claim energy savings and the Ministry of Energy and Mines will capture the GHG emission reductions for co-funded building envelope incentives.

Energy and Water Efficient Appliance Programs (ie ENERGY STAR Tier 3 Washer rebates with electric partners)

- The FEU pay the incentives and capture the energy savings for homes with natural gas water heating systems. The electric utilities pay the incentives and capture the energy savings for homes with natural gas water heating systems.
- In addition to water heating savings, there may be electric savings associated with these efficient appliances which are captured by the electric utility.

Water Saver Programs – Low flow shower heads

- The FEU pay the incentives and capture the energy savings for homes with natural gas water heating systems. The electric utilities pay the incentives and capture the energy savings for homes with natural gas water heating systems.

215.4.2 Is the free ridership rate the same for all partners involved? For example, in the ENERGYSTAR washers program did BC Hydro and the FEU use the same free rider rate?

Response:

Yes, wherever possible the partners utilize the same free rider rate since the most common determination is market penetration of the new efficient technology. As each program is rolled out, the FEU will determine if under certain circumstances, there is a need for a free rider rate that is specific to natural gas customers.

215.5 Will all the FEU's EEC programs be accessible through the Home Efficiency Web Portal? If not, why not?

Response:

Yes. All of the FEU programs will be accessible through the Home Efficiency Web Portal. The most critical element of the Home Efficiency Web Portal for Phase I will be the database of home energy efficiency rebates for the Province of British Columbia. As such, all the offers from the FEU, electric utilities and in time, municipalities, will be represented in this database. At this time, go-to-market requirements for the web portal are being developed through interviews with stakeholders.

215.6 Please describe funding increases planned for Joint Initiatives in 2012 and 2013. Please specify the programs to which these increased budgets would be applied.

Response:

The funding requirements for Joint Initiative programs targeting residential customers outlined in BCUC IR 1.215.4 will remain relatively stable for 2012 to 2013. The collaborative initiatives for home retrofits, of which the LiveSmartBC contribution is the largest component, is the most difficult to forecast in terms of participant uptake. However, the FEU believe that a budget of $5 Million should be sufficient to cover any new collaborative initiatives envisioned for a 2013 launch.

216.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-4, pp.142-162

FEI-FEVI 2010 EEC Report – Conservation, Education and Outreach Programs

216.1 Please explain how the Energy Champion activities in Table 8-2 offered at the BC Lions and Vancouver Canucks games, other than the kids answering an energy conservation related question, educate people on energy conservation?

Response:

Table 8-2 lists the Summary of 2010 CEO Costs. Table 8-3, however, provides a Summary of the CEO Energy Champion Promotions. The partnerships with the BC Lions and Vancouver Canucks consist of a variety of energy conservation campaigns and activities implemented throughout the sporting season and school year, not solely in-game activations. Some activities are implemented at multiple games, while others are implemented once during the sporting season on an assigned game night. The BC Lions also deliver Energy Champion School Assembly Presentations at 75 elementary schools each spring throughout BC which is detailed in Section 8.2.4.2 of the 2010 EEC Report. In addition to encouraging kids to answer an energy conservation related question, in Table 8-3, a "sweater activity" is noted for both the BC Lions and Vancouver Canucks activations. For the BC Lions, the sweater relay competition educates the audience at every home game about wearing a sweater to save on heat energy instead of turning up the heat through a fun and entertaining in game promotion. For the Vancouver Canucks, the message is the same and the campaign is to encourage an online photo competition of fans wearing their "ugly sweater" to conserve energy; this was a limited time campaign during the hockey season. Another Vancouver Canucks campaign, that was accidentally omitted in Table 8-3, but was included in Table 8-4 Web Analytics Comparing Various 2010 Energy Champion Promotions, was the online Energy All Star Promotion. The promotion encouraged participants to answer a series of behavioural conservation commitments using an online tool, licensed from The Pembina Institute, educating participants on their potential energy savings based on their commitments.

In addition, a 0:30 second videos promoting energy conservation were played at various games throughout the BC Lions and Vancouver Canucks respective seasons. Finally, on assigned game nights for both the BC Lions and Vancouver Canucks, the outreach team was also in attendance interacting with the audience on energy conservation trivia.

It is important when building message retention to use multiple media channels, such as online, an in game activation, on site presence, and offsite presentations in schools to reach the audience with an energy conservation message. Leveraging on the BC Lions and Vancouver

Canucks use of mass media channels has been advantageous for CEO promotions, especially since the Companies have executed few, and limited, mass media energy conservation campaigns.

216.2 Please breakdown the funding provided for Behaviour Change programs in 2010 and 2011.

Response:

The breakdown of funding for Behaviour Change programs in 2010 and 2011 is presented in the table below:

Summary of Behaviour Change Programs Funding 2010 Actuals and 2011 Projected

Behaviour Program	2010 Actuals (000's)	2011 Projected (000's)	Total (000's)
Destination Conservation for Public Buildings Pilot Program	$16	$15	$31
Health Authority Staff Engagement Pilot	93	250	343
BC Housing Tenant Engagement Pilot	N/A	30	30
Total	$109	$265	$404

216.2.1 What research did the FEU conduct or review before designing and implementing the Destination Conservation for Public Buildings Pilot and the Health Authority Staff Engagement Pilot?

Response:

In the Destination Conservation for Public Buildings Pilot, the participating organizations conducted attitudinal and behavioural surveys of the staff. Elements Society, which designed and implemented the program, incorporated the recommendations arising from the responses into the program design, and which the FEU reviewed.

In designing and implementing the Health Authority Staff Engagement Pilot, the FEU had a combination of a research study, such as the Vancouver Coastal Health staff survey, Community Based Social Marketing principles on behaviour change, and case studies on workplace engagement and online tool engagement programs to review before designing and implementing the Engagement Pilot.

The Vancouver Coastal Health Authority initially conducted an internal staff survey to identify barriers to behavioural change. Results from the survey were included as part of the program design, which was reviewed by the FEU.

In addition, much of the program design drew from Community Based Social Marketing (CBSM) principles, introduced by environmental psychologist Doug McKenzie-Mohr, which serves as a best practices model for behaviour change programs. CBSM emphasizes on identifying barriers to adopting a particular behaviour, making commitments/pledges, developing social norms within the community, using prompts as a reminder, and rewarding positive behaviour with incentives. BC Hydro, FortisBC Inc., and Natural Resources Canada are examples of other organizations that use CBSM principles in their behaviour program design.

Finally, during the 2008 BC Hydro PowerSmart Forum, there were 2 presentations that provided a case study for the Engagement Pilot from Vancouver Island Health Authority and Vancity. Vancouver Island Health Authority's presentation, *Environmentally Responsible Approach to Health Care*, discussed the launch of their conservation focused intranet site, while Vancity presented on the successes of their "Cut the Carbon" campaign, which was an employee conservation program with an online community site as the foundation of the program.

216.2.2 Is MVS Consulting planning, implementing and running the Destination Conservation for Public Buildings Pilot?

Response:

No, MVS Consulting is not planning, implementing and running the Destination Conservation for Public Buildings Pilot. The program is run by Elements Society (formerly Pacific Resource Conservation Society), which also runs the Destination Conservation school program which FEU is currently supporting. MVS Consulting was the consultant hired by Elements Society to perform the energy assessments of municipal facilities and set the baseline of energy consumption.

216.2.3 What is the FEU's evaluation plan for the Destination Conservation for Public Buildings Pilot?

Response:

FEU's evaluation plan for the Destination Conservation for Public Buildings Pilot is to analyze the pre and post billing consumption data for the participating organizations and also survey and interview participants on the pilot program as it was a new program.

216.2.4 Are the Behavioural Change programs being offered in partnership with all the utilities in BC? If not, why not? Has the FEU considered offering these programs through LiveSmartBC?

Response:

No, not all of the Behavioural Change programs are currently offered in partnership with all the utilities in BC. The Destination Conservation for Public Buildings is one program the Companies are co-funding with FortisBC Inc.

As Behavioural Change programs are a relatively new program area within the EEC portfolio, many of the programs are still in the pilot phase. The goal of the Behavioural program is to design a successful program first with a pilot. Once the pilot is complete, launch the program to other large commercial and public organizations, and at that time, the FEU may look to including additional utility partners as part of the program.

To date, the FEU have not had discussions with, nor are opposed to working with, LiveSmartBC on developing Behavioural Change programs in the future.

216.2.4.1 Are the FEU funded programs only targeting natural gas energy conservation behaviours? If not, how can the FEU be sure that their behavioural change efforts do not duplicate the work of other utilities or the Province?

Response:

Yes, the FEU funded programs target natural gas conservation behaviours. If another utility or partner is co-funding the program, the Companies work together to ensure there is not overlap or duplication of included behaviours.

Examples of targeted natural gas behaviours in the FEU funded programs:

- In the Destination Conservation for Public Buildings Pilot Program, Okanagan College, one of the participating organizations, focuses on modifying staff behaviours to ensure that controls are utilized to turn specific rooms and buildings on campus to "sleep mode" when not in use to reduce energy consumption.
- As part of the Health Authority Staff Engagement Pilot Program online community site, the site encourages staff to make commitments, such as, using a low-flow showerhead and turning down the thermostat to conserve energy.
- BC Housing Tenant Engagement Pilot Program aims to reduce heat and hot water usage and is educating tenants on taking shorter showers and closing windows when the heat is on.

216.3 Please describe funding increases planned for CEO programs in 2012 and 2013. Please specify the programs to which these increased budgets would be applied.

Response:

The 2012 and 2013 CEO budget is intended to continue funding for, and extending to additional customers, existing CEO programs as described in Section 8 of the 2010 EEC Report, and also to develop a new education campaign on energy efficiency literacy.

Since 2009, the CEO program area had begun developing new residential, commercial, and school programs, which took some time to design and implement to the marketplace. The foundation for many of the programs has now been established in several areas, while other new areas require further development. Long term programs in the marketplace also create a stable environment to build and improve upon the previous year's program.

Residential and general public education and outreach events will continue in 2012 and 2013. A growing area will be building Home Efficiency Measures Partnerships. In 2011, pilot programs have launched with the District of Saanich and Sears Canada to distribute efficient, low-cost fixtures to residential customers to achieve energy savings. The increase in the CEO budget would allow for multiple partnerships to disseminate the program to other municipalities, big box retailers, and students through school programs.

Behaviour Programs will be an increasingly growing area as large commercial customers, including municipalities, will continue to look for low cost behaviour adjustments in their efforts to reduce energy costs within their facilities. Should pilot programs such as, the Destination Conservation for Public Buildings Pilot and/or Health Authority Staff Engagement Pilot programs prove to be successful, the Companies would offer similar programs to other large commercial or municipal customers. In addition, the 2012 and 2013 budgets would allow for funding multifamily behaviour change programs, like that of the BC Housing Tenant Engagement Pilot, or coinciding with EEC Commercial multifamily energy efficiency retrofit programs. Furthermore, increased funding would also allow Energy Specialists in launching a behaviour program at their respective organizations, supporting their efforts to educate staff and further reduce energy consumption in facilities.

School programs will also continue to expand in the CEO program area, with additional programs and schools participating in those programs. Similar to municipalities, school districts have strong interest in conservation programs, but have minimal funding to pursue them. An increase in 2012 and 2013 funding would allow additional schools to participate in the programs, such as Destination Conservation, and also develop new programs for high school and post secondary students. Consistent funding for schools programs would allow teachers and administrators to build on the previous year's successes and improve planning for future school programming.

A new addition to the CEO area that has arisen is the need for a mass education campaign on natural gas conservation and energy literacy. Through speaking with attendees at outreach events, it has become apparent that greater education is required to educate residential, including multifamily customers, on understanding why energy efficiency is important within the Province's energy picture, as well as, on energy literacy. An energy literacy campaign would educate customers on topics such as: the differences in energy efficiency ratings (eg. AFUE and Energy Factor), rating percentages, and efficiency labeling (eg. Energy Star, EnerChoice, and EnerGuide).

Mass media would be one aspect of such an initiative. Mass media refers collectively to all media technologies, including the internet, television, newspapers, radio, and other advertising which are used in a campaign. The benefits of utilizing a mix of mass media as part of an overall education campaign include cost effectiveness in reaching all customers, message retention due to stronger frequency, and informing customers on complex information through an appropriate medium. 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. Using a mix of mass media would in fact, supplement EEC programs and messaging when they are received and support the development of a culture of conservation in BC.

217.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, pp.221-225

FEI-FEVI 2010 EEC Report – Enabling Activities

217.1 Parts 11.2.4 and 11.3 of the Report describe how the FEU has funded energy solutions managers in each major service territory and has developed a pilot to fund energy specialist positions in large commercial customers. The total expenditures in this program in 2010 were $460,000 and are planned to increase to $1.684 million in 2011. Do other jurisdictions employ specific EEC or DSM managers who are focused on sales activities dedicated to increasing participation in EEC programs? Please specify.

Response:

Yes; the practice of having positions focussed on sales activities dedicated to increasing participation in EEC programs is quite common. 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.

217.1.1 Do the energy solutions managers target all customer classes or focus on a specific class?

Response:

The Energy Solutions Managers are targeting all commercial customers, with a focus on larger customers, although they have done work directly with some Rate Schedule 2 customers to assist those customers with entry into the Companies' commercial EEC programs.

217.2 Please explain why the FEU chose to fund energy specialist positions with customers that already have established BC Hydro-funded energy managers. Why did the FEU not train the existing BC Hydro-funded energy managers in natural gas DSM measures? What would the cost of training the managers have been versus funding new positions?

Response:

The Energy Specialist pilot program was developed and deployed in close collaboration with BC Hydro. For the FEU pilot program, Energy Specialists have been placed at organizations where the BC Hydro-funded Energy Manager did not have the capacity to take on natural gas DSM measures in addition to their other electricity-related projects required under the BC Hydro Energy Manager program. This lack of capacity caused a need for an additional individual to work on natural gas DSM measures. In addition, given that it is a BC Hydro directed program, there was concern from FEU that the Energy Managers would continue to focus their efforts on primarily pursuing electricity DSM solutions if a co-funding approach was taken versus funding a separate position. Due to this lack of capacity on the part of the BC Hydro-funded Energy Managers to take on natural gas DSM measures and the entrenched focus on electricity DSM solutions, the FEU in close collaboration with BC Hydro made a decision to fund a pilot program to place FEU-funded, natural gas focussed Energy Specialists in some organizations where BC Hydro-funded Energy Managers are already in place.

FEU chose to fund Energy Specialist positions with customers that already have established BC Hydro-funded Energy Managers in order to take advantage of opportunities where established energy management practice was already in place. This would enable the Energy Specialist to learn from the established Energy Manager and act on energy saving project development/implementation rather than spending a majority of their time on change management.

217.2.1 Please provide a list of the 20 customers who were approved for energy specialist positions in 2010 and a detailed breakdown of the estimated energy savings associated with the position being implemented in each customer.

Response:

The following organizations were approved for Energy Specialist positions as part of the Energy Specialist Pilot Program in 2010:

	Approved Organizations	# of Energy Specialist Positions Filled in 2010
1	BC Apartment Owners & Managers Association	0
2	BC Housing	1
3	British Columbia Institute of Technology	1
4	Cadillac Fairview	1
5	Capilano University	1
6	City of Richmond	1
7	City of Vancouver	0
8	District of North Vancouver	1
9	Fraser Health Authority	0
10	Harmony Group	1
11	Interior Health Authority	0
12	Northern Health Authority	1
13	School District #37 (Delta)	1
14	School District #38 (Richmond)	1
15	School District #41 (Burnaby)	1
16	School District #43 (Coquitlam)	0
17	Simon Fraser University	0
18	University of BC	1
19	Vancouver Coastal Health Authority	0
20	Vancouver Island Health Authority	1

Note that some of the organizations who were not able to fill their Energy Specialist positions in 2010 have filled them in 2011.

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. However, as part of the pilot program, the FEU is investigating ways to credit Energy Specialists directly for their contribution to attaining energy savings for their respective organizations.

217.2.2 If the energy specialist program is a pilot, are there plans to phase out the positions once DSM measures are implemented? If not, until when does the FEU expect to fund these positions?

Response:

The FEU's intent is to continue to fund Energy Specialist positions to the extent that the Energy Specialists can show that they are producing results in line with the Energy Specialist program's goals and objectives, and have future natural gas DSM projects to work on. Currently, the FEU sign one-year funding agreements with participating Energy Specialist Program organizations. Prior to renewing these one-year agreements, Energy Specialists are asked to provide a project plan for the following year. The FEU review the Energy Specialist's quarterly reports to date as well as this project plan to determine if continued funding is warranted. If it is apparent that there are no further natural gas DSM measures to implement at the organization then the FEU will discontinue funding for that Energy Specialist position.

217.3 Part 11.2.1.4 of the 2010 EEC Report identifies two key barriers to contractors' involvement/participation in EEC incentive programs discovered in the Contractor study. Please describe the specific changes the FEU is making to its EEC programs to address these barriers. Please reference the page numbers where these changes are included in the 2010 EEC Report.

Response:

Building strong relationships with trade allies is vital in influencing market transformation around the adoption of new, efficient technologies. Customers seek input from natural gas contractors when making purchase decisions about energy efficient products and services. Therefore, trade allies are well-positioned to provide a delivery pathway for our EEC programs by encouraging customers to install high-efficiency appliances.

Through our Contractor Program, we forge and reinforce relationships with trade allies by first understanding, then addressing barriers such as those identified in the Contractor Study. The specific changes the FEU is making to its EEC programs to address the two key barriers to contractors' involvement/participation in EEC programs identified in the Contractor Study are described below. It should be noted that the contractors targeted for the Contractor study are those that deal primarily with residential and some small commercial customers.

Key barrier #1

> *'…rewards do not compensate sufficiently for the time and energy invested – both the added un-billable time with the customer and extra time doing unpopular program application paperwork.'*

The FEU have taken steps to introduce incentives to contractor/dealers participating in programs to help offset this increased cost/burden. Examples include:

- A $50 rebate cheque is available to the contractor/dealer as an incentive to promote the Energy Efficient Residential Hot Water Storage Tank Program (described on page 30 of the Report).
- The EnerChoice Fireplace Program was re-launched on June 1 and includes a $50 rebate for the contractor/dealer. (Section 3.4.2.2.2, pages 36 and 37 of the Report, describes 2010 program results and includes discussion on considering a 'dealer incentive in the next iteration of the program.')

These are both residential programs. Further steps will be taken to address this barrier as existing programs are refined and new programs developed.

Key barrier #2

> *'…reluctance to promote something that is constantly changing for fear they will disclose the wrong information.'*

Steps taken to address this include:

- "Developing and launching a Home Energy Efficiency online portal that will provide a One Stop Rebate Shop, and information and tools that promote home energy efficiency retrofits" (excerpt from page 131 of the Report).

  This will enable contractors to direct their customers to a single source of the most current rebates available in their area.
- Quarterly contractor newsletter announces program updates.
- Develop an email database so program updates can be sent easily and efficiently.
- Include contractor incentives where it makes sense to do so in new program launches.

Through the Contractor Program, ongoing dialogue with contractors will allow the FEU to continuously improve our communications in order to address barriers to their engagement. From a larger perspective, securing long-term EEC funding that will allow programs to be in-market with certainty for longer periods of time will also help to resolve this particular barrier.

217.4 Please provide a list of all appliance standards that relate to the FEU's EEC activities and the date of implementation of the standard. For those standards which are still under development or have been finalized but not yet implemented, what is the expected date of implementation?

Response:

The following is a list of the Codes and Standards that relate to the Companies Energy Efficiency and Conservation programs. As new programs are developed additional Codes and Standards will be added to the monitoring list.

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
CSA P.2-07 – Testing method for measuring the annual utilization efficiency of residential gas-fired furnaces and boilers.	July 2008	BC Gov (MEMPR) Energy Efficiency Act. Natural Resources Canada (NRCan) Office of Energy efficiency (OEE)	Residential furnaces and boilers	Light Commercial ENERGY STAR Boiler Program. Furnace (or fireplace) TLC program.	This Performance standard falls under the guidance of the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment (TC on EE). The TC on EE is working to include consistent minimum and premium efficiency performance levels.
CSA P.3-04 Testing method for Measuring Energy Consumption and Determining Efficiencies of Gas-Fired Storage Water Heaters.	March 2006	BC Gov (MEMPR) Energy Efficiency Act. Natural Resources Canada (NRCan) Office of Energy efficiency (OEE)	Residential gas storage water heaters	Efficient residential storage tank water heater program	This Performance standard falls under the guidance of the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment (TC on EE). The TC on EE is working to include consistent minimum and premium efficiency performance levels.

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
CSA Plus 1200 Guide to energy efficiency compliance, verification, and ratings for water heaters.	March 2008		Residential water heaters: oil, gas and electric storage and gas instantaneous	Efficient residential storage tank water heater program	This a process that any industry stakeholder can use to challenge the Manufacturer's stated efficiency rating of any appliance
CSA P.4.1 Testing method for measuring annual fireplace efficiency	March 2009	BC Provincial Energy Efficiency Act and City of Vancouver Charter	Gas Fireplaces	EnerChoice Fireplace Program (top 25 % of each of the three classes of fireplace). Furnace (or fireplace) TLC program.	This Performance standard falls under the guidance of the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment (TC on EE). The TC on EE is working to include consistent minimum and premium efficiency performance levels.
ANSI Z21.10.3/CSA 4.3-2011 Gas Water Heaters – Volume III, Storage Water Heaters With Input Ratings Above 75,000 Btu Per Hour, Circulating and Instantaneous.	2011	Natural Resources Canada (NRCan) Office of Energy efficiency (OEE)	Commercial water heaters	Efficient Commercial Water Heater Program	Canada and USA energy efficiency testing protocol

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
ANSI Z21.13a-2010/CSA 4.9a-2010 – Gas-fired low pressure steam and hot water boilers.	2010	Natural Resources Canada (NRCan) Office of Energy efficiency (OEE)	Commercial hot water boilers	Efficient Boiler Program. Efficient Commercial Water Heater Program.	Canada and USA energy efficiency testing protocol
BTS 2000 Testing Standard for Efficiency of Commercial Space-heating Boilers, Hydronics Institute Division of AHRI	2000	Department of Energy (DOE)	Commercial space heating boilers	Efficient Boiler Program	USA manufacturers testing standard
CSA P.7-09 – Test method for measuring energy loss of gas-fired instantaneous water heaters	February 2010	Natural Resources Canada (NRCan) Office of Energy efficiency (OEE)	Gas on-demand (instantaneous) water heaters	Efficient Commercial Water Heater Program	This Performance standard falls under the guidance of the CSA Technical Committee on Energy Efficiency and Related Performance of Fuel-Burning Appliances and Equipment (TC on EE). The TC on EE is working to include consistent minimum and premium efficiency performance levels.
CSA F379 Packaged solar domestic hot water systems (liquid-to-liquid heat transfer)	January 2009	BC Government, Building and Safety Policy Branch.	Solar systems	Solar Thermal hot water rebate (city of Vancouver)	This standard covers safety of potable water and other design issues of solar systems utilizing single and double wall heat exchangers

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
CSA F383 Installation of packaged solar domestic hot water systems.	October 2008	BC Government, Building and Safety Policy Branch.	Solar systems	Solar Thermal hot water rebate (city of Vancouver)	This standard covers installation procedures for solar systems
BC Building Code, Part 7: Plumbing Services	2006	BC Government, Building and Safety Policy Branch.	Solar systems	Solar Thermal hot water rebate (city of Vancouver)	This code covers back flow prevention aspects of solar systems

Natural Gas Vehicle Codes

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
ANSI NGV3.1 Fuel System Components for Natural Gas Powered Vehicles	1995	BC Safety Authority	Compressed Natural Gas Vehicles	Innovative Technologies NGV	This standard is applicable to all CNG vehicle conversion applications
CGA C-6.4-1998 Methods for External Inspection of natural Gas Vehicle Fuel Containers and Their Installations	2008	BC Safety Authority	Compressed Natural Gas Vehicles	Innovative Technologies NGV	Technical committee being reconvened

Code or Standard	Effective Dates	Regulatory Authority	Application	Associated EEC Program(s)	Comments
CSA Z276-01 Liquefied Natural Gas (LNG) - Production, Storage, and Handling	November 2001	BC Safety Authority. Oil and Gas Commission.	Liquefied Natural Gas (LNG) Vehicles and refueling stations	Innovative Technologies NGV	Oil and Gas Commission is proposing an expansion of this standard to include LNG fueling facilities

Codes under development

British Columbia Building Code Parts 3, 6, 9, and 10	Expected September 2012	BC Government, Building and Safety Policy Branch. Individual municipality bylaws	Building Code	Commercial and residential new construction	Far reaching changes to energy efficiency levels of new construction will have a large impact on new construction energy consumption and program design concentrating on heat loss of building enclosure
Minimum Equipment Performance Standard for Domestic Water Heaters	Potentially 2020	Natural Resources Canada	Domestic Water Heaters	0.80 EF Hot Water Heater Pilot	The federal government has indicated that they will be requiring residential water heaters to have a minimum 0.80 EF in 2020. There is currently no storage-type equipment available that is residentially sized that meets this requirement

Note: Where Canadian Codes are expired or do not exist Nation Fire Protection Association (NFPA) or International Standards Organization (ISO) standards are usually specified by regulatory authorities.

217.4.1 Which of the FEU's EEC programs are reaching maturity?

Response:

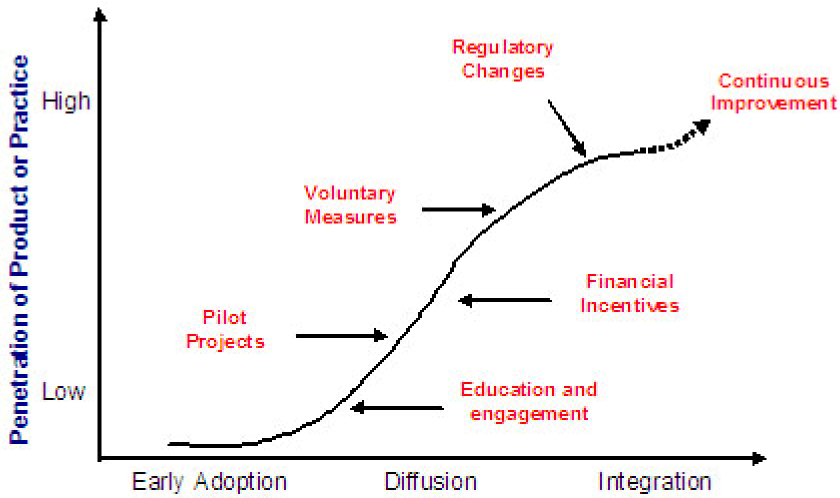
At this time, none of the programs that the FEU have in-market are reaching maturity. All of the equipment incentive programs are required in order to support potential future regulations. As regulations are implemented, incentives will be reviewed and phased out as required. In some instances, the implementation of a regulation does not necessarily result in a rise in general baseline equipment efficiency in the marketplace. A case in point is residential furnaces. The minimum equipment performance standard for furnaces is 90 percent, however the Companies' Residential End Use Survey found that almost 80 percent of the furnaces in the FEU's service territory were low- or mid-efficient, leading the Companies to put forward the "Furnace Scrap-It" program outlined in Section 4.1 of Appendix K to Exhibit B-1.

217.4.2 On page 266 of Appendix K-4, the FEU states their EEC programs have market transformation as their ultimate goal. Please describe the FEU's plans to phase out EEC programs as the market transforms.

Response:

The market transformation curve is shown below.[81]

[81] Source: http://www.greenplaybook.org/strategic/innovation/policy_levers/articles129.htm



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 noted in the response to BCUC IR 1.217.4.1. The Companies will monitor equipment saturation levels where possible, and survey customers, to determine whether a particular piece of efficient equipment requires an incentive or not.

217.5 At page 233 of the 2010 EEC Report the FEU states "[t]hese conventional DSM protocols significantly limit a utility's ability to offer effective incentives on products with regulated minimum efficiency levels, as the energy savings on which incentives are based are small…Yet limiting a utility's ability to offer effective incentives ignores marketplace realities… It is the Companies' intention to pursue such a program as part of the suite of EEC offerings for 2012 and 2013 that will be brought forward in the Revenue Requirements Application to be filed in May 2011." In the Furnace Scrap-it Program is the FEU counting energy savings according to conventional DSM protocols? If not, why not? If not, please compare the energy savings the FEU is projecting versus those calculated under conventional DSM protocols.

Response:

Energy savings for the Scrap-it program are calculated according to normal DSM protocols. The detailed analysis is provided as part of the response to BCUC IR 1.189.2. The only aspect of the energy savings flow from this program that is different than most programs is that, through a proactive replacement decision, higher energy savings are delivered in the early years (prior to the failure of the installed furnace) and lower savings in later years when the customer would have had to install a minimum code furnace.

217.6 Given that the Furnace Scrap-it Program fails the conventional TRC test, what parameters of the proposed Societal Cost Test are necessary for the program to pass?

Response:

The TRC of the Scrap-it program is 0.56, while for the SCT the result is 1.18. All proposed parameters for the SCT are needed for this program to pass. Details of the impacts of SCT parameters are included in the response to BCUC IR 1.189.2.

217.6.1 What level of incentive would the FEU offer, under conventional DSM protocols, for the Furnace Scrap-it Program to pass the TRC?

Response:

Incentive levels are a transfer payment between the utility and the customer[82], and do not affect either the TRC or the SCT. The "cost" side of the TRC and SCT is driven by the incremental cost of the measure and non-incentive program costs. The incentive reduces the incremental cost to the program participant, and increases utility incentive cost but has no effect on the overall benefit/cost analysis of the program using the TRC/SCT.

217.6.1.1 What level of participation does the FEU estimate with this level of incentive?

[82] California Standard Practice Manual, 2001, p. 21

Response:

Since the Furnace Scrap-It Program is still in developmental stages, market research and consultation with industry partners have not yet been conducted to determine the optimal incentive levels that would most effectively drive participation. The FEU participation estimate of 8,500 per year for each of the two years was selected to align with the savings potential in the Conservation Potential Review and to align with the $10 Million proposed budget for the project. Based on the past ENERGY STAR heating system upgrade program participation, it is not unreasonable to assume that 8,500 participants can be achieved. The 2008 REUS study indicates that over 17 percent of FEU customers have heating systems that are over 25 years old, so 8500 upgrades is a relatively small percentage. Based on the FEU's estimate of 560,000 furnaces that are standard to mid efficiency, 8,500 would only represent 1.5 percent of the stock requiring upgrading.

The estimated level of incentive of $1,000 per customer and a small incentive of $100 for the contractor is used to develop preliminary modeling for cost benefit analysis and at this point is provided for discussion purposes only.

217.7 Please describe funding increases planned for Enabling Activities in 2012 and 2013. Please specify the programs to which these increased budgets would be applied.

Response:

There are no separate, specific funding budget increases requested for Enabling Activities in 2012 and 2013. The 2012 and 2013 EEC plans have not yet been developed, so the Companies are not in a position to specify the program areas in which Enabling Activity would expand, nor to specify portfolio-level Enabling Activity. However, it is expected that enabling activity in 2012 and 2013 would continue in the areas established in 2011; namely, Research and Evaluation, working with Efficiency Partners, Codes and Standards and Energy Management.

218.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, pp.260-263

FEI-FEVI 2010 EEC Report – Data Gathering Reporting and Internal Control Processes

218.1 Please describe the FEU's measurement and verification processes for the energy savings from their EEC programs.

<u>Response:</u>

Please see response to BCUC IR 1.195.1 and 1.212.2.