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British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

**Attention: Erica M. Hamilton,
Commission Secretary**

Dear Sirs/Mesdames:

Re: An Application by FortisBC Energy Utilities [Comprising FortisBC Energy Inc., FortisBC Energy Inc., Fort Nelson Service Area, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.] 2012 and 2013 Revenue Requirements and Natural Gas Rates

We enclose for filing in the above proceeding the electronic version of the Submission on behalf of FortisBC Energy Utilities.

Twelve hard copies of the Submission will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Matthew Ghikas]

Matthew Ghikas

MTG/ccm
Encl.

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BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*, R.S.B.C. 1996, CHAPTER 473

AND

An Application by FortisBC Energy Utilities

[COMPRISING FORTISBC ENERGY INC., FORTISBC ENERGY INC., FORT NELSON SERVICE AREA, FORTISBC ENERGY (WHISTLER) INC., AND FORTISBC ENERGY (VANCOUVER ISLAND) INC.]

2012 AND 2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES

SUBMISSION OF FORTISBC ENERGY UTILITIES

December 2, 2011

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PART ONE: INTRODUCTION AND OVERVIEW

A. INTRODUCTION

1. In this Application, the FortisBC Energy Utilities ("FEU" or "Companies"), comprising FortisBC Energy Inc. (FEI), the Fort Nelson Service Area of FEI ("Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEW"), are applying for:

- approval of natural gas delivery rates for 2012 and 2013, and related rate approvals, pursuant to sections 59-61 of the *Utilities Commission Act* ("UCA"); and
- acceptance of an expenditure schedule for Energy Efficiency and Conservation ("EEC") activity for 2012 and 2013, pursuant to section 44.2 of the UCA.

Attached to this Submission is a copy of an updated Draft Order, which sets out the approvals sought in greater detail.[1] As accounted for in the Draft Order, upon receipt of the Commission's decision the FEU can file updated financial schedules with the 2012 opening balances of FEU's net plant-in-service and rate base deferral accounts for the purpose of setting 2012-2013 rates.

(a) Proposed Delivery Rates

2. FEI and FEW are seeking delivery rate increases totaling just under 12% over the two-year test period. The proposed two-year rate increase in Ft. Nelson is 1.3%. FEVI rates will remain at 2011 levels through the test period. In the case of FEI and Fort Nelson, the increases are driven in large measure by previously approved commitments and projects going into service, as well as updated depreciation rates determined under the guidance of an external

[1] The FEU note that the original Draft Order in the Application had been revised in the Evidentiary Update, Exhibit B-21, to reflect changes made up to that time. Notable changes included: (1) the proposed rates for Fort Nelson; and (2) the withdrawal of the requested approval of an amalgamated cost of service for the reasons articulated in the Companies' letter submitted on August 30, 2011, marked as Exhibit B-19. A further revised Draft Order was filed as Exhibit B-41 (Undertaking No. 15), which had been revised to include the change in treatment sought for the Biomethane Variance Account. The version attached to this Submission is further updated to reflect changes discussed in this Submission based on subsequent evidence at the hearing.

expert. The proposed delivery rate increase for FEW is mainly the product of a decline in throughput.

3. The FEU have undertaken a thorough review of their costs to ensure that the requested rates reflect business requirements and initiatives that must or should proceed in the test period and are in the interest of customers. The budgets reflected in the Application were developed and approved internally through established processes that involve significant executive oversight; the budgets have also been scrutinized in this proceeding. The FEU submit, for the reasons articulated in this Submission, that the evidence confirms that the proposed rates are just and reasonable. They should be approved as sought.

(b) Proposed EEC Expenditures

4. The other main aspect of this Application is the Companies' request for acceptance of an expenditure schedule in the amount of $64.5 million in each of 2012 and 2013 to support ongoing cost-effective EEC activity in the Program Areas described in the evidence. The EEC activity contemplated will help qualifying customers reduce their total energy costs and can confer other non-energy benefits.

5. The requested funding envelope consists of two components:

- First, base funding of $15 million[2] will be reflected in 2012 and 2013 rates, and represents a continuation of the level of funding actually spent in 2011; and

- Second, additional amounts spent above the base amount up to the funding envelope accrue on an as-spent basis only, to be recovered from customers starting in 2014.

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[2] As discussed below in *Part Eleven: Energy Efficiency and Conservation*, the FEU believe it would be reasonable to include only $15 million in rate base for 2012 and 2013, rather than the original proposal of $20 million. The revised figure is consistent with the most recent 2011 projections of EEC spending. This $5 million reduction is not reflected in the current rate proposals.

This financial treatment ensures that a reasonable amount of EEC costs are reflected in 2012-2013 rates, while removing the forecast risk for customers associated with incremental EEC activity.

6. The total amount of activity that the FEU can pursue within the overall funding envelope will depend on the cost-effectiveness screen employed. The three new Program Areas (Furnace Scrap-it, Solar Thermal and Thermal Energy for Schools), representing a total of $25 million of the overall envelope each year, can only proceed based on a cost-effectiveness test (e.g. the Societal Cost Test ("SCT")) that recognizes non-energy benefits that the currently-approved Total Resource Cost ("TRC") test does not recognize. The FEU will adhere to whatever test is adopted, and ensure that the overall portfolio remains cost-effective. EEC activities undertaken are subject to Commission oversight and will be reviewed with stakeholders according to the established review mechanisms.

7. The FEU submit that the proposed financial treatment, the overall envelope of EEC activity, the proposed SCT, and the existing oversight mechanisms, are appropriate for the reasons described in this Submission. The expenditure schedule should be accepted as proposed.

B. OVERVIEW OF RATES AND DRIVERS

8. In this section, we set the context for the Application, summarize the delivery rate change required by the utilities, and also summarize the evidence regarding key drivers of rates in each case.

(a) The Application in Context

9. John Walker, the President and Chief Executive Officer of the FEU, began the oral hearing with an Opening Statement that set the context for how the Companies approached this Application, which is the FEU's first revenue requirements application under his leadership.

Among other things, Mr. Walker stressed that the shareholder's interest is best served in the long-term by ensuring that customers are satisfied.[3]

10. Mr. Walker identified a number of customer-focused initiatives which have affected the revenue requirements in 2012-2013, some by requiring investment and others by reducing the revenue requirements.[4] In particular:

- The Customer Care Enhancement ("CCE") Project, approved in 2010, provides the FEU with direct control over the customer relationship, and provides added flexibility to offer new services to customers and local employees that will put greater emphasis on customer service. As the CCE project is going in to service on January 1, 2012, the costs of the project are reflected in rates during the test period.

- EEC provides financial incentives and education that help customers better understand their energy options and manage their energy costs, while reducing GHG emissions. A portion of the cost of past EEC activities (as-spent) is being recovered in the 2012-2013 test period. The proposed base EEC spending of $15 million per year will also affect rates during the test period. Actual spending above the 2012 and 2013 base will be recovered commencing in 2014.[5]

- The adoption of combined leadership under the FortisBC name has yielded savings to date in the form of reduced executive compensation costs.[6] The combined leadership will provide the platform to look at potential savings

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3 Walker: T2, p. 140, l. 13 to p. 141, l. 24.

4 Exhibit B-23. Opening Statement, p.3.

5 Based on the approved financial treatment, this means that the return on rate base and tax expense associated with the forecast mid-year balance (after-tax) of the account, including the addition of $15.0 million each year ($11.3 million on an after-tax basis), will be recovered through 2012 and 2013 rates. Further, 1/10th of the 2012 spend (or $1.1 million, after-tax) will also be recovered through 2013 rates. In addition, the FEU have requested the flexibility to spend up to an additional $49.5 million per year to target the cost-effective opportunities for energy savings that have been identified through studies performed to date. However, this spending above the base amount does not affect 2012 and 2013 rates because the proposed financial treatment involves recovering the actual spend above $15 million beginning in 2014.

6 Walker: T2, p. 187, ll. 15 to 19.

through greater integration with the electric utility. However, material savings cannot realistically be realized until after the test period.[7]

- The FEU have previously obtained approval for Biomethane service, fueling service for Natural Gas Vehicles, and thermal energy service ("TES"). These initiatives offer customers options for gas supply, provide a means to ensure that natural gas remains a fundamental part of the energy picture in British Columbia and are in line with Provincial policy. In terms of the impact on 2012 and 2013 rates:

  (A) Some investment is required in the test period to support the growth of the Biomethane service.[8]

  (B) The revenue requirement is reduced when NGV throughput is added, but NGV customer additions depend heavily upon incentive funding at this stage of the market development. Although the Commission's NGV-EEC Decision, which resulted in the suspension of NGV EEC activity, has caused a reduction in forecast revenues, the NGV revenue will still reduce overall cost of service for natural gas customers.[9]

  (C) The allocation of thermal energy overheads from the natural gas class of service to the thermal energy class of service in 2012 and 2013 reduces the natural gas revenue requirement by $500,000 per year.[10]

11. Mr. Walker expressed his conviction that "[i]n a future characterized by increasing energy choices, customers will choose to do business with us because we are

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[7] Walker: T2, p. 170, l. 9 to p. 172, l. 21 and T2, p. 187, l. 19 to p. 188, l. 3.

[8] Exhibit B-1. Appendix J.

[9] Exhibit B-21. Evidentiary Update, September 12, 2011

[10] Discussed in Part Eight, Section E of this Submission.

providing energy safely, reliably, cost-effectively and sustainably, and communicating with them about energy options in a manner consistent with their expectations."[11] The revenue requirement drivers, discussed below, provide an indication of how the Companies intend to meet service requirements in 2012 and 2013 and position themselves to be able to continue to provide service at a level our customers expect going forward.

(b) FEI Delivery Rate Summary and Drivers

12. FEI's proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.6 per cent in 2012 and an additional effective base rate delivery increase of 6.3 per cent in 2013 (cumulative increase of 11.9 per cent). These proposed increases, along with changes to the Revenue Stabilization Account Mechanism ("RSAM") and Earnings Sharing Mechanism ("ESM") rate riders for 2012, result in a net increase in the annual bill of an average Lower Mainland residential customer of approximately 3.2 per cent or $30 in 2012 and an additional 3.2 per cent or $31 in 2013.[12]

13. The key items driving the 11.9% two-year delivery rate increase for FEI are as follows:

- Approximately 5.2 percentage points of the increase is due to costs associated with meeting Commission-approved commitments. These include the CCE Project[13] (2.2 percentage points); the Fraser River HDD[14], Kootenay River HDD[15], and Tilbury land purchase[16] CPCNs (0.5 percentage points), and other existing approved deferrals (2.5 percentage points).

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[11] Walker: T2, p. 148, ll. 12 to 17.

[12] Delivery rates are, of course, only one component of the customer's total bill. The other two components, the midstream charge and commodity costs, are reviewed through the quarterly gas cost filings (except in the case of FEVI), and not this proceeding. When delivery rates are considered together with commodity costs and midstream rates, the percentage impact on customer bills is smaller than the delivery rate percentages. Exhibit B-1, p. 71 as updated by Exhibit B-1-3.

[13] CPCN granted in Order No. C-1-10, dated February 25, 2010.

[14] CPCN granted in Order No. C-2-09, dated March 12, 2009.

[15] CPCN granted in Order No. C-9-10, dated November 10, 2010.

[16] CPCN granted in Order No. C-2-10 dated April 27, 2010.

- Approximately 2 percentage points of the increase is due to inflation, including 1 percentage point attributable to labour inflation.[17]

- Approximately 2.5 percentage points is due to required changes to depreciation rates and to properly allocate the costs to remove assets (net negative salvage).[18]

14. Mr. Walker emphasized in his Opening Statement that the FEU carefully considered requests for new funding before putting them forward, and only proposed initiatives "that we believe are important." The facts bear this out. Only approximately 2[19] percentage points of the forecast increase in FEI delivery rates over the two-year period – an increase which would translate to about a 1% bill increase on average to customers (or $10) – is attributable to new spending. Much of this new spending is required to comply with changes in codes and regulations and to assess priorities for addressing aging system assets. The new spending also includes the cost of service related to FEI's portion of the $15 million per year of EEC expenditures. It also includes the funding required to pursue traditional natural gas load as well as continue to undertake initiatives like Biomethane and NGV. The evidence demonstrates that these initiatives, and the remainder of the new spending comprising the 2 percentage points of the rate increase, are in the interest of customers.

(c) FEVI Delivery Rate Summary and Drivers

15. FEVI is proposing to continue existing delivery rates for sales customers and the two transport customers without contractual rates (FEW and BC Hydro).[20] The existing Rate Stabilization Deferral Account ("RSDA") is available 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 2012 cost of service is below the forecast revenues at existing rates, with

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17 Exhibit B-23, Opening Statement, p. 4.

18 Exhibit B-23, Opening Statement, p. 4.

19 This percentage is reduced slightly by the deduction in proposed EEC spending to enter rate base in 2012 and 2013 from $20 million to $15 million.

20 The rates for the Vancouver Island Gas Joint Venture and Squamish would remain the same in accordance with their respective Transportation Service Agreements.

the result that there is a forecast $6.4 million addition ($4.2 million after-tax) to the RSDA balance in 2012. There is a forecast deficiency in 2013. Of the approximate 6% increase in total revenue required, 2.3 percentage points relates to depreciation and negative salvage, 1.5 percentage points relates to projects and deferrals that the Commission has approved (i.e. the CCE Project, Mount Hayes LNG Storage Facility Project and the Victoria Regional Operations Centre[21]), approximately 0.2 percentage points relates to labour and benefits and inflation and the remaining 2 percentage points is attributable to other changes. These other changes include the loss of the royalty revenues, a decline in throughput, Long-Term Sustainment Plan requirements, and EEC deferral account additions; the combined total of which is largely offset by the decrease in gas costs and an increase in other revenue.

16. The forecast closing RSDA balance in 2012 is $59.7 million, after tax. The surplus balance in the RSDA will be used to offset the forecast revenue deficiency in 2013 (i.e. freeze rates) and results in a remaining balance of $52.5 million, after tax in 2013 available for future years.[22]

17. A rate freeze is an appropriate rate mitigation strategy for the 2012 and 2013 test period in light of the continued long-term significant upward pressure on rates for Vancouver Island customers, and continued pressure to remain competitive with other energy sources. A rate freeze for the next two years provides rate certainty for FEVI customers and will enable natural gas on Vancouver Island to remain competitive with other energy sources during that time period.[23]

(d) FEW Delivery Rate Summary and Drivers

18. FEW's proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.0 per cent in 2012 and an additional effective delivery rate increase of 6.5 per cent in 2013 (cumulative increase of 11.6 per cent).

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[21] Exhibit B-1, p. 383.

[22] Exhibit B-1, pp. 72 to 73, as updated by Exhibit B-1-3 and B-52, Undertaking No. 24.

[23] Exhibit B-1, pp. 72 to 73, as updated by Exhibit B-1-3 and B-52, Undertaking No. 24.

These proposed increases, along with changes to the RSAM rate rider for 2012, result in a net increase in the annual bill of an average Whistler residential customer of 6.5 per cent or $96 in 2012 and an additional 4.3 per cent or $64 in 2013.[24]

19. FEW's rate increase is primarily the product of declines in throughput from large general service customers, not new spending. Given FEW's small customer base, relatively small differences in the use per customer can have a significant impact on delivery rates in percentage terms. In 2012 and 2013 the forecast total throughput is approximately 48 TJs and 55 TJs lower than the demand forecast embedded in 2011 rates and accounts for approximately 7.5 percentage points of the cumulative 11.6 per cent increase.[25]

(e) Fort Nelson Delivery Rate Summary and Drivers

20. The FEU had initially proposed an effective delivery rate decrease of 6.7 per cent in 2012, followed by an effective base rate delivery increase of 15.0 per cent in 2013 (cumulative increase of 8.3 per cent).[26] However, Ms. Roy identified at the hearing that this swing in rates could be avoided by holding 2012 delivery rates at 2011 levels and then, by way of a deferral account, using the revenue surplus to offset the rate increase in 2013.[27] This would result in a 2013 delivery rate increase of only 1.3 percent.[28] Ms. Roy's proposed approach is preferable as it stabilizes rates for customers of Fort Nelson.

21. The increase in 2013 is primarily due to a single system integrity project, Muskwa River Crossing, going into service. The Commission accepted an expenditure schedule for the Muskwa River Crossing project in Order No. G-27-11. Given the small customer base in Fort

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24 Exhibit B-1, p. 71 as updated by Exhibit B-1-3.

25 Exhibit B-1, p. 62 as updated by Exhibit B-1-3 and Exhibit B-21, September 12th Evidentiary Update, Section 7, Tab 7.3, Schedules 1 and 3; 7.5 per cent impact calculated as total customer additions and use rate changes of $574.9 thousand / $7,639 thousand margin at existing rates

26 Exhibit B-1, p. 71 as updated by Exhibit B-1-3.

27 Roy: T2, p. 274, l. 6 to l. 22.

28 Exhibit B-66, Cover Letter to Fort Nelson Revised Financial Schedules.

Nelson, a relatively small capital project of this nature[29] still has a notable delivery rate impact. O&M expense increases of $62 thousand in 2012 and $23 thousand in 2013 are attributable to the Service Standards and Reliability cost driver.[30]

C. THE BREADTH AND DEPTH OF EVIDENCE

22. This section provides a high level overview of the nature of the evidence in the written record and the witnesses who appeared at the hearing. The FEU prepared a comprehensive application, provided responsive answers to detailed information requests, and updated information where appropriate. The witnesses were prepared to address the wide variety of subjects canvassed at the oral hearing. The result of these efforts is an extensive evidentiary record that supports the orders sought.

(a) The Application and Written Record

23. The Application[31] includes information regarding the FEU's management structure, performance on Service Quality Indicators since 2003, compensation management, capital and operations and maintenance (O&M) forecasting processes, and natural gas demand and revenue forecasting. It also provides a detailed account of cost of service and calculation of rate base for 2012 and 2013, including a description of and accounting for each existing and proposed deferral account and complete financial schedules for each utility. The FEU's proposed depreciation and negative salvage rates are supported by the Depreciation Study by Gannett Fleming and the EEC portfolio by the Conservation Potential Review by ICF Marbek.

24. The Application explains every forecast incremental O&M expenditure exceeding $100,000, broken down by department and by category of cost driver. The cost drivers are useful in explaining changes in O&M levels since 2010, and highlight the impacts of changing

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[29] Exhibit B-1-3, revised p. 358 of the Application. Total project costs for this option are currently estimated at $3.1 million (excluding AFUDC). Of this total, approximately $3.0 million will be added to rate base in late 2012, with the remainder being added in 2013.

[30] Exhibit B-1, pp. 66 to 67 as updated by Exhibit B-1-3.

[31] Exhibits B-1 and B-1-1, as updated by Exhibits B-1-2, B-1-3 and B-1-4.

circumstances.[32] The FEU provided both an activity-based and a resource-based view of costs at the level of detail required by Commission Order No. G-153-07.[33] The activity-based view permits analysis of how costs had evolved over time.[34]

25. The further breakdown by organizational department at the lowest level cost element and lowest level activity code, on a comparable basis for the test period and prior years as far back as 2006, which was sought by Staff, was not available because the FEU had maintained its records in accordance with the Commission's previous determination.[35] The FEU submit that the level of detail required under the currently-approved framework remains appropriate going forward for the following reasons:

- Mr. Thomson cautioned that there is a cost associated with providing additional granularity.[36]
- Ms. Roy indicated that, as there were roughly 79 cost centres, applications would be almost incomprehensible at the level of detail requested by staff.[37]
- Ms. Roy observed that the current approach allows meaningful comparisons of how costs have evolved over time. Moving to greater granularity results in the greater number of changes within the numbers, and "it just becomes more of a reclassification exercise, when every explanation you're having is changed because these people used to be over here, but now they're over there."[38]

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[32] The five cost drivers are Labour Inflation and Benefits, Codes and Regulations, Customer and Stakeholder Expectations, Demographics, and Service Standards and Reliability. Exhibit B-17, BCUC IR 2.23.1.

[33] Roy and Thomson: T5, p. 662, l. 5 to p. 663, l. 24; Order No. G-127-04 granted a variance from the code of accounts.

[34] Roy: T5, p. 668, ll. 5 to 16.

[35] Exhibit B-17, BCUC IR 2.12.4. Mr. Thomson also observed that when the Commission had issued Order No. G-124-07 regarding the level of information provided, it made the decision with the benefit of examples of the level of information that would be provided. The information provided in this Application is consistent. Thomson: T5, p. 666, l. 23 to p. 667, l. 16.

[36] Thomson: T5, p. 667, ll. 12-16.

[37] Roy: T5, p. 667, l. 17 to p. 668, l. 16.

[38] Roy: T5, p. 668, ll. 5-16. T5, p. 663, l. 15 to p. 665, l. 30; Exhibit B-17, BCUC IR 2.12.4.

In light of the cost and questionable benefit of the cost centre-by-cost centre presentation, the FEU submit that the Commission should uphold its initial decision on the appropriate level of detail to be included in future revenue requirements applications.

26. The FEU filed two Evidentiary Updates, one on July 19th and the second on September 12th, which incorporated a number of material developments.

- The July 19th Evidentiary Update[39] incorporated (a) the impacts of Commission Order No. G-117-11, which approved the adoption of US GAAP, (b) the most recent short-term interest rate forecast, (c) an update to the timing and cost estimate of the Fort Nelson Muskwa River Project, and (d) a revision to the forecast cost of gas for FEVI.
- The September 12th Evidentiary Update[40] incorporated the impacts of (a) Commission Order G-128-11 regarding FEI's Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Service Application and Order G-145-11 regarding NGV-EEC incentives, (b) a change to the timing and cost of FEI's Kootenay River Crossing Project, (c) an estimate of the AES Inquiry costs, and a deferral account proposal for those costs, and (d) an update to the 2011 FEI capital expenditure projection.

In order to facilitate a review of the Application with these changes, the FEU filed replacement pages to the Application in Exhibits B-1-3 and B-1-4.

27. There were two rounds of information requests on the Application, followed by a third round on the 2012-2013 EEC Plan filed in rebuttal to the evidence of BCSEA's expert, Mr. Plunkett. In total, the FEU responded to over 1600 information requests. With the exception of a handful of information requests relating to the AES Inquiry and specific thermal energy

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[39] Exhibit B-11. The Evidentiary Update also made corrections to the financial schedules that were identified in responding the first round of IRs. The change in deficiency was largely attributable to only one error; the FEU had duplicated the interest formula for a 2011 debt issue, resulting in understated expense for 2011. The remaining corrections were presentation issues only (e.g., due to rows inadvertently hidden in spread sheets).

[40] Exhibit B-21.

projects that were not relevant to this Application, the FEU provided complete and thorough responses.

28. As a result, the parties proceeded to the oral hearing with an extensive written record already established.

(b) FEU Witnesses at the Hearing

29. The oral hearing lasted eight days, the bulk of which was devoted to cross-examination of the FEU's witnesses. Seven of the 10 members of the FEU executive testified during the hearing, including the President and CEO, Mr. Walker.[41] These executives sit on the Executive Leadership Team ("ELT"), which (as discussed in Part Two) oversaw the budgeting process. Four of the remaining six witnesses are members of the Utilities Operating Committee ("UOC"), which (as discussed in Part Two) guided the development of the departmental budgets.[42] Ms. Smith is responsible for managing EEC programs and Mr. Kennedy is the depreciation expert retained by the FEU. Collectively, the witnesses represented the key players in the determination of the revenue requirements. The broad representation on the panels reflected the Companies' commitment to transparency in the determination of 2012-2013 delivery rates.

D. ORGANIZATION OF THIS SUBMISSION

30. This Submission addresses the FEU's requested orders and evidence in support. A significant portion of this Submission is devoted to addressing the wide variety of topics that were pursued in information requests and at the hearing. The bulk of these topics were pursued only by Commission Staff, who do not file submissions identifying those matters that they still consider to be unresolved. As a result, the FEU expect that there are some topics

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[41] Exhibit B-23. The executives were: John Walker, President and CEO; Scott Thomson, Executive Vice President, Finance, Regulatory and Energy Supply; Roger Dall'Antonia, Vice President, Finance & CFO; Cynthia Des Brisay, Vice President, Energy Supply and Resource Development; Doug Stout, Vice President, Energy Solutions & External Relations; Dwain Bell, Vice President of Operations (Gas); and, Tom Loski, Vice President of Customer Service.

[42] Diane Roy is the Director of Regulatory Affairs; David Bennett is Director of Resource Planning and Market Development; Jody Drope is Chief Human Resources Officer; and, David Legge is Chief Information Officer.

canvassed in this submission that are no longer live issues, but we have discussed them out of an abundance of caution. The FEU will provide focused reply submissions in response to specific matters raised by intervenors in argument.

31. The Submission is organized as follows:

(a) *Part Two: Management of Costs and Rate Determination* explains the process that the FEU undertook to calculate the impacts of past investments and to prepare budgets for 2012 and 2013.

(b) *Part Three: Demand Forecast and Revenues at Existing Rates* explains the FEU's established method for forecasting demand for natural gas, including customer additions and the use per customer.

(c) *Part Four: Cost of Service: FEVI's Cost of Gas* explains the forecast of the cost of gas, which is relevant only to FEVI's rates.

(d) *Part Five: Cost of Service: Operations and Maintenance (O&M) Expense* explains the components of the O&M budget, including incremental expenses on a department basis.

(e) *Part Six: Cost of Service: Depreciation and Amortization* addresses the FEU's proposed depreciation and negative salvage rates as well as the proper treatment of negative salvage and asset losses.

(f) *Part Seven: Cost of Service: Other Factors* addresses, CIAC, other revenue, taxes, financing costs and return on equity and the reduction to overhead through the allocation to the Thermal Energy Service class of service.

(g) *Part Eight: Capital Expenditures* addresses the categories of capital expenditures forecasts and related issues explored during the hearing.

(h) *Part Nine: Deferral Accounts* addresses the issues explored during the hearing related to deferral accounts.

(i) *Part Ten: Rate Base – Issues Raised* discusses three rate base issues raised during the hearing including the Olympic Cauldron, main extensions, and the LNG tankers and mobile LNG fueling station.

(j) *Part Eleven: Energy Efficiency and Conservation* discusses the FEU's proposed EEC expenditures, including existing and new Program Areas, and EEC-related approvals sought.

(k) *Part Twelve: Conclusion*.

PART TWO: MANAGEMENT OF COSTS AND RATE DETERMINATION

A. INTRODUCTION

32. In developing the RRA, the FEU relied on an established budgeting process that incorporated significant management oversight from the FEU's recently integrated management team. In this Part, we outline the evidence on:

- the budgeting process;
- the independence of the budgeting process from the Balanced Scorecard approach used to assess performance and at-risk compensation;
- the ongoing benefits of savings achieved during PBR; and
- trends that demonstrate that the FEU have successfully managed costs.

The FEU submit that the evidence described below demonstrates that an appropriate and accountable management structure is in place. The budgeting process undertaken by the Companies supports the reasonableness of the forecasts upon which the proposed rates are based.

B. DIRECTION AND OVERSIGHT OF BUDGETING PROCESS

33. The FEU's management structure is outlined in section 3.1.1 of the Application. The FEU's ELT is ultimately responsible for utility management and budgeting, which is done through the UOC at the operational level.

34. The ELT, comprised of the President and Vice Presidents, is directly responsible for providing overall leadership and strategic guidance. Under the combined leadership structure, as before, the ELT provides the strategic direction for the Companies and develops the business plan in support, including the setting of the performance targets. The ELT works closely with, and guides, the UOC to ensure that business goals and objectives are achieved.[43]

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[43] Exhibit B-1, p. 30.

35. The UOC is comprised of senior managers representing the different departments within the Companies.[44] The UOC reviews and approves capital budgets, including all information technology projects, develops O&M budgets, and monitors and manages actual O&M expenditures during the year.[45]

36. Mr. Walker, who is directly involved in the budgeting process via his position on ELT, testified to the dedication of the management team in managing costs of the business. He stated, for example:

> …we constantly focus on productivity, whether we're in or out of PBR, as we drive our business forward. And again, I believe it's just a good way, if you're going to have a sustainable business, that you have to continue to focus on being better at it, and finding a way to deliver your services without just driving incremental costs. You've got to find a way to mitigate that as you go forward.[46]

The evidence of the comprehensive budgeting exercise undertaken by the FEU, discussed next, supports Mr. Walker's conviction.

C. ITERATIVE BUDGETING PROCESS: MODIFIED ZERO-BASED AND TRENDING

37. The evidence discussed below demonstrates that the capital and O&M budgets are prepared iteratively under the direction of the ELT based on practices and methodologies appropriate for the nature of particular departments and costs.

(a) Capital Budgeting Process

38. The Companies continue to manage the capital expenditures using defined capital approval policies and management processes. Capital funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that capital is put to its best use while minimizing the impact on rates.[47] The Capital Approval Policy outlines responsibilities and approval limits. It provides that annual capital budgets are

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[44] Exhibit B-1, pp. 30 to 31.

[45] Exhibit B-1, p. 39.

[46] Walker: T2, p. 190, ll. 13 to 21.

[47] Exhibit B-1, p. 38.

reviewed and approved by the UOC and the ELT. Capital projects are reviewed again before spending occurs to re-confirm the appropriateness of estimates and availability of staffing and resources.[48] Large capital projects subject to a CPCN are reviewed by the Board of Directors.[49] IT projects require approval of the UOC regardless of dollar value.[50]

39. The distribution and transmission operations are the most capital intensive areas of the business. The 2012-2013 RRA reflects the work that has been done to combine the Distribution and Transmission groups to permit more effective deployment of capital. As explained by Mr. Bell:[51]

> The efficiencies that we will find [from the reorganization of Transmission and Distribution into a single Operations department] will be in better use of capital, making sure in fact that, you know, we are utilizing the capital where it's most required. A common approach to asset management and the fact that we're going to be able to use the same criteria whether it's an intermediate pressure line on the distribution side of the business or a transmission line on the transmission side of the business, because both of those assets are regulated by the Oil and Gas Commission.

40. In summary, the capital budgets for 2012 and 2013 reviewed and approved by the UOC and the ELT are based on proven methodologies using the best known information and represent the capital spending needed to address the required safety, reliability, operational and customer requirements at a reasonable cost.[52]

(b) O&M Budgeting Process

41. Policies and processes are also in place for O&M. Two features of the O&M budgeting process were emphasized by the witnesses during the hearing:

- The budgeting process is bottom-up and iterative, rather than top-down; and

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48 Exhibit B-1, p. 39.

49 Exhibit B-1, p. 39.

50 Exhibit B-1, p. 39.

51 Bell: T7, p. 1068, ll . 7 to 16.

52 Exhibit B-1, section 6.2; Exhibit B-6, BCOAPO IR 1.10.1, 1.10.2, 1.11.1.

- The FEU employ various budgeting techniques, such as zero-based budgeting or trend-based budgeting, that reflect the nature of the work performed in specific areas of the business.

42. Mr. Walker described the iterative process and its benefits as follows:

> …But what we do do is that through -- as we move down the levels, because it's a bottom up, top down, bottom up kind of sort of iterative process that we go through, and the various functional areas, vice presidents and directors, are tasked to challenge and support at each level the resources that they need dollar-wise and people-wise to move forward with the various programs. So when they eventually get discussed at the executive table, I'm hearing from all the various departments. And what we'll get them is a sense of yeah, that'll be great to do and it's important but not right now, and we need to massage that. And that would -- the number of people that we would require to do that would follow that sort of discussion.[53]

43. The UOC reviews existing O&M budgets to ensure their appropriateness and continued justification. Incremental O&M funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that funding is put to its best use while minimizing the impact on customers' rates.[54] Mr. Dall'Antonia discussed the types of budgeting approaches employed, explaining that in areas where the levels of activity vary materially from year to year the Companies revisit the existing budget to a much greater degree. Trend-based budgeting is used to a greater extent in circumstances where the level of activity is steady and predictable year over year:

> MR. DALL'ANTONIA: A: I think Mr. Walker's comment about we don't do zero based budgeting, I think what he was referring to is a cross-organization, a true zero based, where you basically go back to first principles every year. Throughout the organization there are elements of zero-based budgeting.
>
> I think what we would call our approach is more of a hybrid approach, where trending or incremental budgeting versus zero base work together.
>
> Certain areas of our business do use more zero base budgeting because they're more activity based. Mr. Bell, when he's up here, he runs transmission and

[53] Walker: T2, p. 258, ll. 3-21.

[54] Exhibit B-1, p. 39.

distribution, which is effectively the largest component of the business. His group, he oversees the budgeting as the EP [sic - VP] of that area. They tend to do something that is much closer to zero based, where they look at activity view, they look at what projects or activities they'll undertake in the next two years versus ones they won't.

For instance, every year we have a certain budget for rights of way clearing. Some years it's higher, some years it's lower. You don't just assume that you've got a line for rights of way clearing and it just goes up with inflation. Seismic assessments, single point failure assessments, code compliance, those can vary year to year, as well as based on growth, based on system integrity planning, activity in certain areas do change. So there is an element, or a much greater element of zero base budgeting in that process.

So you look at say the finance and regulatory group, our work tends to be much more routine and constant. So you can look at individuals, you can look at specific external contracts, but it's much easier to do a trending, if you will, in those areas of the business.

Overall, the UOC, they put together a budget working group, and department managers are asked to look at their budgets from point of view of take last year's, the last number of years from an experiential point of view, see what you're not going to be doing, get to what we'd call a baseline, and then justify any increases to that. So it is a mix of what we'd call zero-based and incremental.

But again, given the fact that we've been at this for a number of years and we know our business very well, the value in going to a zero-based each year for the incremental benefit would not justify having to redo budgets at that level. If that answers the question.[55]

44. A more zero-based approach is key in activity-driven budgets to ensuring that the existing budget is still warranted. The Transmission & Distribution division has, by far, the largest budget among the divisions, and employs that zero-based approach. Mr. Bell characterized the approach as follows:

MR. BELL: A: If I can -- now, I can talk to my specific area within the organization, and we are what I would call as close to zero base budget as I think you can get. So asset management at the beginning of the budgeting process determines exactly how many units of each type they want to have surveyed or repaired or inspected during the year. We then overlay the costs for the previous period on top of that, which gives us our budget.

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[55] Dall'Antonia: T5, p.689 l. 12 to p. 691, l. 9.

> So, the only areas that have what I would call a bit of flex in are the areas of training and what I call idle time. So, idle time would be time that we don't have any construction activities or operating activities in a smaller district. And so we have people that are available for emergency response, and that's what they're there for. Or if we have -- and again in the training side of things, we have what's called mandatory training. We have to get it done during that year. But we will have programs that are not mandatory. They do give us a bit of flex. An example of that would be training a crew person who normally does service line installation or emergency repair to do meter-read calls, so that we can utilize them when a crunch hits our meter-read calls.
>
> So, there -- those two areas we budget by person and by time available. The rest of it is done with the field staff, it's done on a per-unit basis.[56]

45. Mr. Bell also explained how the centralized approach within the Operations department (the largest within the FEU) captures savings that get reflected in the divisional budget:[57]

> Our entire system is laid out in a manner that allows us to plan the work, do the work, and then complete it and review it, and so we do that on a continual basis. We almost look at that as the price of admission, I guess I would say.
>
> … Yeah, and again, I think it's probably because certainly within my group, we look at that through everything we do. As an example, when we have somebody do a valve check, that goes into our system. The costs are recorded. We have a key contact that reviews that across the province. They take the highs and the lows. They have a look at that. The reason we do that is you may have a group of people that can do a product very very low, and at the end of the day they are not completing it as per the codes or standards. And so we want to find out if they found a better way to do it, to make sure they're doing it correctly. And then same with the highs, you know, what caused it to be high, and we can review that right down to the employee level.
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> So we do spend a lot of time in this area within my group.

46. The process of revisiting the activity based budgets each year on a zero-based approach ensures that past productivity gains are passed along to customers.[58] However, the

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[56] Bell: T6, p. 986, l. 17 to p. 987, l. 19.

[57] Bell: T6, p. 984, ll. 22 to 26 and p. 985, l. 13 to p. 986, l. 3.

[58] Bell: T6, p. 984, l. 22 to l. 26, p. 985, l. 13 to p. 986, l. 3 and p. 988, l. 14 to p. 990, l. 18. Mr. Weafer, in addressing this point with Mr. Bell during cross-examination, observed that the word "productivity" only occurs 7 times in the Application: p. 985, ll. 7-12. Examples of savings and productivity improvements, however, are

FEU are able to use knowledge acquired from past years to make the budgeting process more efficient in areas where zero-based approach would add little value. Those areas include finance and regulatory,[59] and other similar areas in the Companies where costs are not as subject to variability according to individual units of work.[60] On the whole, this hybrid approach undertaken by the FEU applies the necessary rigour and is cost-effective for customers.

D. BALANCED SCORECARD INDEPENDENT OF BUDGETING ACTIVITY

47. In this section, we distinguish the Balanced Scorecard approach from the budgeting process. The Balanced Scorecard is a management tool to assess the performance of the utilities. It contains performance measures that are designed to align the interests of the shareholder, customers and employees in terms of how the utilities carry out the business.[61] As described below, the Balanced Scorecard neither acts as a substitute for, nor detracts from, the budgeting process described previously. The role of the Balanced Scorecard in determining employee compensation is addressed later in these submissions.

48. There were a number of information requests and questions in cross-examination which appeared to suggest that the Balanced Scorecard improperly motivates the FEU or the executive to "to pursue growth in O&M budgets"[62] or inflate rate base.[63] However, the Balanced Scorecard, by design, could not have that effect because the targets are not set until after the Commission's decision in the RRA.[64] The financial target in the Balanced Scorecard is concerned with the shareholder's opportunity to a fair return as approved by the Commission. The Financial category (including the target for net earnings) incorporates the approved costs and revenues that are utilized in determining customers' rates each year. For the Customer category, the O&M and Base capital amounts are the same O&M and Base

detailed throughout the Application. While word counts have questionable relevance in terms of evaluating the FEU's budgeting process, we observe that words synonymous with productivity are pervasive in the Application. Mr. Bell's evidence on the budgeting process should be preferred to word counts.

59 Dall'Antonia: T5, p. 690, ll. 16 to 21.

60 Bell: T6, p. 986, l. 17 to p. 987, l. 19.

61 Exhibit B-17, BCUC IR 2.123.5. The FEU scorecard results are provided in Exhibit B-6, BCOAPO 1.7.2.

62 Exhibit B-17, BCUC IR 2.123.6

63 Thomson: T3, p. 489, ll. 14 to 25.

64 Exhibit B-17, BCUC IR 2.123.6.

Capital amounts that are incorporated into the Commission's determination of customers' rates.[65] As such, there is no incentive under the Balanced Scorecard for management to have a larger O&M budget.[66] As explained by Mr. Thomson, regarding rate base:

> The second component of your question deals with incenting us to grow rate base. The scorecard can't by design have that effect because the targets around capital spending are established after the rates are set. They're based on what the forecast already is and has been approved. And the incentive or the reward is achieved if we're in a position to deploy capital efficiently and spend less. If we spend less, when we come back in for rates our rate base is lower, and that's a benefit to customers. So it has the exact opposite effect to what you're suggesting.[67]

49. Other questions appeared to raise the concern that the Balanced Scorecard incented the Companies to under-spend O&M and capital in order to enhance the results of the Scorecard. Under spending on O&M during the test period could enhance earnings, and could improve the results for the O&M per customer measure.[68] Reducing the rate base below what was used in the Scorecard could also generate benefits. However, the Customer scorecard measures, O&M per Customer and Base Capital, are primarily for the benefit of the customer as the measures are indicators of the FEU's success in managing and containing costs.[69] It is appropriate to incent management to spend responsibly, rather than spend for the sake of exhausting the budget.[70] Over the long term, success in these two measures serves to minimize rate increases for customers.[71] As explained by Mr. Thomson, in the case of O&M:

> There's a reward, if you will, for achieving an O&M per customer that's below the target. The score card does have a threshold and a top-out component to each of the measures. It's a fairly tight range and there's tension in the scorecard. We're not interested in setting [sic-incenting] our employees to

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65 Exhibit B-1, p. 33; Exhibit B-17, BCUC IR 2.123.4.

66 Exhibit B-17, BCUC IR 2.123.6.

67 Thomson: T3, p. 489, ll. 14 to 25.

68 The O&M per customer target incents management to be disciplined in spending and meet or come under the O&M forecasts used in the Commission-approved rates, as well as cost-effectively add new customers.

69 Exhibit B-17, BCUC IR 2.123.5.

70 This appears to be the approach advocated by Commission Counsel at T3, p. 489, l. 1 to 4.

71 Exhibit B-17, BCUC IR 2.123.5.

> unspend at the risk of service or safety, but to look for productivity enhancements, but there's a range around that.[72]

50. The same logic outlined by Mr. Thomson applies with respect to the rate base per customer measure.[73] Customers benefit from the efficient deployment of capital by way of a lower opening rate base the next time rates are set.[74] The customer satisfaction and safety metrics provide incentives to ensure the appropriate levels of capital and O&M spending are incurred to deliver an appropriate and safe level of service.[75]

51. The fact that management are incented to seek out savings while ensuring that safe and reliable service is maintained is a good thing for customers, and tracks the regulatory compact. By contrast, an approach of encouraging the FEU to spend the entire approved budget even where circumstances have evolved to give rise to opportunities to achieve savings is an excellent example of the customers "cutting off their proverbial nose to spite the shareholder's face". The better approach for customers is to accept that the Commission has thoroughly reviewed the budgets in this process and to obtain the benefits associated with efficient spending that carry over in to the next revenue requirements application.

52. There was also a series of questions in cross-examination from Commission Counsel that questioned the degree to which customers had input into the Balanced Scorecard targets. The Balanced Scorecard is a management tool for ensuring greater management alignment with business objectives, which include financial performance, safety and service quality. Customers do not and cannot manage the Companies, and thus do not need or have a right to provide direct input into the Scorecard. Customers nevertheless are involved in revenue requirements proceedings, the outcome of which determines the amounts used as financial targets. That level of involvement is appropriate.

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[72] Thomson: T3, p. 489, ll. 5 to 13.

[73] The capital spending measure provides incentive to be disciplined in the deployment of capital, which works to reduce rate base.

[74] Thomson: T3, p. 489, ll. 14 to 25.

[75] Exhibit B-17, BCUC IR 2.123.6.

53. The FEU submit that the Balanced Scorecard is an appropriate tool for assessing the performance of the utilities against Commission-approved budgets. The consistent success of the FEU in meeting its targets[76] speaks to the prudent management of the utilities to the benefit of the shareholder and customers alike.

E. PBR BENEFITS CONTINUE TO FLOW TO CUSTOMERS

54. The PBR period, which ended in 2009, brought significant benefits to customers and the shareholder consistent with its intended result. The benefits flowing from PBR continue to accrue to customers.

55. The earnings sharing benefits flowing to customers over the six years of PBR were $67.5 million. The savings were achieved through a number of means, including the Utilities Strategy Project (the adoption of combined utility management for the FEU), deferring activities and related costs where safe and prudent to do so, management of the meter to cash process resulting in the lowering of bad debts, centralized asset management in Distribution services, and department reorganization and streamlining.[77] FEI continues to see lower costs in many areas from these initiatives which are permanent in nature. However, a number of the efficiencies that were realized during PBR can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred. Savings have also been offset by changing priorities and initiatives in many other areas in response to, for instance, changes to codes and regulations, customer and stakeholder expectations, and energy policy. Capital expenditures and O&M in 2012 and 2013 are thus higher than during the PBR period.[78]

56. PBR came to a close at the end of 2009 and the FEU have been under traditional cost of service ratemaking for 2010 and 2011. Expenses related to deferred expenditures from

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[76] Exhibit B-6, BCOAPO IR 1.7.2 and 1.8.2

[77] Exhibit B-17, BCUC IR 2.2.2.

[78] Exhibit B-17, BCUC IR 2.2.2.

the PBR period were all forecast to be incurred in 2010 and no costs related to deferred savings under PBR were forecast for 2011 or beyond.[79]

F. DELIVERY RATE, O&M AND FTE TRENDS

57. Appendix D to the Application provides historical operating and maintenance expenses, a history of FTEs, historical data of the utility income and earned return, income taxes, return on capital, utility rate base, capital expenditures and customer service call volume information. The FEU submit that the broader historical view underscores the FEU's successful management of costs.

58. During the hearing, the Commission staff prepared a Witness Aid which appeared to show that FEI's delivery charges, and the FEU's employees and costs are rising significantly faster than CPI.[80] The FEU's witnesses disagreed with how the Witness Aid depicted these trends, and the FEU prepared their own graphs in response.[81] Mr. Thomson and Ms. Roy articulated a number of additional factors that must be accounted for to obtain a realistic trend line.[82] For instance:

- FEI's delivery charge graph, unlike the Witness Aid, accounts for the fact that FEI charges both a fixed and volumetric rate and that the fixed component of the rate (which has been held constant since 2010) needs to be included in the delivery charge analysis.[83] The effect of excluding the fixed component in the Witness Aid was to distort the magnitude of the rate increases since 2010, since all revenue requirement increases since 2010 were streamed to the volumetric component depicted in the Staff Witness Aid.

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79 Attached to Exhibit B-28 are various IR responses from the 2010-2011 RRA proceeding that explain this. In redirect, Mr. Bell also clarified that the impacts of the deferrals to which he referred during his testimony were accounted for in the present test period, and not 2012 or 2013.

80 Exhibit A2-2A.

81 Exhibit B-26, Undertaking No. 1.

82 Thomson: T3, p. 291, l. 18 to p. 298, l. 24.

83 Thomson: T3, p. 292, l. 4 to p. 293, l. 10.

- FEI's delivery charge has been significantly affected by a drop in throughput in the system, which had not been considered in the Staff Witness Aid.[84]

- Reflecting delivery rates, costs and employees on a per customer basis accounts for the fact that the business has grown over time. Using absolute costs, as was done in the Staff Witness Aid, distorts the picture.[85]

- FEI has also experienced accounting changes beginning in 2010, including changes in the overhead capitalized rate and the impact of changes in GAAP.[86]

59. While the FEU's graph of "Delivery Charge vs. Inflation"[87] is a more accurate depiction of the trends than the Staff Witness Aid, the real picture is still more favourable. The FEU's graph excluded labour inflation (which was filed confidentially as negotiations with bargaining units are underway). The effect of that factor would be to increase the CPI line from 15 to 16.5 percent on the first graph in Undertaking No. 1.[88] This narrows the gap between inflation and delivery margin per customer to about 2% over the period of 8 years from 2006 to 2013. Including the full PBR period (from 2003), the increase in delivery margin per customer is below CPI.

60. The FEU also prepared graphs showing "O&M and FTE vs. Inflation".[89] After adjusting for the effect of labour inflation, there was an 18.5% change in O&M per customer since 2006 vs. a 16.5% change in CPI over the same period.[90] Again, including the full PBR period (from 2003) the increase in both O&M per customer and FTEs is well below CPI. Further, O&M per customer and FTE per customer today are *well* below where they were in 1999.[91]

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[84] Thomson: T3, p. 293, ll. 11-18.

[85] Thomson: T3, p. 295, ll. 23 to 26.

[86] Roy: T3, p. 296, ll. 17 to 25.

[87] Exhibit B-26, pp. 1-2.

[88] Exhibit B-26, p. 1.

[89] Exhibit B-26, pp. 3-4.

[90] Thomson and Roy: T3, p. 296, l. 1 to 298, l. 19.

[91] Thomson: T3, p. 298, ll. 5 to 19.

61. The adjusted graphs therefore paint a very different picture than was implied by the Staff Witness Aid. They demonstrate that the FEU have successfully managed costs.[92]

62. There are valid reasons for the cost increases in 2012 and 2013, and the FEU have explained the cost drivers in the Application, IR responses and at the oral hearing. In the following Parts of this Submission, issues related to cost increases are discussed.

G. SUMMARY REGARDING MANAGEMENT OF COSTS AND RATE DETERMINATION

63. The evidence demonstrates that the FEU has appropriate processes and oversight in place to budget and manage costs. The rates sought are a product of those processes. Parts Three to Seven of this Submission set out the components of cost of service that must be recovered in the proposed rates.

[92] Exhibit B-26, Undertaking No. 1.

PART THREE: DEMAND FORECAST AND REVENUES AT EXISTING RATES

64. As a first step in determining the revenue requirement for the test period, the FEU forecasted revenue at existing rates (forecast demand multiplied by the existing rates)[93] using the same methodology that has been employed in numerous past proceedings based on up to date information.[94] The FEU are forecasting a slight increase in natural gas consumption in Mainland and Fort Nelson, a slight decrease in Vancouver Island and a larger decrease in Whistler, where consumption is forecast to decline by 1 percent from 2012 to 2013.[95] The forecast increases in throughput for FEI and Fort Nelson reduce delivery rates, all else equal. For FEVI, decreased throughput will be reflected in a reduction in the RSDA that will be returned to customers. The decline in throughput in Whistler is the primary driver of higher delivery rates for FEW in the test period.

65. The following sections demonstrate:

- The established methodology has yielded appropriate forecasts of residential and commercial customer additions;
- The forecast use per customer ("UPC") for residential and commercial customers is reasonable; and
- The FEU's practice of surveying industrial customers remains a reasonable means of forecasting industrial demand.

No material issues were raised in the IR process or at the hearing with the methodology or the calculation of revenues at existing rates. The FEU submit that the forecast natural gas demand and revenues are reasonable and should be accepted for the purposes of calculating 2012-2013 delivery rates.

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93 Bennett: T5, p. 721, ll. 12-23.

94 Exhibit B-1, p. 75; Bennett: T5, p. 740, ll. 7 to 11.

95 The FEU's demand forecast is reviewed in section 4.2, summarized in Table 4.2-1 of the Application and described in detail for each utility in sections 4.4 to 4.7. A reasonable forecast of the revenues and margins was developed using the total energy forecast applied at existing 2011 rates as described for each utility in sections 4.4 to 4.7. Further information related to the forecast is provided in Appendices C-2 and C-3 of the Application.

A. RESIDENTIAL AND COMMERCIAL DEMAND FORECASTS

66. The two main components of the residential and commercial demand forecast are (1) the forecast number of customers and customer additions, and (2) the forecast average use per customer by customer class.

(a) Forecast of Residential and Commercial Customer Additions

67. The FEU forecast of residential and commercial customer additions, unlike UPC, is an "at risk" item in the revenue requirement of FEI, Fort Nelson and FEW. For FEVI, the RSDA will capture the impact of the variance in customer additions from forecast.[96] The FEU have established methodologies for forecasting residential and customer additions that have a proven track record. This forecast is discussed in detail in the sections below.

Forecast of Residential Customer Additions

68. The FEU's established methodology for forecasting residential customer additions is based on housing starts, which show a high (90%) statistical correlation with customer additions.[97] The FEU rely on the Canadian Mortgage and Housing Corporation ("CMHC") and Conference Board of Canada ("CBOC") housing start forecast, with adjustments made based on knowledge of local markets by FEU staff.[98] One improvement that has been made to the established methodology is to forecast single family and multi-family dwellings separately, for which the FEU have different capture rates.[99]

69. As with any forecast, variances from forecast on customer additions do occur.[100] They are attributable to a number of factors, including the recession, the timing lag between housing starts and the FEU's new customers, existing customer turnover, and also the small

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96 Exhibit B-6, BCOAPO IR 1.6.2.

97 Exhibit B-1, p. 84.

98 Exhibit B-1, p. 84; Exhibit B-6, BCOAPO 1.16.2.

99 Exhibit B-1, p. 83; Bennett, T5, p. 727, l. 23 to p. 728, l. 10; T6, p. 891, l. 2 to p. 892, l. 21.

100 Exhibit B-6, BCOAPO 1.16.1 graphs the past 10 years of forecast vs. actual, demonstrating that these variances have been both favourable and unfavourable over time.

number of new customers in commercial Rate Schedules.[101] For FEW and Fort Nelson, the larger percentage variances are largely a reflection of the small number of new customers in these regions.[102] However, the evidence that customer additions track housing starts reinforces the reasonableness of relying on the CMHC and CBOC forecast of housing starts as the best available method to forecast customer additions.[103]

70. A variation in the number of customers results in a variance in throughput on the delivery system, and correspondingly, a variance in revenues. However, variances from the short-term forecast customer additions over the test period are not material to the revenue requirements for two reasons.[104] First, the number of new customers and usage from those customers is very small compared to the number of existing customers and their usage.[105] Second, this variance in revenues associated with a variance in customer additions is partly offset by the variance in the O&M and capital costs associated with those customer additions.[106] As a result, the impact of customer additions is dwarfed by the impact of weather on the much larger existing customer base.[107]

71. The forecast customer additions should be based on evidence, rather than being results-driven.[108] The FEU submit that the residential customer additions forecast should be accepted as filed.

Forecast of Commercial Customer Additions

72. The forecast of commercial customer additions is based upon an analysis of recent trends in each region and commercial rate class. This method is consistent with

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[101] Exhibit B-9, BCUC IR 1.25.3

[102] Exhibit B-9, BCUC IR 1.25.3

[103] Exhibit B-1, p. 84.

[104] Bennett: T5, p. 736, l. 22 to p. 737, l. 8.

[105] Bennett: T5, p. 736, l. 22 to p. 737, l. 3 and p. 747, ll. 9 to 17; Exhibit B-54, Undertaking No. 26.

[106] Exhibit B-6, BCOAPO IR 1.6.1, 1.19.2 and 1.19.3.

[107] Exhibit B-1, p. 88. The total residential demand is more than 5 times more sensitive to weather fluctuations than it is to the demand from new customers.

[108] Mr. Weafer's cross-examination questions for Mr. Bennett suggested that the customer additions forecast could be increased in order to reduce the revenue requirement. e.g., T5, p. 737, ll. 9 to 23.

methods employed by other utilities[109] and has provided accurate results in the past, with an average variance over the 2007 to 2010 period of 0.5%.[110] Given the small number of customers added to the commercial rate classes, the percentage variance over time shows a very high degree of accuracy.[111] There is no evidence of any alternative forecast method that would yield more accurate results.

(b) Forecast Use Per Customer Rate

73. The forecast UPC rate is the second key input into both the residential and commercial demand forecast. Again, the evidence demonstrates that the FEU's forecast methodology is sound. UPC variances, which are attributable to uncontrollable factors such as weather, are captured in deferral accounts that remove forecast risk to customers and the shareholder.[112] However, it is nonetheless important to be as accurate as possible in forecasting UPC.

74. Consistent with past practice and industry standards, the FEU base the UPC forecast on an analysis of weather-normalized consumption data to remove the impact of weather variations.[113] The steps involved in forecasting are described in the responses to IRs.[114] A detailed account of the UPC forecast for each utility and rate class is provided in section 4.4 of the Application.

75. The UPC rate is generally more predictable than the rate of customer additions and there has been limited variability in the forecast.[115] 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

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[109] Bennett: T5, p. 751, ll. 23 to 26.

[110] Exhibit B-1, pp. 85 to 86.

[111] Bennett: T5, p. 751, l. 23 to p. 752, l. 10; Exhibit B-9, BCUC IR 1.25.3. and 1.25.4.

[112] FEU residential and commercial customers, and all FEVI, FEW and Fort Nelson customers.

[113] Exhibit B-1, pp. 81 to 82. An illustration of the calculation used to produce the UPC is provided in Exhibit B-8, CEC IR 1.5.1.

[114] Exhibit B-6. BCOAPO IR 1.20.1 and 1.22.1.

[115] Bennett: T5, p. 747, ll. 18-22; T6, p. 896, ll. 11 to 14.

UPC is approximately -2 percent. The forecasting percentage 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.[116] For FEVI, FEW and Fort Nelson the average percentage variance is greater, largely due to the lower customer count in those service areas.[117]

76. The FEU have been experiencing a declining use per customer rate over the last decade, with the exception of 2009.[118] The reasons for this long-term decline are many and include the shift to more multi-family dwelling units and efficiency improvements, including as a result of the FEU's EEC programs.[119] The decline in use per customer rate is higher on Vancouver Island, as the smaller customer base means that the number of new customer additions that tend to have lower consumption represent a greater proportion of the total customers compared to FEI.[120] Consistent with this past trend, the FEU are forecasting a slight decline in the UPC rate. The forecast UPC represents a slight leveling of the UPC rate based on the changes in normalized UPC experienced in the last three years.[121] This is consistent with the general picture of UPC decline, in which the decline was steeper in the early 2000's and less steep in the later 2000's.[122] While an eventual leveling off of the UPC rate is expected in the long term, the trends analyzed by FEU and the continuation of the underlying causes of decline in UPC do not support a forecast of level UPC over the test period.[123]

77. The RSAM is a deferral mechanism that stabilizes delivery margin received from Residential and Commercial customer classes for FEI, and all customers for Fort Nelson and FEW, on a UPC basis.[124] The volume in the RSAM accounts is largely an indication of temperatures being above or below normal and may swing from positive to negative balances.

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[116] Exhibit B-9, BCUC IR 1.25.3.

[117] Exhibit B-9, BCUC IR 1.25.4.

[118] Exhibit B-17, BCUC IR 2.8.3.

[119] Exhibit B-1, p. 82; Exhibit B-9, BCUC IR 1.30.1 and 1.35.1; Exhibit B-17, BCUC IR 2.8.2; Exhibit B-8, CEC IR 1.5.4.

[120] Exhibit B-17, BCUC IR 2.9.2.

[121] Exhibit B-8, CEC IR 1.5.2.

[122] Bennett: T5, p. 742, l. 1 to 26.

[123] Exhibit B-17, BCUC IR 2.8.3.

[124] Exhibit B-1, p. 92; Exhibit B-9, BCUC IR 1.31.1 and 1.31.1.1.

Since the balance in the RSAM is refunded or charged to customers in a rate rider over three years, and is offset by the recovery or refund for each subsequent year, the balance in the RSAM generally does not accumulate.[125]

78. For FEVI, variances are captured in the broader Revenue Surplus Deferral Account (RSDA), rather than an RSAM, but the effect is the same.[126]

79. The availability of deferral mechanisms to capture the variances from forecast UPC and avoid windfalls to the shareholder or customers is not a substitute for attempting to provide as accurate a forecast as possible. As Mr. Bennett indicated in response to a question from Mr. Weafer inquiring about the ability to flatten the UPC forecast to a greater extent than forecast by the FEU: "…the use per customer rates are declining over time, it's better to put that through into rates as quickly as possible, because if you deal with through the RSAM mechanism and wait, you can have a bigger rate shock if you delayed making a decision and then do that at a later point in time."[127]

80. The FEU submit that it is appropriate to employ the established methodology to estimate UPC, rather than employ a short-term, results-driven approach to the potential longer term detriment of customers.

(c) Industrial Forecast

81. Consistent with past practice, the FEU forecasted industrial demand based on an annual demand survey requesting each industrial customer to provide its short-term forecast monthly consumption and long-term annual consumption. Recent improvements to the survey methodology have increased participation rates.[128] The survey participants accounted for

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[125] The historical RSAM volumes for FEI, FEW and For Nelson were provided in response to information requests. For FEI, these volumes are presented from 2001. Exhibit B-1, BCUC IR 1.31.1.1, and 1.31.2.

[126] Exhibit B-1, p. 105; Exhibit B-9, BCUC IR 1.31.2 Generally speaking, the RSDA is a temporary measure used to mitigate rate swings following the dissolution of the Revenue Deficiency Deferral Account and expiration of the royalty revenues from the Province on December 31, 2011.

[127] Bennett: T5, p. 746, l. 12 to 747, l.2.

[128] Exhibit B-9, BCUC IR 1.29.1. Exhibit B-6, BCOAPO IR 1.18.1 and 1.18.2.

approximately 83% of industrial demand.[129] The FEU have started a Survey Improvement Project to further enhance the industrial survey, including by using an internet-based survey.[130]

82. The industrial customers have generally shown the ability to forecast their demand with a good degree of accuracy, the notable exception being weather-sensitive customers. As a result, there have been only modest variances in the forecast in the past years.[131] Other methods of forecasting industrial demand (e.g. GDP) would be less accurate.[132]

83. As the FEU's industrial forecast is based on the reasonable, proven methodology the forecast for the test period should be accepted.

B. CONCLUSION

84. The FEU's forecast of demand and revenues for FEI, FEVI, FEW and Fort Nelson is reasonable, based on sound methods and supported by the evidence in the proceeding. Accordingly, the FEU submit that the forecast should be accepted.

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[129] Exhibit B-1, p. 89.

[130] Exhibit B-1, p. 80. Exhibit B-9, BCUC IR 1.29.2.

[131] Bennett: T5, p. 857, ll. 15 to 22; Stout: T5, p. 860, ll. 10 to 17.

[132] Exhibit B-1, p. 84-85; Exhibit B-9, BCUC IR 1.27.1 and 1.32.1; Exhibit B-6, BCOAPO IR 1.17.1.

PART FOUR: COST OF SERVICE: CORE MARKET ADMINISTRATION EXPENSE AND FEVI'S COST OF GAS

85. The FEU are seeking approval of the consolidated Core Market Administration Expense (CMAE), and allocation percentages, for FEI, FEW, and FEVI as set out in Section 5.2 of the Application. Only FEVI, which still has bundled rates, is seeking approval of its 2012 and 2013 cost of gas in this Application. Gas costs for FEI, FEW and Fort Nelson are approved in separate applications to the Commission and are subject to quarterly review and re-setting. The FEU submit that the proposed CMAE and the forecast cost of gas is reasonable and reflects costs necessary for the provision of service for customers.

A. CORE MARKET ADMINISTRATION EXPENSE (CMAE) COSTS

86. The FEU's CMAE are the gas supply management costs. CMAE activities have been provided on the basis of a single administrative function since 2004 and are allocated between the gas supply portfolios based on customer count. For 2012 and 2013, 90 percent of CMAE forecast will be allocated to the Mainland, including Whistler, and 10 percent to FEVI.[133] CMAE costs are treated as a flow-through cost to core market customers as part of gas costs, so any savings realized over the test period will flow to customers.[134]

87. Compared to 2010 and 2011 approved amounts, expenditures are forecast to increase by $277 thousand in 2012 and by an additional $145 thousand in 2013.[135] The increase in expenditures forecast for 2012 is caused by (a) labour and materials inflation, (b) the need for an additional employee required to assist in the completion of an increased level of Gas Supply activities, and (c) the need to support several enhancements to the information systems used by Gas Supply.[136] The need for the new employee was discussed in detailed in response to BCUC IR 1.41.1 and 1.41.2. (Exhibit B-9). The service enhancements driving 2012 costs were described in response to BCUC IR 1.41.3 (Exhibit B-9) and relate to systems used to complete gas cost forecasts, and to how counterparty credit information is obtained,

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133 Exhibit B-1, p. 142.

134 Exhibit B-1, p. 142.

135 A detailed breakdown of the CMAE expense from 2010 to 2013 is provided in Exhibit B-9, BCUC IR 1.40.1.

136 Exhibit B-1, p. 142-143.

distributed to FEI's midstream group, and managed. The increase in expenditures forecast for 2013 is caused by labour and materials inflation.[137]

88. The FEU submit that the forecast cost increases for CMAE are reasonable in light of the need identified in the evidence.

B. FEVI'S FORECAST COST OF GAS

89. In Undertaking No. 24.[138] FEVI's financial schedules were updated to reflect the commodity costs and supplemental put that were included in the third quarter gas cost report, resulting in a forecast cost of gas of $74,540 thousand and $77,435 thousand for 2012 and 2013, respectively.[139] Variances between the actual incurred cost of gas and the approved forecast cost of gas for the test period will be captured in FEVI's GCVA for amortization in future rates.[140]

90. The Gas Supply department (which is within the Energy Supply and Resource Planning department) is tasked with managing gas costs to ensure a reliable, cost-effective supply.[141] It develops and implements Annual Contracting Plans and Price Risk Management Plans which are filed with the Commission. The Annual Contracting Plan outlines the portfolio requirements to meet the needs of core customers under design day conditions. The Price Risk Management Plans are designed to reduce market price volatility and what would otherwise result in rate volatility for customers.[142]

91. FEVI's cost of gas includes unaccounted for gas ("UAF"), company use gas, carbon tax and gas control service. The FEU have produced reasonable forecasts for these costs

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[137] Exhibit B-1, p. 143.

[138] Exhibit B-52.

[139] See Evidence of Ms. Des Brisay and Ms. Roy for an explanation of the changes, T4, p. 625, l. 4 to p. 628, l. 6.

[140] Exhibit B-1, P. 140. Approved by Commission Order No. G-2-03, the Vancouver Island GCVA was established effective January 1, 2003 to accumulate the variances between the actual and the forecast gas costs on a royalty adjusted basis, for amortization and recovery from, or refund to, sales customers in future rates.

[141] Exhibit B-1, section 5.2.

[142] Exhibit B-1, p. 138

as presented in section 5.2 of the Application. Historical UAF by service area is shown in Exhibit B-9, BCUC IR 1.39.1.

92. There were few questions related to these forecast costs during the proceeding and no issues were raised. The FEU submit that they should be accepted for ratemaking purposes as filed.

PART FIVE: COST OF SERVICE: OPERATIONS AND MAINTENANCE (O&M) EXPENSE

93. The FEU have provided extensive evidence to support the forecast O&M for 2012 and 2013. In this Part, the FEU address:

- Labour and inflation as it applies across all departments;
- O&M by department;
- Overheads Capitalized; and
- Corporate and Shared-Services.

A. LABOUR AND BENEFIT INFLATION COST DRIVER

94. Labour and benefit inflation are primarily non-discretionary costs required to fund expected wage and benefit increases. As the labour and inflation cost-driver is the same across all departments, it was considered separately in section 5.3.2.2 of the Application. The forecast labour and benefit inflation cost reflects the appropriate management of labour costs to ensure the FEU are able to attract and retain talented people for key positions, while guarding against paying above market rates for other positions.

95. The FEU approach to compensation and benefits includes a total compensation package that rewards employees with competitive base salaries and wages, incentive compensation, benefits, and paid time-off. The key objectives of the compensation and benefits program and the application of the program to executives, M&E and unionized employees are discussed in the Application.[143] The focus in the proceeding was the FEU's policy regarding executive compensation and the impact of the Balanced Scorecard.

96. Compensation for all FEU executive positions is targeted at the market median.[144] Compensation levels are evaluated against information provided by the Hay Group

[143] Exhibit B-1, pp. 36 to 38. The FEU's forecast of labour and inflation costs was submitted confidentially so as not to compromise the FEU's negotiations with its unionized labour bargaining units.

[144] Exhibit B-12, BCOAPO IR 2.7.2.

regarding the 50th percentile salary points (midpoints) and short-term incentive targets for similarly rated positions from a broad comparator group. The comparator group reflects the type of companies with which the FEU typically compete for talent, including a broad range of industrial commercial entities from across Canada; the FEU's current executives have come from a variety of industries, including: financial consulting, properties, energy and utilities.[145] Individual salary placements are generally to be within a range of 80% to 110% of the market rate for the position as established using the Hay evaluation methodology. Individual salary placement within the range is established giving due consideration to job performance and work experience.[146] The FEU submit that an approach of targeting the market median based on objective information is appropriate and is in the long-term best interests of customers.

97. The thrust of some of the questions from Commission Staff and Commission counsel was that the ultimate beneficiary of the Balanced Scorecard and incentive compensation is the shareholder, and not customers. Compensating employees, however, is a fundamental cost of providing service. The incentives paid under the Balanced Scorecard are a performance tool that is part of an overall compensation package, and serve customers well. As Mr. Thomson stated:

> … I don't think that you can -- or you should -- ought not to pick apart a performance tool on its individual components, and start to allocate those. I think that a reward system for employees is part of an overall compensation package.
>
> And so, having employees who are productive and doing a good job for the company ensures good customer service.[147]

98. Ms. Drope explained that the point of the bonus program is to focus on the business priorities in any given year. The Scorecard, she noted, is designed to balance the interests of customers, shareholder and employees. It is ultimately to the benefit of the customer to have productive employees who are providing good service (Employee category

[145] Exhibit B-6, BCOAPO IR 1.9.2; Exhibit B-12, BCOAPO IR 1.17.1 and 1.17.3.

[146] Exhibit B-12, BCOAPO IR 2.7.2.

[147] Thomson: T4, p. 498, ll. 11-20.

and customer satisfaction), who are cognizant of the importance of prudent O&M and capital spending (Customer category). While the Scorecard includes a criterion of achieving the net earnings target based on the approved rate of return, the FEU are seeking to earn what the Commission has approved as being just and reasonable and adequate for the FEU to attract capital on reasonable terms and maintain its debt ratings, which is to the benefit of customers.[148] In any event, Ms. Drope stressed that "The elements should not be considered individually. They're not mutually exclusive. They interrelate."[149] It is the whole package which together is designed to meet the objectives of the compensation approach.

99. The FEU submit that its labour and benefit inflation increase is reasonable and the use of the Balanced Scorecard as a compensation management tool remains appropriate.

B. OPERATIONS DEPARTMENT (DISTRIBUTION & TRANSMISSION)

100. The FEU's Operations Department encompasses the Distribution and Transmission groups and is the largest department in terms of number of employees, budget and geographical footprint.[150] The Application provides a detailed account of the department's structure, 2010 actuals, 2011 projection and 2012-2013 forecast O&M for each utility.[151] Aside from labour and inflation, Distribution is forecasting cost increases due to the following cost drivers: codes and regulations, demographics, and service standards and reliability. Transmission is forecasting savings in the codes and regulations cost driver and cost increases due customer and stakeholder expectations, demographics, and service standards and reliability. The reason for the cost increases for each of these cost drivers is described in the Application for each utility for 2012 and 2013[152] and the broader discussion will not be repeated here. The following sections will focus on particular topics explored in information

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[148] See Decision, *In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Return on Equity Capital Structure*, December 16, 2009 (BCUC Order No. G-158-09), at p. 15. See Appendix B: Book of Authorities, Tab 1.

[149] Drope: T7, p. 1131, ll. 3 to 5.

[150] Exhibit B-1, p. 160.

[151] Exhibit B-1, pp. 160 to 185.

[152] Exhibit B-1, pp. 160 to 185.

requests or cross-examination. The FEU submit that the evidence supports the forecast O&M for the Operations department.

(a) Right-of-Way Signage

101. The FEU addressed a number of questions about the $120 thousand requested by FEI in 2012 and 2013 to change Intermediate Pressure and Transmission Pressure pipeline markers from orange to yellow. The interest in this program appears to have been based in large measure upon a suspicion that the line-marker program has been undertaken at this time only to replace serviceable markers with ones that bear the new FortisBC name. In fact, this is a public safety and code compliance issue. The FEU submits that this expenditure is non-discretionary and should be approved.

102. ANSI standard Z535.1 requires that Intermediate Pressure and Transmission Pressure pipeline markers must be yellow. FEVI's markers are already compliant with Z535.1 and the distribution pressure line markers have already been converted to yellow.[153] FEI's adoption of the stipulated signage for the transmission system is still essential for full compliance. Uniformity in the pipeline markers based on the widely recognized colour scheme ultimately ensures that customers, the public and first responders are given all possible opportunity to recognize the presence of a natural gas pipeline and its inherent risks.[154]

103. The program to bring the pipeline markers into compliance with the requirements of ANSI Z535.1 starts in 2012 and extends for approximately five years at a cost of $120 thousand per year.[155] The 2012-2013 estimates are based on the number of kilometres of pipeline, an estimated number of markers per kilometre, and an estimated cost per marker.[156] In order to ensure all markers are changed, the replacements will be performed as a focused

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[153] Exhibit B-9, BCUC IR 1.50.1.

[154] Exhibit B-17, BCUC IR 2.17.4.

[155] Exhibit B-9, BCUC IR 1.50.1

[156] Exhibit B-9, BCUC IR 1.50.1. 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.

effort, but also in coordination with routine activities.[157] Although ANSI Z535.1 does not require compliance within a specific time period, it is important to be compliant within a timely manner.[158] It is not feasible to replace all of the markers through routine activities in a timely manner.[159]

104. While the new line markers will include the FortisBC name, it is not required.[160] Previously converted distribution markers still bear the Terasen name, and they will continue to have the Terasen name until they are replaced in the course of its normal maintenance program.[161] This evidence reinforces that the initiative is being driven by code compliance and public safety.

(b) Distribution - Asset Compliance Managers

105. The proposed increase of $250 thousand in 2013 for three Asset Compliance Managers, an expense which was probed in information requests and at the hearing, is another codes and regulations requirement. These Asset Compliance Managers are to be tasked with ensuring that assets continue to be installed and maintained to safe and reliable standards.[162] Their role is required to meet code requirements. Ultimately, their work will protect customers, the public, employees and the utility plant.

106. Asset compliance management is a requirement under the Integrity Management Plan, which has evolved to meet CSA Z662 code and safety and reliability objectives. CSA Z662 requires that the Companies identify and document the personnel responsible for integrity management activities, including audits.[163] The audits are targeted at ensuring the ongoing integrity of the assets.

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[157] Exhibit B-17, BCUC IR 2.17.2.
[158] Exhibit B-9, BCUC IR 1.50.3; Exhibit B-17, BCUC IR 2.17.3.
[159] Exhibit B-17, BCUC IR 2.17.1.
[160] Exhibit B-9, BCUC IR 1.50.4.
[161] Bell: T7, p. 1092, ll. 15 to 23.
[162] Exhibit B-1, p. 172.
[163] Exhibit B-9, BCUC IR 1.51.3; Exhibit B-17, BCUC IR 2.18.1.

107. Current Company policy requires local managers to complete a specified number of audits per month,[164] but Mr. Bell explained that the local managers are unable to audit all of the areas required.[165] The Asset Compliance Managers will assume the responsibility for asset integrity audits and will have the power to stop work and require corrective measures.[166] Three additional Asset Compliance Managers permit one manager per operational zone and facilitate effective monitoring of field work activities. It is neither feasible nor practical to have fewer Asset Compliance Managers cover the entire the natural gas distribution service areas and the full scope of activities including new installations, routine operations and maintenance, emergencies, customer service work, design, and planning.[167] The evidence supports the FEU's determination that the resources requested are the minimum numbers required to meet the FEU's responsibilities as identified by CSA Z662.[168]

(c) Locks and Security Devices

108. FEU must standardize locks and security devices at field facilities to maintain adequate security measures and meet requirements of CSA Z662 and the new CSA Z246.1.[169] The FEU plan to complete 50 percent of the lock upgrade and replacements in 2013 at a cost of $350,000 for FEI and $40,000 for FEVI.[170] The remainder of the work will be completed in 2014.[171]

109. The timing and requirements of CSA Z662-07 and CSA Z246.1 are as follows:

- Adopted in November 2007, CSA Z662-07 assigns responsibility for appropriate security measures to the operator. For example, CSA Z662-07, Clause 10.5.5

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164 Exhibit B-9, BCUC IR 1.51.3.

165 Bell: T7, p. 1079, ll. 18 to 26.

166 Exhibit B-17, BCUC IR 2.18.1. Bell: T7, p. 1080, ll. 1 to 8.

167 Exhibit B-1, p. 172; Exhibit B-9, BCUC IR 1.51.2.

168 Exhibit B-17, BCUC IR 2.18.1.

169 Exhibit B-1, p. 172.

170 Exhibit B-1, p. 172 and 177.

171 Exhibit B-1, p. 172.

states the following: "Conditions that can adversely affect the security of the pipeline system shall be corrected".[172]

- By Information Letter #OGC 09-27, dated September 24, 2009, the Oil and Gas Commission advised of their intent to adopt CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems. No deadline for formal adoption was noted; however, comments were invited until December 31, 2009. FEU understands that the Oil and Gas Commission is on track to adopt CSA Z246.1 in 2012.[173] CSA Z246.1, Clause 9.3.8 states: "High-quality locks should be used to deter access to important equipment, facilities, or areas. If using locks, the operator shall establish and document a key control procedure. The key control procedure shall provide an issuance and return tracking system to prevent unauthorized use or loss of keys and locks."[174]

110. All FEU field facilities are secured and to date there have been no incidents impacting the security of the natural gas delivery system as a result of unauthorized use of keys.[175] However, changes are required to provide a higher level of security protection, specifically with respect to the ongoing control of keys and access.[176] Security vulnerability assessments of gas delivery facilities have identified key control as an area where improvement is required.[177] Natural gas facilities have also been identified as likely targets for domestic and international terrorists.[178]

111. The program is also 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

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172 Exhibit B-17, BCUC IR 2.19.1.
173 Exhibit B-17, BCUC IR 2.19.1.
174 Exhibit B-17, BCUC IR 2.19.1.
175 Exhibit B-9, BCUC IR 1.52.1; Exhibit B-17, BCUC IR 2.19.2.
176 Exhibit B-9, BCUC IR 1.52.1.
177 Exhibit B-9, BCUC IR 1.52.2.
178 Exhibit B-9, BCUC IR 1.52.1.

personnel and provide access to facilities as the work requires.[179] Recent gas emergency events and exercises have also raised awareness of the issues associated with moving personnel from one area of the Province to another in support of local activities.[180] Different keys are also used between Distribution and Transmission facilities, limiting the ability to move personnel between the work groups.[181]

112. The FEU submit that the costs for the lock and security device program are reasonable and should be accepted in the best interests of customers.

(d) Distribution – Additional Planners and OSRs

113. Within Distribution, under the Service Standards and Reliability Cost Driver, the Operations Centre will require six additional positions in 2012 and three additional positions in 2013 to address the increase in workload. In 2012, three Planners and three Operational Support Representatives ("OSRs") in the Closing and System Survey sub-group of the Distribution group are required.[182] In 2013, three additional Planners, including a work-leader to supervise a large planning group, are required.

114. 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 and 1 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.[183]

The Role of the New FTE's

115. The Planners typically work on Capital activities requiring significant interaction and coordination with customers, developers and municipalities including complex services,

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[179] Exhibit B-1, p. 172.

[180] Exhibit B-9, BCUC IR 1.52.2.

[181] Exhibit B-9, BCUC IR 1.52.1 and 1.52.2; Bell: T7: p.1193, ll. 16-24.

[182] Exhibit B-1, pp. 173 to 174.

[183] Exhibit B-9, BCUC IR 1.53.1.

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.[184] Mr. Bell explained that the role of the planners was different than asset management:[185]

> The planning group provides that in-field -- those additional resources are that in-field planning part of our organization. So if asset management says we will go out and we will replace this piece of asset in this neighbourhood, for instance unprotected pipe, the planners are the ones that will go out into the field and build the construction drawings for the contractor or the employees to go out and do that work. So they are a support of construction group rather than, I would say, support of asset management.
>
> …
>
> So asset management is in charge of the -- is in charge of the physical asset, ensuring that there's a plan in place for the longevity. The planners are the ones that they go out and they have a look at a road and say there's trees on the road that we're going to have to deal with, there's this much grass, there's this much concrete that's got to be cut. So they put together the dollar values for the construction project itself, as well as do the routing for that. So that's the plan that they work to.

The Planners typically meet on construction sites with homeowners, developers and municipalities to design and cost estimate gas system infrastructure (capital activities). They also engage in training, supervision and reviews of municipal project plans (O&M activities).[186]

116. OSRs are clerical staff who set appointments (capital and O&M).

117. The request for additional headcount is primarily being driven by an increase in capital work relating to municipal and government projects which require relocation of gas mains and services, hazards mitigation work such as inactive services and stub services which

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[184] Exhibit B-9, BCUC IR 1.53.1.

[185] Bell: T7, p. 1082, ll. 2 to 12 and p. 1083, ll. 2 to 11.

[186] Exhibit B-1, p. 174.

need to be cut-off at the main, and meter-set upgrades.[187] Mr. Bell expanded on this and identified two main reasons for the increase in workload on such projects:

- The first reason relates to a shift away from the geo-code pricing model. As noted in the quote above from Mr. Bell, the FEU were able to decrease the need for planners by moving to the geo-code pricing model for extensions in which average costs are used instead of sending planners out to the site. However, experience has shown that the geo-code pricing model is not appropriate for large or complex extensions as it has led to some large variances from forecast.[188] (This is discussed in the context of the MX Test in Part Ten.) Thus, planners needed to be added in order to move away from the geo-code pricing model.[189]

- The second reason is that municipal permitting requirements are requiring planners to become more involved in extension projects.[190]

Trend of Planners vs. Capital Work

118. During cross examination, Commission staff produced a Witness Aid to show the increase in planners and OSRs and compared to the amount of capital work. The FEU prepared a different graph which Mr. Bell indicated presented a more accurate view.[191] This was informed by a number of factors that were not accounted for in Staff's Witness Aid, including:

- The OSRs are clerical staff who set appointments, so it is not appropriate to include OSRs in comparing staff numbers to the amount of capital work.[192]

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[187] Exhibit B-9, BCUC IR 1.53.3.
[188] Exhibit B-9, BCUC IR 1.99.2.
[189] Bell: T7, p. 1173, ll. 11 to 16.
[190] Bell: T7, p. 1178, ll. 1 to 16.
[191] Exhibit B-50.
[192] Bell: T7, p. 1172, l. 1 to p. 1173, l. 10.

- The Staff Witness Aid included all services-related capital work, but the capital work that the Planners are involved in is only the more complicated extensions, and not meters for instance.[193]

119. Mr. Bell cautioned that his graph still did not capture all the necessary information and should therefore be used as a rough indication only:[194]

> But what's not included in this -- in the graph that I tried to produce is CPCNs, for instance. So in 2010 you see a drop here in the projects, but we had planners in Whistler doing the CPCN.
>
> …
>
> So as I was saying before, even when I tried to put together this graph here, I struggled a bit with it because out in the 2007, we would be doing about -- I think it was around $400,000 in service line abandonments. In 2010 and '11 I think we're up to about $3 million worth. Those aren't included in that red line. In addition, we're doing another $2 million this year in hazard repairs, and that isn't included in the 28.4 number.
>
> So to really -- there's a lot of other work that these planners do, and we did leave the service line numbers in here, but again, they don't get involved in all of the service line planning because that's not the model that we designed when we reduced the field staff starting back in 1998. We went to a centralized costing model with geo-pricing, and we weren't going to send planners out unless it was absolutely necessary.

120. The FEU's graph still shows that the number of planners is increasing; however, as described above, the increase in Operations Centre personnel is not directly linked to customer additions growth.[195]

121. In the FEU's submission, the need for the additional FTE's in the Operations Centre has been demonstrated and should be accepted for the purposes of calculating rates.

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[193] Bell: T7, p. 1172, l. 1 to p. 1173, l. 10.

[194] Bell: T7, p. 1173, ll. 11 to 20 and p. 1175, l. 1 to 1176, l. 20.

[195] Exhibit B-9, BCUC IR 1.53.3.

(e) NGV

122. The original forecast transmission and distribution O&M costs to operate and maintain CNG and/or LNG stations[196] were revised downwards by $110 thousand in 2012 and $225 thousand in 2013 following the Commission's CNG-LNG Decision (Order No. G-128-11) and NGV Incentives Decision (Order No. G-145-11).[197] The initial NGV fueling station incremental customer additions forecast (three stations in 2012 and four stations in 2013) had been premised on the availability of NGV incentives.[198] Taking into account the revision noted above, FEI Distribution requires $115 thousand in 2012 and no incremental costs in 2013 to operate and maintain NGV assets. In 2011, these costs were captured in the 2011 CNG and LNG Service Costs and Recoveries deferral account. Regular operation and maintenance of NGV assets, specifically CNG and/or LNG stations, are required to ensure public safety and reliability.[199]

123. FEI Transmission will also incur increased O&M costs $133 thousand in 2012 and an additional $106 thousand in 2013 for increased liquefaction to replenish LNG tank levels at the Tilbury LNG Facility.[200] These incremental costs are offset by incremental revenue earned under Rate Schedule 16.[201] As discussed in the CNG and LNG Fueling Report, the "take or pay" contract rates negotiated with NGV customers are set to recover the cost of investing in and maintaining CNG and LNG facilities.[202]

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[196] The original Distribution and Transmission O&M forecast related to NGV service was described in the Operations section of the Application (section 5.3.5) and discussed in more detail in Appendix I to the Application: Compressed Natural Gas and Liquefied Natural Gas Fueling Report.

[197] Exhibit B-23.

[198] Exhibit B-21, p. 3.

[199] Exhibit B-1-3, Revised Application p. 175.

[200] Exhibit B-1, p. 183 and Appendix I, p. 9. These costs are for increased electricity costs at the Tilbury LNG Facility.

[201] Exhibit B-1, p. 183.

[202] Exhibit B-1, Appendix I, p. 7.

(f) Biomethane

124. FEI requires $23 thousand in 2012 and an incremental $68 thousand in 2013 to operate and maintain the Biomethane assets.[203] Regular operation and maintenance of Biomethane assets, similar to pressure regulating stations, is required.[204] Pursuant to BCUC Order No. G-194-10, O&M costs required to operate and maintain interconnection facilities are recovered from all customers through delivery rates.[205]

125. The O&M costs incurred to date are well within the approved budgeted values for 2011 identified in the original Biomethane Application.[206] The costs for 2012 and 2013 are adjusted by an inflation factor of 2% from the original approved spending amount in 2011.[207] The Distribution and Transmission costs are for the Interconnect Facilities for Catalyst and Columbia Shuswap Regional District ("CSRD") and future projects under consideration.[208] A detailed account of all Biomethane O&M Costs has been provided in attachment 188.1 to Exhibit B-9-1.

126. The FEU submit that it is most appropriate to recover these Biomethane program costs in the forecast period to match the time in which they are incurred. Biomethane is a component of the FEU's natural gas business and operations and should be treated consistent with other forecast costs that apply to all customers.[209]

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[203] Exhibit B-1, Appendix J, p. 7; Exhibit B-9, BCUC IR 1.179.2. In the Biomethane Report, FEI has provided the total O&M costs broken out by Biomethane customers and all customers for 2012 and 2013. The $23 thousand in 2012 and an incremental $68 thousand in 2013 are included in the Interconnect Facilities – Materials and Supplies column in Table J-2.

[204] Exhibit B-1, p. 175.

[205] Exhibit B-9, BCUC IR 1.179.1.

[206] Exhibit B-1, Appendix J, p. 7.

[207] Exhibit B-1, Appendix J, p. 7.

[208] Exhibit B-9, BCUC IR 1.183.4.

[209] Exhibit B-9, BCUC IR 1.187.1.

(g) Costs Driven by Activity / Unit Cost Changes

127. Distribution is forecasting a number of cost pressures due to the Service Standards and Reliability cost driver. In the field service delivery area, the need for some additional funds is driven by changes in activity levels and inflation in unit costs. As discussed in Part Two above, the Operations Department employs a zero-based budgeting approach for the activity-based aspects of its budget.[210] Activities reflected in FEI's budget are explained below.[211]

- **Battery upgrades for industrial meters** ($160 thousand):[212] This is a new, one-time, two-year program to replace industrial alkaline batteries with lithium battery packs, involving a significant non-labour component (materials, contractors).[213] Replacing alkaline batteries with a lithium battery pack will result in the need for only two scheduled visits to the meter, instead of three as currently required. The replacement program is expected to be completed over three years and gradually result in a reduction in unscheduled industrial meter exchanges which are costly and inconvenient. FEI currently has approximately 500 of these unscheduled industrial meter visits annually and has reduced this quantity to 450 and 400 in 2012 and 2013 respectively to reflect the start of this program. The most significant reduction in unscheduled visits will come in 2015 at the end of the three-year program.[214]

- **Bridge crossing repairs** ($110 thousand):[215] For FEI, there is a small incremental amount in 2013 compared to 2012 which represents inflation.[216] For FEVI, the

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[210] See Exhibit B-17, response to BCUC IR 2.21.1.

[211] Exhibit B-1, p. 175. In support of these funding requests, the FEU have provided detailed working spreadsheets showing historical detailed information on the Field Service Delivery Activities levels. Exhibit B-9, BCUC IR 1.54.1, Attachment 54.1; Exhibit B-17, BCUC IR 2.21.1., Attachments 22.1a and b; Exhibit B-59, Undertaking No. 31.

[212] Exhibit B-1, p. 175.

[213] Exhibit B-9, BCUC IR 1.54.1.

[214] Exhibit B-17, BCUC IR 2.21.2.

[215] Exhibit B-1, p. 175.

significant item for 2013 is bridge crossing repairs for the Bay Street bridge in Victoria which is estimated at $330 thousand. The work includes repairing and recoating the two pipes (distribution pressure and intermediate pressure) which are supported by the bridge.[217]

- **Station transition repairs** ($100 thousand):[218] This is a new program involving a significant non-labour component (materials, contractors).[219] Station piping is prone to heavy corrosion where the pipe transitions from below to above ground and, without maintenance, repair and recoating, is a significant risk to pipeline integrity. This program is to review and repair approximately 20 stations per year over and above any station transition issues resolved through upgrade, replacement or retirement of the station. Incremental funding is required to assess existing stations where corrosion of this type has been reported and to complete repairs as required.[220]

- **Leak repairs** ($110 thousand):[221] The additional funding required in 2012-2013 reflects the higher costs experienced in leak repairs in 2009 and 2010. The higher leak repair costs in 2009 and 2010 are due in part to a higher proportion of main leak repairs, which require considerably more effort and expense to repair, while the number of service leaks has decreased.[222] Costs are also increased by the addition of Distribution Apprentices, in order to properly respond to the demographic challenges.[223] There is no increase in leak repair activities forecast for 2013 from 2012 requested levels. The $38,000 incremental

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[216] Exhibit B-9, BCUC IR 1.54.1.

[217] Exhibit B-1, p. 177.

[218] Exhibit B-1, p. 175.

[219] Exhibit B-9, BCUC IR 1.54.1.

[220] Exhibit B-17, BCUC IR 2.21.2.

[221] Exhibit B-1, p. 175.

[222] Unit costs have a high degree of variability between $1,000 and $200,000 depending on the complexity of the leak and the repair. Exhibit B-9, BCUC IR 1.54.1.

[223] Exhibit B-17, BCUC IR 2.20.1.

amount is for 3 percent wage/vehicle/contractor inflation on the 2012 base funding ($1,258,000) for leak repairs. [224]

- **Line locates** ($125 thousand):[225] 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. [226] The higher recent unit cost experience per locate is primarily due to the presence of larger infrastructure projects in the mix. Several of these projects are related to the federal economic action plan to sprinkle projects throughout the Province in an effort to stimulate the economic recovery. Locate completion times include travel time and range from one hour to one week per location. The longer duration locates usually involve major construction infrastructure projects (interchanges, arterial roadways, etc.) where work is being done in close proximity to the FEU's gas lines.[227]

- **Valve inspections** ($200 thousand):[228] The valve inspection budget is primarily determined by the number and type of valves being inspected and the average unit cost required to complete the inspections. The 2012 and 2013 forecast is based on the number of scheduled valves to be inspected (including main, service and TP valve types) multiplied by the forecast 2012 and 2013 unit costs which in turn are based on the 2010 actual experience, adjusted to reflect 2012 and 2013 labour/vehicle charge-out rates including inflationary increases.[229] The 2013 increment to the 2012 request is primarily labour/vehicle inflation.[230]

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[224] Exhibit B-17, BCUC IR 2.21.6. The incremental amount of $38,000 is included in the inflation cost driver (refer Table 5.3-17 p. 171 in the Application).

[225] Exhibit B-1, p. 175.

[226] Exhibit B-9, BCUC IR 1.54.1.

[227] Exhibit B-17, BCUC IR 2.21.10.

[228] Exhibit B-1, p. 175.

[229] Exhibit B-17, BCUC IR 2.21.8.

[230] Exhibit B-9, BCUC IR 1.54.1.

- **Gas odour calls** ($200 thousand):[231] The gas odour call budget is established each year based on the forecast number of calls multiplied by the forecast average unit cost. The average unit cost, based on previous year's actual experience, is driven by labour/vehicle charge-out rates which are mostly inflationary changes (including benefits). The 2010 actual volume of activity (21,058) and average unit costs ($99) were used as the basis to forecast the 2012 and 2013 requirement. The 2010 volumes and unit costs were very similar to the 2009 volumes and unit costs, although actual costs related to gas odour calls have been increasing since 2007.[232] The increase of $63,000 in gas odour expense in 2013 is related entirely to the change in forecast unit cost from $99 to $102 per call. The change in unit cost is driven by the year-over-year change in the labour/vehicle charge-out rate which is primarily wage related inflation of approximately 3 percent.[233]

- **Meter to cash (lock-offs, etc.)** ($1.13 million). This expense is offset by meter to cash recoveries ($1.12 million) through an increase in the reconnection/reactivation fee.[234] The reconnection/reactivation fee is dealt with separately below.

128. FEVI requires an additional $353 thousand in 2012 to support various field service delivery activities, including those above.[235]

129. The FEU submit that the forecast costs are reasonable based on the extensive supporting evidence discussed above and should be accepted as filed.

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[231] Exhibit B-1, p. 175.

[232] Exhibit B-17, BCUC IR 2.21.11.

[233] Exhibit B-17, BCUC IR 2.21.12.

[234] Exhibit B-1, p. 175 and Appendix F-1.

[235] Exhibit B-1, p. 177.

(h) Reconnection/Reactivation fee

130. Appendix F-1 sets out the FEU's plan to increase the reconnection/reactivation fee to $100 (regular hours) and $140 (after hours) to offset the increased costs related to these activities. The planned fee is the implementation of existing tariff terms and conditions as set out below.

131. Section 5.4 of the Tariff for FEI, FEVI and FEW states that reactivation charges must at least pay the costs incurred in de-activating and re-activating the service. As shown in Appendix F-1, however, the actual and forecast disconnection and reconnection/reactivation costs are higher than the current charges of $65 (regular hours) and $105 (after hours).[236] The analysis of costs used to design the fee in Appendix F-1 shows that the FEU weighted average forecast cost for performing a lock-off service and an unlock and relight[237] service during regular hours is $100 and during after-hours is $125. The reasons for the difference between the proposed $140 charge for after hour reconnects and the FEU weighted average forecast cost of $125 are: (1) to enable the recovery of costs for instances where only a lock-off is performed (i.e. when there is no corresponding reconnect); and (2) to encourage customers to request reconnects during regular hours, when it is more cost-effective and operationally more efficient to do the reconnect. The rationale for this was explained in further detail in the response to Undertaking No. 31. Table F-5 in Appendix F-1 shows how the proposed reconnect fees are designed so that when multiplied by the number of reconnect activities (regular and after hours) they recover the total cost of $3,392,620 for lock-offs, relights and administration expense as calculated in Table F-4.[238]

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[236] Historical lockoff and reconnection costs have been provided in Exhibit B-17, BCUC IR 2.21.1 and in a revised form in Undertaking No. 31, Exhibit B-59.

[237] The FEU do not have a lock-off fee as the FEU are generally unable to collect the lock-off costs at the time of a lock-off. Instead, the current and proposed Reconnect/Reactivation fee is designed to recover the total costs of all lock-offs and reconnects. Exhibit B-59, Undertaking No.31.

[238] Exhibit B-62, Undertaking No. 34. From an operational aspect, a gap in the regular and after-hours fee encourages customers to request a relight during regular hours when more field resources are available. As after-hours resource coverage is limited, especially in small towns, it is challenging to schedule and dispatch field resources to an after-hours relight request while appropriately maintaining emergency response service levels.

132. Lock off and reconnect activity counts for 2012 and 2013 were forecast based on activity levels from 2010. Higher than average disconnects in the preceding years due to high gas costs, economic conditions, and the recession make the 2010 disconnect and reconnect activity levels the most indicative forecast for 2012 and 2013.[239] Although the level of activities does have an impact on the overall budget required to perform these services, the fee established and the number of times it is collected provide an offsetting recovery so that this activity is neutral for customers generally.[240]

(i) Operations O&M Related to LTSP

133. The need to undertake Long-Term System Planning (the LTSP) is driving O&M increases in the Operations department in both the Distribution and Transmission areas. The O&M to support the LTSP is for two broad purposes. The first 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. The second purpose is to support the development and completion of capital projects. Under current accounting guidelines these costs, which historically have been treated as capital, now need to be treated as an O&M expense.[241]

134. To support the LTSP, Distribution requires $1 million in 2012 and $500 thousand in 2013.[242] This is offset by O&M reductions resulting from the elimination of similar studies that were completed in 2011 (seismic risk analysis for $145 thousand and single point of failure analysis for $200 thousand).[243]

135. In addition, detailed system sustainment assessments that look beyond five years are required in order to proactively develop a LTSP, and are driving the increase in the

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[239] Exhibit B-59, Undertaking No. 31, p. 1-2.

[240] Exhibit B-59, Undertaking No. 31, p. 1-2.

[241] Exhibit B-9, BCUC IR 1.57.1.

[242] This includes the $500 thousand in consultant costs referenced in Exhibit B-17, BCUC IR 2.16.1. Bell at T7, p. 1164, l. 12 to p. 1165, l. 8.

[243] Exhibit B-1, p. 176.

number of FTE's for Asset Management and Planning.[244] The specific Distribution resources required are as follows:

- Asset Management will require one additional 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.[245]

- The Operations Centre will require additional planners in 2012 ($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. These resources are required to continue to plan, design and coordinate asset renewal projects and ensure capital investments are appropriately coordinated.[246]

136. As explained by Mr. Bell:[247]

> … these additional funds are to put together the more in-depth asset health review, to bring some tools within the organization so that we can include other factors than just leaks and an engineering assessment to make those longer-term decisions. So this isn't -- this is all about, one, developing a long-term plan, putting the people, the tools and the resources in place to have a look at that plan, and build a proper replacement plan out of that. And it's that longer-term replacement plan that we want to develop here.

137. Transmission requires additional resources of $1.1 million in 2012 and an additional $803 thousand in 2013 to facilitate the FEU's LTSP activities. These required

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[244] Exhibit B-9, BCUC IR 1.55.1.

[245] Exhibit B-1, p. 176; Exhibit B-9, BCUC 1.55.2

[246] Exhibit B-1, p. 176.

[247] Bell: T7, p. 1076, l.18 to p. 1077, l.2.

additional system sustainment resources include four transmission management and field staff employees for the increased asset management activities that the FEU expects as it completes detailed assessments of aging assets to determine the scope and timing of future asset renewals. Additional consulting resources are also needed to help with the further refinement of asset management processes and for the completion of project feasibility investigations. These additional O&M costs need to be incurred to plan for increased asset renewals, to complete feasibility studies and early stage planning, and to prepare budget requests for a variety of potential projects required to provide a long term view of asset management and system sustainability.[248]

138. Mr. Bell described the role of these new employees as follows:[249]

> … these are transmission employees. So, the support that they would provide to asset management would be the asset manager will have them go out and have a look at an asset. And say, you know, "Tear apart the asset, have a look at what's the condition of it." They will send a detailed report back to say, in fact, this asset is in good shape, or the bundle inside this line heater is showing signs of corrosion and needs to be replaced.
>
> So, that -- you know, the other thing that asset management, when we do the more detailed asset health review, gets from these employees, is that employee in the field's feedback. And so they will go to the employee and they will say, "You were working on this transmission line, you know, in addition to these notes, what else have you seen there?" And the employee will provide them anecdotal stuff. For instance, "Well, I've been around for 15 years and every year I go back to that location and I have been seeing this and this and this. I've seen these soil conditions, I've seen, you know, this amount of activity." And so that detailed information goes back to the asset managers and helps them with their longterm plan.

139. Mr. Bell commented on the need for the additional Transmission and Distribution employees related to the LTSP: "… without additional people, it's going to be

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[248] Exhibit B-1, p. 180 and p. 184, as revised by Exhibit B-1-2 dated May 16, 2011.

[249] Bell: T7, p. 1084, l. 10 to 1085, l. 8. Also, see Exhibit B-9, BCUC IR 1.57.1.

extremely difficult for us to just have the physical resources to go out and do a more in depth asset health review. So, it is going to force us to a shorter planning period for these assets."[250]

140. The FEU submit that the evidence in this proceeding demonstrates the need for the LTSP.[251] In order to facilitate the LTSP, the resources described above are required and should be approved.

(j) Conclusion on Operations (Distribution and Transmission)

141. The FEU have provided detailed evidence to support the Operations department budget for the test period. The costs should be accepted as filed.

C. CUSTOMER SERVICE

142. The Application provides an overview of the Customer Service department, its organization and required employees, followed by a description of the O&M requirements for 2012 and 2013 for each of the five functional areas of the department.[252] The Customer Service department is forecasting a decrease in expenditures for 2012 compared to 2011, driven by efficiencies realized through the new in-sourcing model. For 2013, costs are increasing primarily due to an increase in manual meter reading service costs as the benefits of joint gas/electric meter reads with BC Hydro end at the end of 2012.[253] O&M expenditures are all attributed to the Customer & Stakeholder Relations cost driver. Costs are allocated to each utility either directly or by using customer count as an allocation base.

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[250] Bell: T7, p. 1077, ll. 6 to 17.

[251] The LTSP is described in detail in the Application at pp. 335 to 343. A full account of O&M and Capital cost impacts of the LTSP across the FEU is provided in response to BCUC IR 1.57.1 (Exhibit B-9). The LTSP is also discussed below in *Part Eight: Capital Expenditures*.

[252] Exhibit B-1, beginning at p. 190.

[253] Exhibit B-1, p. 205.

143. Particular costs items that were probed in the course of information requests or cross examination are addressed below, including the Customer Care Enhancement Project and the deferral accounts for metering reading services and in-sourced customer care activities.[254]

(a) Customer Care Enhancement Project

144. The Customer Care Enhancement ("CCE") Project was approved by the Commission in February 2010 and is scheduled to "go live" in January 2012.[255] The FEU have been filing quarterly progress reports on the CCE Project in accordance with the Commission's CPCN.[256] Mr. Loski updated the Commission on the progress of the project during the hearing. In summary, the evidence demonstrates that to date the CCE project execution is a "good news story" for customers.

145. Cost control has been a key priority for all levels of management involved in the Project.[257] Mr. Loski expressed confidence that the new system will go live on January 1st, 2012.[258] Mr. Loski also explained that at the time of the oral hearing, of the over 300 new hires, there were only a few remaining staff to be hired[259] and that the second round of integration testing has been conducted and everything is on track.[260] The total cost of the CCE Project is projected to come in within the approved budget of the + /- 10 percent band of $115.5 million[261] and where any project spend greater or lower than the 10 percent band will be

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[254] Information requests did inquire into bad debt expense (e.g. Exhibit B-17, BCUC IR 2.72.1), but no issue was raised.

[255] Loski: T6, p. 1027, ll. 2-4.

[256] Exhibit B-12, BCOAPO IR 2.3.1.

[257] Exhibit B-12, BCOAPO IR 2.3.4 describes the following steps that were undertaken and continue to be followed to control and mitigate costs on the CCE Project: Well defined scope before commencement of the Project; a competitive RFP process was followed in selection of products and service providers for all major components of the Project; fixed price contracts; development of a detailed budget; hedge of USD exchange; robust project governance structure; robust change control process; and diligent Quality Assurance / risk management strategy.

[258] Loski: T6, p. 1028, ll. 11 to 20; T6, p. 1033, ll. 1-4.

[259] Loski: T6, p. 1033, l. 11 to p. 1034, l. 7.

[260] Loski: T6, p. 1034, l. 10 to p. 1035, l.13. For details on project testing see Exhibit B-12, BCOAPO IR 2.3.3.

[261] The project budget included an approximately $10 million contingency, which is an amount in a budget that is planned and expected to be spent: T6, p. 1030, l. 13-22.

shared equally with the FEU and customers.[262] The CCE Project is also expected to deliver all of the project benefits indicated in the CPCN Application as described in the response to CEC IR 1.3.4[263] with a lower O&M expense for 2012 and 2013 than compared to the O&M projection submitted with the CPCN Application.[264]

(b) Deferral Account – Meter Reading Services

146. FEU is seeking deferral account treatment for the actual meter reading expenditure that falls either above or below the forecast spend of $17.8 million in 2012 and $22 million in 2013.[265] The deferral account treatment is both reasonable and in the interests of our customers given the business uncertainties with respect to meter reading that the FEU face in the test period, which arise from two factors:

147. First, the FEU have entered into agreements for 2012 services with BC Hydro and Accenture and they are structured so that the FEU can take advantage of the benefit of joint gas/ electrics reads for as long as possible while BC Hydro continues with implementation of its smart meters (SMI). The FEU's forecast for 2012 services assumes that SMI will be completed by the end of 2012, consistent with BC Hydro's plans. This is a conservative estimate. To the extent that progress is slower than planned, the FEU will harvest savings with a higher proportion of the cost effective joint gas/electric reads. The FEU believe that it is more likely to be favourable rather than unfavourable; hence, a deferral account is beneficial to customers.[266]

148. Second, the FEU are engaged in a process to evaluate potential meter reading service providers for 2013 and beyond, and the provider has not yet been selected. The FEU

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[262] Exhibit B-8, CEC IR 1.3.1. It is noted that inaccurate project forecast / budget numbers for the CCE Project were provided in the schedules of the Application, and in the schedule supplied with response to BCUC IR 1.85.1 (Exhibit B-9). These have been corrected in the evidentiary update filed on September 12, 2011 (Exhibit B-21) which shows the correct Project costs. As a result of these inaccuracies, the BCUC staff arrived at an inaccurate schedule of Project costs for the question proposed in BCUC IR 2.41.1, where the total Project cost forecast was shown as $120 million. In the evidentiary update (Exhibit B-21), the schedules have been corrected and show the Project Cost forecast and budget to be a total of $115.5 million, which is equal to the approved level.

[263] Exhibit B-8. Loski: T6, p. 1040, l. 25 to p. 1041, l. 24.

[264] Loski: T6, p. 1036, ll. 13-15; Exhibit B-36, Undertaking No. 10.

[265] Exhibit B-1, p. 199-200 and 404.

[266] Exhibit B-9, BCUC IR 1.115.3.

forecast of $22 million for meter reading services is a reasonable basis for determining rates 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. However, if services are contracted at an amount lower than $22 million for 2013, the proposed deferral account will enable savings to flow back to customers.[267]

149. The FEU submit that the need for a deferral account for forecast metering expenses is demonstrated by the evidence and in the interest of customers. For ease of administration, the FEU are requesting this deferral account be combined with the in-sourced Customer Service activities deferral account discussed below.

(c) Deferral Account – In-sourced Customer Service Activities

150. As discussed above, the CCE Project is scheduled to go live on January 1, 2012 and the O&M costs to run the in-sourced model are forecast to be lower than anticipated in the CCE Project CPCN Application.[268] 2012 and 2013 will be the first years of operating under the new service model and technology platform. As such, there are unique circumstances involved in the transitioning to a new in-sourced service delivery framework that make it difficult to forecast customer service costs without the benefit of any direct experience with the new model. As such, the Companies are requesting a deferral account to capture actual expenditures that differ from the 2012 ($28.6 million) and 2013 ($27.9 million) forecast O&M expenditure levels for the ongoing operating costs of the in-sourced activities. The costs for the in-sourced activities for which the deferral account is sought are described in detail in Table 5.3-32 on page 203 of the Application.

151. Examples of uncertainties that may result in cost variances during the first years of operation that are largely beyond the FEU's control are described in BCOAPO 1.5.3 and include:[269] the time required to stabilize the new system processes; how fast new staff members become proficient in performing their new roles; the rate of customer adoption of

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[267] Exhibit B-9, BCUC IR 1.115.3. Exhibit B-8, CEC IR 1.3.6.
[268] Exhibit B-1, p. 203.
[269] Exhibit B-6, BCOAPO IR 1.5.3.

alternative communication channels; and, call volume fluctuations. Increased experience and familiarity gained during the first few years of operations will enable the FEU to better understand the impact of these uncertainties both in the way of incremental costs and potential savings, and enable the Companies to forecast operating costs under the new service model with greater confidence in future Revenue Requirement Applications. [270]

152. As discussed in response to BCOAPO IR 1.5,1,[271] a number of metrics will be in place for stakeholders to assess the costs incurred in 2012 and 2013. The FEU will continue to report on the existing customer service metrics included in the Service Quality Indicators that have been in place since 2003, for both the 2012 and 2013 forecast years. The FEU plan to provide a quarterly update to the Commission of customer service performance with the in-sourced operating model during the first two years of operations.[272] In addition, the FEU will evaluate the appropriateness of the existing service metrics and develop additional service metrics, such as cost per interaction and first call resolution, during the first year of operations.[273]

153. The FEU submit that given the uncertainties around the forecast of in-sourcing O&M costs for 2012-2013, a deferral account is appropriate and in the interest of customers.

154. The FEU have proposed that one deferral account be used for the in-sourced customer service costs and the meter reading costs as this provides ease of administration. The Companies plan to track the two cost components separately and the FEU will have the ability to report upon the two cost components.[274]

D. ENERGY SOLUTIONS AND EXTERNAL RELATIONS

155. The Energy Solutions and External Relations ("ES&ER") department consists of the following functional groups: Market Development, Resource Planning and Market

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[270] Exhibit B-6, BCOAPO IR 1.5.3.

[271] Exhibit B-6.

[272] Exhibit B-12, BCOAPO IR 2.2.1, and Exhibit B-6, BCOAPO IR 1.5.1.

[273] Exhibit B-1, p. 204. Exhibit B-6, BCOAPO IR 1.5.1

[274] Exhibit B-9, BCUC IR 1.115.4 and Exhibit B-6, BCOAPO IR 1.5.2.

Assessment, Community, Aboriginal and Government Relations, Communications and Energy Solutions. The Application describes the responsibilities of the department, its organizational structure and provides an overview of O&M expenditures and required employees.[275] The Application then provides a review of 2010 actuals to forecast, 2011 projections and 2012 and 2013 forecasts by cost driver for each utility. The Energy Solutions group, on a cost per customer basis, has been roughly tracking inflation since 2007. Spending will be essentially tracking inflation in 2012 and 2013 ($1.4 million labour inflation on existing staffing and general inflation over the two years), with the exception of new investment in Long-Term Resource Plan ("LTRP") development, the Biomethane program, and safety messaging.[276] The evidence relating to each of these three initiatives is set out below.

(a) Long-Term Resource Plan

156. The FEU are seeking an additional $1.2 million in 2012 and a further $300 thousand in 2013 related to the LTRP development. This request is in direct response to the Commission's directives to the FEU in its decision on the FEU's 2010 LTRP (Commission Order No. G-14-11).[277] The Commission Decision directed the FEU to include in its next LTRP, amongst other items, a 20-year vision and information and analysis related to EEC planning and the impacts of new initiatives on GHG reduction targets.[278] The requirements placed on the FEU by the Commission's decision are both broad and substantial, entailing extensive additional work for which the FEU does not currently have the capacity to complete.[279]

157. Mr. Bennett elaborated on the additional customer and demand forecasting work required:

> MR. BENNETT: A: Well, I -- the type of forecasting that this is referring to was discussed in the resource plan. And it's really taking the demand forecast to a different level, where you get into being able to forecast the usage mix within

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[275] Exhibit B-1, beginning on p. 206.

[276] Exhibit B-1, Section 5.3.8.5; Stout: T5. p. 800, l.19 to 801, l. 1.

[277] Exhibit B-1, pp. 215-217.

[278] The relevant extracts of the Decision are provided in Exhibit B-9, BCUC IR 1.68.1.

[279] Exhibit B-9, BCUC IR 1.68.1; Exhibit B-17, BCUC IR 2.32.1, 2.32.2. to 2.32.5.

> the houses, rather than just looking at simple customer additions and use per customer, which is what our current focus is. And that's what drives our costs. It's really getting to understanding what -- how gas is used within residences, and how it would change over time.
>
> And we did, in the resource plan, just a sample of how that might look for the Lower Mainland Region, and presented that in the resource plan. So it's a different level of forecasting than what we require for doing our short-term forecasting that we do right now, for revenue requirements purposes.[280]

The FEU currently undertake a degree of review of market developments, but "not the same kind of analysis that would be needed for the resource plan to provide the information that stakeholders were looking for, stakeholders and commissioners were looking for."[281] .

158. Mr. Bennett underscored that the ability to assess data and engage in more sophisticated long-term forecasting in the manner contemplated by the Commission's LTRP directive is becoming increasingly important as the market has become more complicated.[282] Although the currently available information is appropriate for the revenue requirements forecasts because it is a short-term forecast, the long-term impacts of trends in energy use and supply are significant and should be understood.[283]

159. The requested funding includes the cost of seven additional FTEs to perform the additional work on the LTRP and funding for studies to support the work.[284] The $1.5 million consists of $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.[285]

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[280] Bennett: T6, p. 911, l. 14 to p. 912, l. 14. See also Bennett: T6, p. 909, ll.9-16.

[281] Bennett: T6, p. 912, l. 15 to p. 913, l.9.

[282] Bennett: T5, p. 735, l. 21 to p. 736, l. 15.

[283] Bennett: T5, p. 736, ll. 8-15.

[284] Exhibit B-9, BCUC 1.66.1; Stout: T5, p. 799, l. 11 to p. 800, l.14; Exhibit B-17, BCUC IR 2.32.1.

[285] Exhibit B-9, BCUC IR 1.66.1.

160. The way in which the LTRP is developed presently is for a planning manager to coordinate input from 30 to 40 employees across the FEU; there is no centralized planning function. The input of those employees is still going to be required, but the new responsibilities under the Commission's directive require a more centralized planning initiative and greater time and resource commitment.[286] The additional staffing will be employed to develop new end use forecasting methods, prepare and report on new forecasts, and compare new and traditional forecasting methods and processes.[287] In the Application, the FEU have set out each directive of the Commission in the 2010 LTRP Decision and a description of the corresponding resources required to fulfill that direction. In information requests, the FEU reiterated this table twice to include further details including the specific reference and quote from Commission Order No. G-14-11,[288] and the approximate skill sets of each of the employees required to undertake the tasks needed to meet the Commission directives.[289]

161. A number of information requests inquired into existing skill sets at the FEU (including all those hired since 2009) and seemed to suggest that the new LTRP requirements could be met by existing staff.[290] The additional staff resources required to address stakeholder feedback and meet the Commission directives contained in the Commission decision on the 2010 Long Term Resource Plan are primarily due to the amount of additional work load that these directives require and not, for the most part, because the necessary skill sets do not already exist somewhere within the FEU today.[291] Mr. Bennett stated: "Well, I would say that they have the skill-sets, but they don't have the capacity. They're fully employed doing the things that they do now."[292] The seven FTE will be fully engaged in the work required to address the Commission's directive regarding long-term resource planning.[293]

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[286] Bennett: T6, p. 916, l. 18 to p. 918, l. 18.

[287] Exhibit B-17, BCUC 2.32.1.

[288] Exhibit B-9, BCUC IR 1.68.1.

[289] Exhibit B-17, BCUC IR 2.32.1.

[290] Exhibit B-17, BCUC IR 2.32.2. to 2.32.5.

[291] Exhibit B-17, BCUC IR 2.32.1

[292] Bennett: T6, p. 912, ll. 12 to 14.

[293] Bennett: T6, p. 916, ll. 11-15. Bennett: T6, p. 918, l. 19 to p. 920, l. 3. Mr. Bennett also explained in that passage why it is important to develop that capacity internally, rather than outsouce it.

(b) Safety Messaging

162. The 2012 incremental funding requested by FEI and FEVI for public safety education is $900 thousand, with a further $100 thousand requested in 2013.[294] This additional spending will be targeted at: 1) increasing the public's understanding of safety issues and appropriate actions pertaining to natural gas odour; and 2) improving excavation diligence and reducing third party damages to the natural gas system.[295] The reasons supporting additional safety messaging are several.

- First, current gas odour recognition and response safety awareness levels are currently low and awareness levels of at least 50 percent (of people who can recall our safety message without assistance) are targeted.[296] The number of instances of third-party damage to FEI's underground assets remains high across our service territory; 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.[297]

- Second, 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

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[294] Exhibit B-1, p. 213-214 and 218; Stout: T6, p. 940, ll. 11-16. Due to the timing required for ramp-up of safety messaging activities, Mainland estimates that the incremental cost in 2012 will be slightly less than the annual amount being requested for 2013.

[295] Exhibit B-17, BCUC IR 2.31.1.

[296] Exhibit B-1, p. 214.

[297] Exhibit B-9, BCUR IR 1.65.1.

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.[298]

- Third, the FEU's safety education programming is a critical part of the Mainland natural gas Safety Management Plan, a key requirement of the CSA Oil and Gas Systems Standard Z662-07. Section 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".[299] A properly funded public safety education program is good operating practice and will meet the requirements of Section 10.2 of the standard.

163. The FEU respond to approximately 1,400 third-party damages and 20,000 gas odour calls annually. Each of these instances could be a potentially dangerous situation. Over a five-year period approximately 10% of the FEU's customers have called because they are aware that gas odour is a concern which requires an immediate response. The FEU strongly believe in the educational approach that will reinforce awareness of both natural gas odour recognition and the appropriate response required.[300]

164. The FEU therefore submit that the increase in safety messaging funding is prudent and should be approved.

(c) Community Investment

165. The FEU have budgeted community investment expenditures as part of O&M for 2012 and 2013. In this section, we address the proper treatment of community investment expenditures. A number of IRs and questions appeared to suggest that community investment generally was intended to benefit the shareholder, rather than customers. The FEU submit,

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[298] Exhibit B-9, BCUR IR 1.65.1.

[299] Exhibit B-9, BCUC IR 1.64.1.

[300] Exhibit B-17, BCUC IR 2.31.1.

however, that community investment is a cost of providing service to natural gas customers and should be fully recoverable in rates.

166. The Community Investment budget for FEI and FEVI for 2012 and 2013 is set out in response to BCUC IR 1.61.1. The total budget is $500 thousand for each of 2012 and 2013 and is dedicated to three laudable programs:[301]

- **Employee Give Where You Live Program:** The FEU top up employee donations by 50 per cent when they give during the FEU's annual Giving campaign or through the FEU's payroll deduction program. This program aligns the FEU's community programs with employee volunteer recognition and results in a positive incremental impact on the communities that the FEU 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.

- **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.

167. The key influences and cost drivers of the FEU's community involvement spending are business-oriented and bring value to customers. The objectives of these investments in the communities in which FEU operate include:[302]

- create community partnerships that improve both the FEU's ability to work in these communities and the effectiveness of those activities;

[301] The following are descriptions from Exhibit B-9, BCUC IR 1.61.1.

[302] Exhibit B-17, BCUC IR 2.28.1.

- improve the pride that the FEU's employees take in working for the FEU and thus increase productivity and attract high quality employees;
- increase or maintain the loyalty and trust of customers; and
- share information about the energy services offered by the FEU and activities conducted in the communities served by the FEU, which can include information about programs and safety.

168. As the sponsorships and donations enhance the relationship between the utility and the communities it serves, in turn, it can affect the expenses associated with public consultation that are necessary as part of the utility's operation.[303] The benefits associated with community investment defy easy quantification, but Mr. Stout explained the impact of such investments as follows:[304]

> The community investment is something that you do -- we do, and view it as part of helping facilitate doing business, running our operations and improving our ability to get projects moved along in a more timely fashion in certain areas, dealing with issues as they come up. And that's been my experience here and in other companies that I've worked on, in that that is the value and the reason that you do, a lot of times, community investment.

Mr. Thomson noted examples of projects such as the Mt. Hayes LNG facility and Southern Crossing Pipeline (SCP).[305]

169. The FEU's support for local government, association and community activities is a normal part of doing business in communities throughout the Province.[306] It is expected by customers, as evidenced in the FEU's regular customer service surveys and the significant number of requests for funding and support received annually from a variety of community service providers and business associations.[307]

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[303] Exhibit B-17, BCUC IR 2.28.1.

[304] Stout: T5, p. 812, l. 14 to p. 813, l. 2.

[305] Thomson: T3, p. 454, l. 13 to p. 455, l. 15.

[306] Thomson: T3, p. 455, ll. 14-15; T5, p. 812, ll. 21 to 24.

[307] Exhibit B-17, BCUC IR 2.26.1.

170. 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 cooperation 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.[308]

171. The FortisBC name is associated with events and sponsorships. However, the FortisBC name is associated with the provision of regulated energy services, and the shareholder only benefits through the allowed return on equity. In other words, the shareholder only prospers when customers prosper from a healthy utility, which is the same as with any utility investment.

172. The accounting and regulatory treatment of the acquisition premium paid by Fortis Inc. for Terasen Inc. - the premium to book value was reflected as goodwill for accounting purposes and did not flow to customers - is a "red herring" in the context of community investment.[309] "Goodwill" is simply the accounting entry used to record a premium to book value that cannot be reflected in rate base. The notion that Fortis paid a $706 million premium for the shares of Terasen Inc. in order to obtain a Terasen brand that had been strengthened through years of modest community investment strains credulity and is belied by the fact that Fortis subsequently changed the name of the Terasen companies to FortisBC. The premium paid by Fortis had nothing to do with shareholders benefitting from community investment.

173. In short, 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.

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[308] Exhibit B-9, BCUC IR 1.61.2.1.

[309] Thomson: T4, p. 504, ll.4-22.

(d) Biomethane Service Offering

174. The FEU are requesting approximately $400,000 for the Biomethane program.[310] Messrs. Stout and Bennett described the launch of the program, and the success that the Companies have had to date adding customers to the program. The Companies are planning on launching the commercial rate classes next year, and there has been significant interest there that the Companies are targeting.[311]

175. The ES&ER costs related to the Biomethane Service Offering for the period 2012 and 2013 were those discussed in the Biomethane Application and approved for 2010 and 2011 in Commission Order G-191-10. For 2010 and 2011, the costs were recorded in the 2010-2011 Biomethane Program Costs deferral account. The Biomethane Application articulated that these costs were expected to continue into 2012 but did not request specific approval of costs for 2012. In this Application, FEI is requesting approval of these costs for 2012 and 2013, inclusive of the incremental amount for inflation. The forecast assumes that the offering will continue into 2012 and 2013, with inflation as the force driving small incremental increases.[312]

176. Information requests from Commission staff suggested that it was inappropriate for Biomethane education to include any element of “marketing” or “advertising.” The FEU submit that such a suggestion has no basis in the Commission Order approving the Biomethane Application and that all of the education costs are appropriately recovered in rates.

- The key elements of the FEU’s customer education objectives for biomethane include education and promotion of the biomethane service offering. Just like any new product, the FEU expect the initial communication activities to generate interest and acceptance amongst the early adopters and innovators.[313]

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[310] Exhibit B-1, Application, p. 217. Actual figures are $416,384 in 2012 and $414,512 in 2013.

[311] Stout and Bennett: T5, p. 757, l. 1 to p. 758, l. 24; Bennett: T5, p. 764, l. 11 to 765, l. 9.

[312] Exhibit B-1, p. 212 and p. 217; Exhibit B-9, BCUC IR 1.180.1.

[313] Exhibit B-1, Attachment J, p. 2; Exhibit B-9, BCUC IR 1.177.5 and 1.177.10.

- The customer education plan is being executed in the manner in which it was described in the Biomethane Application. FEI discussed at length in the Biomethane Application and in response to BCUC IRs the need for educational, promotional, awareness and retention components in the customer education plan.[314] For instance, the Biomethane Application stated that two of the objectives of the plan were to "stimulate interest and participation in the program" and "maintain participation and support for the program."[315] The customer education budget set out in the Application included amounts for "Direct marketing". BCUC information requests demonstrated an awareness of that the program included an element of marketing, as it included questions about the costs of promotion and the effectiveness of "generic advertising."[316]

- Order G-194-10 approved FEI's proposed costs associated with making the biomethane service offering available to all customers, which included customer education with some marketing, to be recoverable from all non-bypass customers. There was no direction in Commission Order G-194-10 to segregate any element of the customer education costs.

- The Decision states that "…the Commission Panel agrees with FEI and the CEC that it is in the long term interest of all FEI utility customers that new initiatives contribute to retention and the addition of throughput in the system, which will result in system costs being spread over a larger base."[317] In order to generate the long-term benefits for customers, education and advertising are both necessary to create awareness, stimulate interest, encourage and maintain participation in the program. As biomethane has not previously been available

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[314] Exhibit B-17, BCUC IR 2.89.1 and Attachment 89.1.

[315] Exhibit B-17, Attachment 89.1, p. 56 of Biomethane Application.

[316] Exhibit B-17, Attachment 89.1, and BCUC IRs 2.18.1 to 2.18.5.

[317] Decision accompanying Order No. G-194-10, p. 51. Exhibit B-17, BCUC IR 2.89.7.

as an energy source in B.C., customers must first be made aware of its introduction to the marketplace and its environmental benefits.[318]

177. In short, the Biomethane education costs were approved by the Commission and are necessary for the Biomethane program's success to the benefit of all customers. No questions related to the Biomethane education costs were pursued during the oral hearing.

(e) Conclusion on ES&ER

178. The FEU submit that the forecast costs for the ES&ER department are reasonable and in line with past expenditures and should be approved as filed.

E. OPERATIONS ENGINEERING

179. The Operations Engineering department is responsible for implementation and maintaining compliance in the areas of Project Management, Geographic Information Systems, System Integrity, Corrosion, Property Services, System Planning, the Gas Lab, and Location Records. The department is forecasting reasonable increases for 2012 and 2013. An overview of the department, its organization, historical expenditures and forecast expenditures is provided in the Application at pages 226 to 233.

180. There were very few questions related to the Operations Engineering department forecast O&M expenses. The three areas that were probed in the first round of IRs, but were not otherwise pursued, are discussed below.

(a) CSA S250 Mapping Standard

181. FEI requires incremental funding to be able to bring its GIS system into compliance with CSA S250 Mapping Standard for Underground Utilities, which was published in September 2011.

182. The new standard "will specify the mapping requirements for the recording and depiction of underground utility infrastructure, and related appurtenances at or near grade and

[318] Exhibit B-17, BCUC IR 2.89.2.

will apply to proposed existing, abandoned in-place, retired, or reserved for future use, underground utility infrastructure”.[319] The CSA S250 Mapping Standard introduces a new step in the FEU’s GIS process that will require the FEU 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. It also drives 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.).[320]

183. An incremental $222 thousand in 2012 is required to fully fund a GIS Drafter Leader and required land base mapping, drafting interface and drawing management activities in compliance with this new standard. The 2013 budget will be reduced by $50 thousand that is associated with a one-time consultant required in 2012.[321] A detailed breakdown of the FEU’s existing and proposed mapping staff and O&M requirements is provided in response to BCUC IR 1.70.2.[322]

(b) Consultation and Notification Regulation

184. Funding is also required to comply with the new Consultation and Notification Regulation (“CNR”) under the *Oil and Gas Activities Act* (“OGAA”). The new regulation 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 under the former BC *Pipeline Act*.[323] The Oil and Gas Commission has also created an extensive and step-by-step Consultation and Notification Manual to ensure that the requirements are clearly understood and followed by

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[319] Exhibit B-1, p. 231.
[320] Exhibit B-9, BCUC IR 1.70.1.
[321] Exhibit B-1, pp. 231-232.
[322] Exhibit B-9.
[323] Exhibit B-1, p. 231 and Exhibit B-9, BCUC IR 1.71.1.

industry.[324] A review of this manual demonstrates the rigour of the new consultation requirements.

185. An additional $103 thousand in 2012 to be maintained in 2013 is required to fully fund an employee for an OGAA Project Coordinator position. Given the extensive nature of the new requirements, existing staff within the FEU do not have available workload capacity to take on the extent of additional work needed to meet the new OGAA requirements.[325]

(c) Long-Term Sustainment Plan

186. Operations Engineering plays a role in facilitating the FEU's Long-Term Sustainment Plan.[326] Funding of $242 thousand in 2012 and $135 thousand in 2013 is required to provide administrative and support resources to assist in the development of project cost estimates and in the preparation of feasibility studies that are a precondition for any project approval.[327] The O&M and capital costs for the Long-Term Sustainment Plan are summarized in BCUC IR 1.57.1. The Long-Term Sustainment Plan is addressed more generally below in the capital expenditures section.

(d) Conclusion on Operations Engineering

187. The FEU submit that the forecast O&M in the Operations Engineering department is reasonable, required for the prudent operation of the FEU and should be accepted as filed.

F. OPERATIONS SUPPORT

188. The Operations Support department is described in the Application, along with historical, projected and forecast O&M, at pages 233 to 240 of the Application. Operations Support provides meter asset management, technical analysis, field support and supply chain

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[324] Exhibit B-9, BCUC IR 1.71.1. The Manual is available online at: http://bcogc.ca/document.aspx?documentID=909&type=.pdf

[325] Exhibit B-1, p. 232; Exhibit B-9, BCUC IR 1.71.1; Exhibit B-17, BCUC IR 2.35.1.

[326] Note the distinction between the Long Term Sustainment Plan and the Long-Term Resource Plan, a distinction which was addressed at the hearing in cross-examination.

[327] Exhibit B-1, p. 232; Exhibit B-9, BCUC IR 1.57.1.

services.[328] The O&M required to provide these services is increasing because of the increase in activities and the rising cost of parts, and is required in order to continue to provide the level of service required to ensure the safe, reliable and cost effective operations. There were very few questions related to the Operations Support O&M forecast. The issues canvassed (in IR round one only) related to meter reading and support for Biomethane and NGV.

(a) Compliance with Measurement Canada Requirements

189. Operations Support requires $65 thousand for two additional resources to be hired in the second half of 2013 to ensure compliance with Measurement Canada's more rigourous meter sampling requirements. In 2014, Measurement Canada, the federal agency that regulates FEU's meter fleet, is legislating sampling plan SS06 which is a more rigourous standard on meter sampling, testing and accuracy tolerances than the existing standard. Mr. Bell explained Measurement Canada's new requirements.[329] In particular, SS06 will result in a 50 percent increase in the number of meter samples.[330] Even with the two additional employees, in 2014 the number of meter samples per FTE supporting meter samples will be higher than it has been since 2009.[331] This demonstrates the FEU's commitment to do more with less.

(b) NGV and Biomethane Service Offerings

190. Operations Support 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.[332] This represents the additional procurement work required

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[328] Exhibit B-1, p. 233.

[329] Bell: T7, p. 1210, l. 10 to p. 1213, l. 26.

[330] Exhibit B-1, pp. 238-239.

[331] Exhibit B-9, BCUC IR 1.73.2.

[332] Exhibit B-1, p. 239 and Appendix J, Table J-2, p. 8. 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). Revised Tables are provided in response to BCUC IR 1.181.2, Exhibit B-9.

to support the biomethane and NGV programs.[333] These requirements are not affected by the discontinuance of the incentives for NGV.[334]

191. The FEU submit that it is most appropriate to recover these Biomethane program costs in the forecast period to match the time in which they are incurred. Biomethane is a component of the FEU's natural gas business and operations and should be treated consistent with other forecast costs that apply to all customers.[335]

(c) Conclusion on Operations Support

192. The FEU submit that the Operations Support forecast is just and reasonable and should be accepted as filed for the purpose of calculating 2012-2013 rates.

G. DEPARTMENTS WITH NO ISSUES RAISED

193. There were a number of departmental O&M forecasts to which no material questions were directed. These departments are listed below.

(a) **Energy Supply and Resource Development ("ESRD"):** The forecast O&M for the ESRD department is set out in pages 185 to 190 of the Application. The ESRD department is forecasting only minor increases for FEI and no incremental costs for FEVI. The incremental resources required for ESRD are not involved in NGV, Thermal Energy Services or Biomethane service offerings and are also not expected to be engaged in LTSP-related activities.[336]

(b) **Information Technology:** Forecast O&M costs for the Information Technology (IT) department are set out in the Application at pages 218 to 226. No questions were directed at the 2012-2013 IT O&M forecast.

[333] Exhibit B-9, BCUC IR 1.181.1.

[334] Exhibit B-21, Evidentiary Update, p.3.

[335] Exhibit B-9, BCUC IR 1.187.1.

[336] Exhibit B-9, BCUC IR 1.58.2 and Exhibit B-17, BCUC IR 2.25.1.

(c) **Facilities:** The Facilities department's organizational structure and function and historical, projected and forecast O&M is described at pages 240 to 245 of the Application. No questions were directed at the 2012-2013 Facilities O&M forecast.

(d) **Human Resources:** The Human Resources department's organizational structure and function and historical, projected and forecast O&M is described at pages 245 to 251 of the Application. No questions were directed at the 2012-2013 Human Resources O&M forecast.

(e) **Environmental Health and Safety (EH&S)**: The Environmental Health and Safety (EH&S) department's organizational structure and function and historical, projected and forecast O&M is described at pages 251 to 256 of the Application. EH&S is forecasting minor cost increases for 2012 and 2013. The only question with respect to these expenses was whether the $36 and $56 thousand in funding related to disaster recovery in 2012 and 2013, respectively, overlapped with the disaster recovery systems installed as part of the CCE Project. The EH&S funding does not overlap, but is related to equipping alternate workspaces for Surrey Operations Centre employees in the event of a disaster.[337]

(f) **Finance and Regulatory Affairs:** The Finance and Regulatory Affairs department's organizational structure and function and historical, projected and forecast O&M is described at pages 256 to 261 of the Application. No questions were directed at the 2012-2013 Finance and Regulatory Affairs O&M forecast.

(g) **Corporate:** The Corporate department's organizational structure and function and historical, projected and forecast O&M is described at pages 261 to 266 of the Application.[338] See below for Corporate and Shared Services.

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[337] Exhibit B-9, BCUC IR 1.75.1.

[338] Exhibit B-1-3, Updated Application pp. 263 to 265.

H. CAPITALIZED OVERHEADS

194. The FEU have proposed to maintain the 14 percent capitalized overhead rate that was agreed to as part of the approved 2010-2011 NSAs for FEI and FEVI and subsequently approved for Fort Nelson and FEW. Ms. Roy and Mr. Thomson spoke to the 14% rate compared to the 8% rate indicated in the study filed in the 2010-2011 RRAs for FEI and FEVI. As they discussed, the overheads capitalized rate may be higher than what a current study would support, but it is lower than what it has been in the past and ameliorates rate impacts for customers.[339] As such, the FEU submit that the 14% capitalized overhead rate remains appropriate and should be accepted for use in 2012 and 2013.

I. CORPORATE AND SHARED SERVICES

195. Section 5.4.18 of the Application describes the corporate services provided by Fortis Inc. and FortisBC Holdings Inc. (FHI) to the FEU and how the FEU share costs amongst each other and with FortisBC Inc.. The relationship between the FEU, FHI and FortisBC Inc. is generally unchanged from the time of filing of the 2010/2011 RRAs for FEI, FEVI and FEW. As in 2010 and 2011, the Corporate Services are contracted to FEU through FHI. The approach and methodologies used for corporate and shared services are the same as those reviewed and validated by KPMG for the 2010/2011 RRA. The shared services across the FEU are similar to what was filed in the 2010/2011 RRA and reflect the same cost drivers. The Shared Services Agreements between FEI and FEVI and FEI and FEW are unchanged from the agreements filed in the 2010/2011 FEI and FEVI RRAs.[340]

196. While information was requested about Corporate and Shared Services,[341] no material issue was raised. The $0.5 million allocation to Thermal Energy Services is considered below in Part Eight of this submission.

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[339] Roy: T5, p. 693, l. 5 to p. 696, l. 6.

[340] Exhibit B-1, pp. 267 to 278, as amended by Exhibit B-1-3.

[341] See Exhibit B-9, BCUC IR 1.76.1, 1.77.1 1.79.1, 1.79.2; Exhibit B-17, BCUC IR 2.36.1; Exhibit B-6, BCOAPO IR 1.27.1 to 1.29.1; Exhibit B-8, CEC IR 1.12.1 to 1.12.3.

J. CONCLUSION ON COST OF SERVICE: O&M EXPENSE

197. The FEU's 2012 and 2013 O&M forecasts, which are increasing by 7.6 percent in 2012 and 4.1% in 2013, reflects the changes in operating requirements that are anticipated over the forecast period associated with labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability. The O&M forecast is supported by the evidence and should be approved as sought.

PART SIX: COST OF SERVICE: DEPRECIATION AND AMORTIZATION

A. INTRODUCTION

198. In this Part, we address the depreciation rates reflected in the revenue requirements. Depreciation rates are set to provide a reasonable assurance of the recovery of the invested capital over the useful life of the assets from the customers who take service.[342] As most utility assets are long-lived, accepted practice is to update depreciation rates every few years based on new information about asset service life. The FEU retained Mr. Larry Kennedy of Gannett Fleming to provide independent expert advice regarding the appropriate depreciation rates to be reflected in 2012 and 2013 rates.

199. The proposed depreciation rates, which contribute materially to the proposed delivery rate increases, reflect Mr. Kennedy's recommendations[343] based on the best estimate of the life of utility assets. The depreciation rates also incorporate an estimate of net negative salvage determined based on the most widely accepted approach in the industry, which was endorsed by Mr. Kennedy. Consistent with past studies, the depreciation rates developed by Mr. Kennedy also accounted for a provision to continue recovering "asset losses", or unrecovered depreciation, from years prior to 2010 that are a by-product of the group depreciation methodology. The FEU submit, for the reasons described below, that the proposed depreciation rates, proposed treatment for the recovery of net negative salvage, and the inclusion of unrecovered depreciation (or asset losses) in depreciation rates are appropriate. The depreciation rates should be approved by the Commission.

200. This Part sets out the evidence supporting:

- the robust process used to determine depreciation rates;
- the reasonableness of the proposed approach for recovering net negative salvage as a cost of service; and

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[342] Thomson: T3, p. 466, ll. 7-11; Kennedy: T3, p. 465, ll. 6-11.

[343] The FEU's proposals with respect to depreciation, negative salvage and unrecovered deprecation are set out in the body of the Application at pp. 278 to 292. They are supported by Gannett Fleming's Depreciation Study (Appendix K-1), the Asset Retirement Obligations Report (Appendix K-2) and Asset Loss Report (Appendix K-3).

- recovery of "asset losses" in depreciation rates.

B. DEVELOPING DEPRECIATION AND NEGATIVE SALVAGE RATES

201. This section summarizes the evidence on the process used to determine depreciation and net negative salvage rates. The process was guided throughout by Mr. Kennedy, a recognized expert in this area. [344] This approach of having utility staff work with an external depreciation specialist to determine depreciation and net negative salvage rates is consistent with industry practice and reinforces the reasonableness of the results.

(a) The Process Employed to Develop Depreciation Rates

202. As indicated previously, depreciation rates are set to provide a reasonable assurance of the recovery of invested capital over the useful life of the assets from the customers who take service.[345] The investment that must be recovered is a known amount, and the exercise of determining depreciation rates involves developing life estimates by looking at historical transactions and comparisons to peers. The life estimate is revisited many times over the life of the asset class.[346]

203. Mr. Kennedy's Depreciation Study details the collaborative process used in determining the proposed depreciation rates.[347] The involvement of FEU staff was essential as they had the greatest familiarity with the assets. Mr. Kennedy brought industry-wide expertise and an independent validation of the depreciation rates. Mr. Kennedy's role included reviewing the FEU's assets and retirement transactions, conducting operational interviews with the FEU staff, and comparing the results to the FEU's industry peers. The FEU then reviewed Mr. Kennedy's recommendations for accuracy, reasonableness and applicability to the assets.[348]

204. Having determined appropriate depreciation rates, Mr. Kennedy adjusted the rates to factor in the recovery of any existing retirement losses that may be included in the

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[344] Kennedy: T2, p. 275, l. 8 to p. 286, l. 10.

[345] Thomson: T3, p. 466, ll. 7-11; Kennedy: T3, p. 465 ll. 6-11.

[346] Kennedy: T4, p. 554, l. 21 to p. 555, l. 3.

[347] Exhibit B-1, Appendix E-1.

[348] Exhibit B-9, BCUC IR 1.136.2.

accumulated depreciation account balance. The adjustment is designed to recover those losses over the remaining lives of the existing assets or asset classes.[349] This step is discussed further below.

205. The recommended depreciation and negative salvage rates that were the outcome of this process, and their impact on 2012 and 2013 delivery rates, are set out in Tables 5.4-1, 5.4-2, 5.4-3 and 5.4-4 of the Application.[350] As explained in the Application, the implementation of the recommended depreciation rates would change the average composite rate for FEI, FEVI and FEW from 3.0 percent, 2.6 percent and 2.2 percent to 3.1 percent, 2.6 percent and 2.4 percent, respectively. Total depreciation expense for FEI, FEVI and FEW would change approximately +$4.6 million, -$0.3 million and +0.03 million, respectively, due to changes in the depreciation rates.[351]

(b) The Process Employed to Develop Negative Salvage Rates

206. Net negative salvage reflects the cost of removing assets no longer in use, net of any salvage value. Net negative salvage is a legitimate cost of providing utility service and must be recovered from customers. The issue regarding net negative salvage is not *whether* it should be collected, but rather *when* it should be collected. Or, as Ms. Roy put it: "it's a timing issue".[352] The FEU are proposing to revert back to the recovery of net negative salvage through a separate component in depreciation rates. In this section, the FEU discuss how the net negative salvage rates were determined. The merits of the FEU's proposal to return to this traditional method, and its consistency with GAAP and the BCUC Uniform System of Accounts and industry practice, are discussed in a subsequent section.

207. The steps taken to develop the negative salvage rates are discussed in Mr. Kennedy's Depreciation Study, including a description of all factors considered for each of the

[349] Exhibit B-9, BCUC IR 1.136.2.
[350] Exhibit B-1, pp. 284 and 289.
[351] Exhibit B-1, p. 283.
[352] Roy: T3, p. 348, l. 2.

accounts where a net salvage recommendation is made.[353] A detailed description of the process is also provided in Exhibit B-1, BCUC IR 1.136.1 (pp. 446-447) and, in his testimony, Mr. Kennedy provided a detailed explanation of the calculations undertaken in developing net negative salvage estimates.[354]

208. In developing net salvage estimates, Mr. Kennedy has applied his professional judgment and considered factors such as: the FEU's actual history of retirements, which can be given the most weight in accounts where more history is available; the experience of other utilities, or "peer analysis"; and, discussions with operations personnel in terms of whether they, for instance, remove plant or abandon it in place.[355] The use of professional judgment 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 judgment has been accepted in a number of regulatory jurisdictions across Canada. For example, the historical net salvage percentages approved by the Alberta Utilities Commission incorporate net salvage percentages that include the use of professional judgment for both AltaGas Utilities and ATCO Gas.[356]

209. Estimates are updated every three to five years, which is the mechanism for ensuring that the removal costs that are being collected from customers today are reasonable and reflect the most recent experience of the utilities as far as actual removal costs and forecasts for the future.[357] This process ensures that anything in excess of the amount required is returned to customers over the life of the asset class through adjustments to the net negative salvage rate.[358]

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[353] Exhibit B-1, Appendix E-1. See pp. II-31 to II-47. The statistical analysis used by Gannett Fleming is provided at p. V-2 forward. The source data is provided in Exhibit B-9, BCUC IR 1.136.1.

[354] Kennedy: T4, p. 536, l. 21 to 537, l.25.

[355] Kennedy: T3, p.351 l. 12 to p. 352, l. 22; p. 354, l. 24 to p. 355, l. 5; BCUC IR 1.136.4, discussed by Mr. Kennedy at T4, p. 557 l. 18 to p. 559, l. 12.

[356] Exhibit B-9, BCUC IR 1.139.1.

[357] Roy: T3, p. 345, ll. 17 to 26; Kennedy: T3, p. 353, ll. 16-20; Kennedy: T4, p. 554, ll. 4-11.

[358] Roy and Thomson: T4, p. 538, l. 12 to 539, l. 23.

210. In a series of information requests, Commission staff cited NEB Decision RH 2-2008 and referenced the factors used by the NEB in assessing negative salvage rates, such as the concept of economic life and economic planning horizons forming a significant component of the depreciation studies. As explained in response to BCUC IR 1.137.1, the approach outlined in the NEB's Reasons for Decision RH-2-2008, is not as applicable for the type of mass property accounts within the FEU system.[359] Unlike the NEB approach which is concerned with assets accounted for under a single-unit depreciation method, 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.[360] Therefore, the NEB Decision RH 2-2008 provides no guidance with respect to the calculation of negative salvage rates for the test period.[361]

(c) Variances From Forecast Depreciation Rates During the Test Period

211. The FEU forecast depreciation expense based on approved depreciation rates, and forecasts of the opening plant balances, plant additions and retirements. If the amount of actual depreciation expense in the test period exceeds the forecast, the Companies are not able to recover that difference. Only the actual depreciation expense will be recorded in accumulated depreciation.[362] This is the same treatment as the majority of other forecast items.[363]

212. Variances in depreciation expense during the test period are a distinct issue from the accumulation of asset losses, which are discussed below in Section C of this part of the Submission. Regardless of the depreciation rate that is forecast, approved and implemented,

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[359] Exhibit B-9, BCUC IR 1.137.1.

[360] Exhibit B-9, BCUC IR 1.137.8.

[361] Exhibit B-9, BCUC IR 1.137.8.

[362] Exhibit B-17, BCUC IR 2.44.3.

[363] Exhibit B-17, BCUC IR 2.75.6.1. Variances in depreciation expense are not usually of a material amount and tend to be favourable in some years and unfavourable in other years. See Exhibit B-17, BCUC IR 2.44.1 where variances are provided, along with explanations for those situations where material variances occurred.

the utility is still entitled to an opportunity to receive the return of its investment in assets over time.[364]

(d) Effect of Reducing Depreciation Rates for Short-Term Rate Impacts

213. Mr. Kennedy was asked whether there were alternative methodologies available for determining depreciation rates that might yield lower rates in the short-term. Mr. Kennedy's evidence was that short-term measures of this nature would transfer the burden to future years, perhaps as early as 2 to 3 years out. The magnitude of the current adjustment in depreciation rates is partly attributable to holding depreciation rates constant from 2004 to 2009. Mr. Kennedy indicated that "…if one of the goals is stable toll and a reasonably stable toll over the long term, I'm not sure there's anything out there that at least I'm aware of that would make sense."[365] He added that the approach being taken is "probably the most conservative, and conservative to the benefit of the toll payer approach that I think we could have taken."[366]

214. The FEU submit that it is in the best interest of customers in the long-term to reflect the best estimates of depreciation expense in 2012 and 2013 rates. The evidence in this proceeding shows that there has been a history of stakeholders, with Commission approval, deferring the updating of depreciation rates for the purposes of deferring rate impacts.[367] The full capital cost of system assets must still ultimately be recovered in rates, and rate impacts will compound over time.

(e) Conclusion on Depreciation and Negative Salvage Rates

215. The FEU submit that, like other highly technical areas, the estimation of depreciation and salvage rates is a discipline which is properly the subject of expert opinion. Mr. Kennedy's expertise in this area was unquestioned,[368] and no other expert was called to contradict his testimony. Neither information requests nor cross-examination cast doubt upon

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[364] Exhibit B-17, BCUC IR 2.75.6.1.

[365] Kennedy: T3, p. 463, l. 23 to p. 464, l. 26.

[366] Kennedy: T3, p. 465, ll. 6-11.

[367] e.g., Exhibit B-17, BCUC IR 2.74.12 and 2.74.14.2.

[368] Kennedy: T2, p. 275, l. 8 to p. 286, l. 10.

the depreciation and negative salvage rates put forward by the FEU. The evidence confirms that the depreciation and negative salvage rates calculated by Mr. Kennedy are reasonable. They should be accepted.

C. MERITS OF PROPOSED METHODOLOGY FOR RECOVERING NET NEGATIVE SALVAGE

216. As net negative salvage is a legitimate cost of service, stakeholder inquiries focused on the best methodology for recovering net negative salvage from natural gas customers. In this section, the FEU address the evidence supporting the proposed approach. The proposed approach is consistent with Mr. Kennedy's recommendation, the BCUC Uniform System of Accounts and GAAP, and is the generally accepted regulatory treatment across North America. There are a variety of benefits associated with the proposed approach, including equitable recovery from customers who benefit from the assets, rate stability, and transparency. The FEU submit, for the reasons described below, that the FEU's proposal to use the traditional approach to recovering net negative salvage should be adopted going forward.

(a) FEU's Proposal Consistent With Industry Practice, Uniform System of Accounts and GAAP

217. Until 2010, the FEU had recovered net negative salvage over the service life of the assets or asset classes as a component of depreciation rates (the "traditional approach"). The 2010-2011 RRA NSA provided that, for the test period, the FEU would recover forecast removal costs to be incurred in the test period, with variances from forecasts captured in a deferral account (the "pay as you go" approach).[369] The FEU agreed to work with a depreciation expert to study the methodologies available for recovering net negative salvage and present a recommendation in this Application. The resulting Asset Retirement Obligation Report considered the treatment of negative salvage in other jurisdictions, and identified four options for the collection of negative salvage: the traditional approach, "pay as you go", the Asset Retirement Obligations ("AROs") approach and a hybrid approach. The recommendation of the report, made in consultation with Mr. Kennedy, was to

[369] This history is canvassed at Exhibit B-1, pp. 278 to 282.

- revert to the traditional approach; and
- to continue to review regulatory assets to determine if any AROs must be recorded under GAAP, and, if so (at this time, no AROs have been identified for the Utilities),[370] to use the ARO methodology for regulatory purposes as well.

As described below, the proposed approach is the most widely accepted approach throughout North America, and confers a number of benefits.

Traditional Approach is Industry Standard

218. Mr. Kennedy and Ms. Roy confirmed that the traditional approach is the natural gas industry standard.[371] Mr. Kennedy indicated that although the "pay as you go" method is employed in some circumstances as a short term (typically negotiated) means of addressing rate spikes, he could not think of a natural gas utility that does not generally use the traditional approach proposed by the FEU.[372] FEI's and FEVI's use of the "pay as you go" approach in 2010 and 2011 was a negotiated outcome. Although the Commission approved a similar treatment in FEW's 2010-2011 RRA following an oral hearing process to maintain consistency with FEVI and FEI, the Commission Panel stated that it was "not convinced that the elimination of the negative salvage provision in the determination of the composite depreciation rate is appropriate on an ongoing basis."[373]

Benefit #1: Distributes Costs to Customers Equitably Over Time

219. A key benefit of the traditional approach is that it distributes costs equitably over time. Mr. Thomson and Ms. Roy characterized the customer equity issue as one of having customers that benefit from the use of an asset contributing to its removal cost. Mr. Thomson stated, for instance:

> We think it's more appropriate to collect that as we go, based on the reasonable estimation process that's employed, because that then matches the cost of

[370] Exhibit B-1, p. 288.

[371] Kennedy: T4, p. 532, l. 26 to p. 533, l. 20; Roy: T3, p. 423, ll. 18 to 25.

[372] Kennedy: T5, p. 712, l. 9 to p. 714, l. 3.

[373] Appendix A to Order G-138-10, p. 13 of 27.

> service over the life of the asset, and attempts to collect it from the people who have the benefit of that. [374]

220. By contrast, under the "pay as you go" approach, no funds would be collected from customers during the life of the asset, with the result that costs are not borne by the customers that obtained the benefit of the assets. Rather, the actual costs of abandonment are borne by customers who have not had use of the asset over its life. This raises issues of intergenerational equity between customers.[375]

Benefit #2: Improves Transparency and Accountability

221. One of the goals or attributes for an approach to net negative salvage is to improve the utility's accountability for negative salvage costs recovered from customers. The traditional approach, as proposed by the FEU, addresses this goal by tracking separately by asset class the resulting regulatory liability related to negative salvage liabilities and disclosing it as a separate line in rate base and in external financial reporting.[376] The FEU will be undertaking to review for reasonableness any entries recorded in the provision account on a quarterly basis.[377] The provisions would be subject to the same audit procedures as any other account in the FEU's financial statements. The FEU 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. [378] Ms. Roy and Mr. Thomson elaborated on why the proposed methodology is more transparent than it would be in the deferred charges schedule.[379]

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[374] Thomson: T4, p. 540, l. 10 to p. 541, l. 2. Roy: T3, p. 344, ll. 5-11: "…the main focus of our recommended approach is to allocate the costs appropriately to the different customers that are using those assets."

[375] Exhibit B-9, BCUC IR 1.143.1.

[376] Exhibit B-1, pp. 287-288 and Appendix E-2, p. 9.

[377] Exhibit B-9, BCUC IR 1.151.15.

[378] Exhibit B-9, BCUC IR 1.147.1.

[379] Roy and Thomson: T4, p. 530 l. 5 to p. 532, l. 25.

222. The transparency also provides a practical benefit of facilitating reporting obligations under IFRS and US GAAP.[380]

223. Mr. Kennedy provided his expert view that the broad acceptance of the proposed methodology is attributable, in part, to the transparency of the methodology:

> MR. KENNEDY: A: One other point I think that's worth making is, this treatment that FortisBC is making in this application is completely consistent with the treatment of many regulated utilities throughout the country. I think it's totally consistent across the Fortis group of companies across the country. It's consistent with the manner in which the Alberta Board in Alberta Regulation required the utility to make disclosure. It's consistent with the understanding I have with the Ontario Energy Board required disclosure with regard to net negative salvage.
>
> As I go across the country, it's consistent with what I've seen in at least two of the Maritime provinces, consistent with what I've seen in Quebec. So it's a very consistent manner, and I think it's consistent in part because of the transparency. And secondly, it provides a very easy manner in which, as utilities have looked at the IFRS question and how you manage the different treatment for IFRS for GAAP purposes, to regulatory, it provided a very easy mechanism to find that liability account.[381]

Benefit #3: Promotes Rate Stability

224. A further attribute of the proposed approach is that it promotes rate stability over time.[382] Mr. Kennedy explained that, by contrast, the "pay as you go" approach leads, over time, to a "very lumpy and unstable toll". [383] The asset age curve included in the evidence, which shows the retirements peaking in the next several years, drives home the fundamental shortcoming of the "pay as you go" approach. Mr. Kennedy concluded that, given the age of the utility plant and the delivery rate pressures, "the most long-used and most stable…likely is

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[380] Roy and Kennedy: T4, p. 533, ll. 15 to 20.

[381] Kennedy: T4, p. 532, l. 26 to p. 533, l.20.

[382] Roy and Thomson: T5, p. 709, l. 12 to p. 711, l. 7. Thomson: T4, p. 540, l. 10 to p. 541, l. 2. Ms. Roy and Mr. Thomson elaborated on the reason why the proposed approach smoothing effect on rates in response to questions from Commissioner MacMurchy.

[383] Kennedy: T3, p. 461, l. 23 to p. 463, l. 13. Mr. Thomson elaborated on how the experience compares to that of the FortisBC electric utility at T5, p. 697, l. 3 to p. 698, l. 18.

the approach to be followed here, using the average group life or average service life approach and using the traditional net salvage approach."[384]

Benefit #4 Administrative Efficiency

225. The traditional approach minimizes administrative costs related to implementation, maintenance, and tracking of negative salvage costs.[385] The "pay as you go" approach is also easy to explain and administer, although using that methodology will likely require deferral accounts to capture forecast vs. actual differences in removal costs.[386]

(b) Addressing Forecast Uncertainty and Availability of Funds

226. The FEU's evidence, and the evidence of Mr. Kennedy, regarding the relative benefits of the traditional approach identified above, was largely unchallenged. Commission Staff focused on two issues with respect to the traditional approach: (1) the accuracy of estimating and (2) the availability of funds. These issues are discussed in detail below in relation to the "pay as you go" approach (which avoids the need for long-term estimating) and the ARO approach with segregation of funds. The FEU submit that the issues raised by Commission Staff are largely mitigated in the traditional approach, and benefits of the traditional approach are significant. The Commission should accept the evidence of the FEU and Mr. Kennedy as to why the traditional approach is the best alternative for the Companies and customers.

"Pay as You Go" and Forecast Uncertainty

227. The main attribute of the "pay as you go" approach emphasized by Commission counsel in his cross-examination of the Finance Panel was the fact that only short-term estimates are involved. However, the FEU have adopted a reasonable estimating process under

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[384] Kennedy: T3, p. 461, l. 23 to p. 463, l. 13. Mr. Thomson elaborated on how the experience compares to that of the FortisBC electric utility at T5, p. 697, l.3 to p. 698, l. 18.

[385] Roy: T3, p.343, ll. 14-24.

[386] Exhibit B-1, Appendix K-2, p. 10.

the traditional approach. Variances will occur but customers and the shareholder are kept whole over time.[387]

228. The traditional methodology addresses accuracy of negative salvage forecasts for assets subject to group depreciation methodologies through regular, periodic reviews and updating of negative salvage rates in conjunction with the updating of the depreciation rates (every 3 to 5 years). Ms. Roy stated: "And no estimating process is going to be a perfect one, but through the process of periodically reviewing the depreciation and negative salvage estimates, that is the process that works the best to come up with a reasonable estimate over time."[388] As part of the updating process, annual estimates are compared against updated actual removal costs incurred so that any changes can be factored into future estimates.[389] 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.

229. In the event that the FEU spends less on retiring assets in a given year than is collected in net negative salvage under the traditional method, customers are still no worse off. Ms. Roy explained that under the traditional approach the amounts collected are credited to rate base, such that the rate base is reduced. Removal costs are debited to rate base as incurred. The net difference remains as a credit to rate base, and customers are not paying a return on that amount.[390] It would be tracked separately by asset class.[391] Ms. Roy walked through detailed examples of how the proposed methodology works, and how customers are kept whole over time.[392]

230. Commission Staff questioned whether the shareholder should bear any risk for variances in estimates under the traditional method. The fact that these removal costs occur in the future and therefore have to be estimated under the traditional approach does not change

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[387] Exhibit B-9, BCUC IR 1.143.1.
[388] Roy: T4, p. 556, ll. 8-25.
[389] Exhibit B-9, BCUC IR 1.137.6.
[390] Roy: T4, p. 528, ll. 15 to 24; T4, p. 531, l. 22 to p. 532, l. 4.
[391] Roy: T3, p. 344, l. 23 to p. 345, l. 12.
[392] Roy: T4, p. 523, l. 8 to p. 526, l. 16.

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.[393]

231. In summary, the FEU acknowledge that the estimates required to determine the future removal costs are, by their nature, uncertain. 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 the FEU have proposed. Under the proposed method, the shareholder does not recover any windfall gains and customers are only paying for the prudently incurred cost of decommissioning assets.[394]

The ARO Approach and Segregation of Funds

232. The third option considered by the FEU in its Asset Retirement Obligation Report was an ARO approach, which would mirror the calculation of an ARO under GAAP. Under this method, asset removal costs for each asset class would be estimated going out for the remaining asset class life by year, and then these removal costs would be discounted to today’s dollars. These estimated amounts would then be added to the asset and an equal and offsetting ARO liability would be created. Each year, the asset would be depreciated and the liability would be accreted so that at the time the asset is removed the asset is fully depreciated and the liability fully funds the removal costs incurred.[395] While this approach collects removal costs from customers that benefit from the assets and is familiar to accountants, it suffers many disadvantages that make it less desirable than the traditional approach for broader application.[396] Given the disadvantages, the FEU have proposed to use the ARO approach if any AROs are required to be recorded under GAAP, but not for ongoing removal costs.

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[393] Exhibit B-9, BCUC IR 1.137.8.

[394] Exhibit B-9, BCUC IR 1.137.6.

[395] Exhibit B-1, Appendix K-2, p. 12.

[396] Exhibit B-1, Appendix K-2, p. 12.

233. Commission Staff's interest in this ARO method appeared to centre on the fact that a refinement to the ARO methodology involves segregating funds collected from general utility operating funds.[397] Staff also noted the NEB's requirement for pipelines to maintain the funds in a segregated trust. However, the rationale employed by the National Energy Board for requiring pipeline companies to hold net negative salvage in trust is not applicable in the case of established distribution utilities like the FEU. Mr. Kennedy explained that large diameter pipelines are supply or market constrained and have end of life built into the systems. Distribution companies, by contrast, do not have a terminal life estimate built in to depreciation rates, and it is not expected that the whole system will reach end of life at one time.[398] 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.[399]

234. FEU outlined five reasons why it was beneficial to hold funds collected from customers as net negative salvage within the utility, rather than segregating them in a trust or otherwise. Those reasons were:[400]

- First, the NEB approach would contemplate Commission approval to access funds. This would not be reasonable for the everyday removal costs incurred by the FEU. The ensuing process would not be administratively efficient for the relatively small dollar values involved.
- Second, the trust scenario would result in a number of administrative costs including: the set up and ongoing maintenance of the trust arrangement; tracking systems to segregate funds by asset class; and the determination of the investment strategy of the fund and who should bear the risk/reward of account performance.[401]

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[397] Exhibit B-9, BCUC IR 1.147.1. "A further refinement of the ARO methodology is to segregate funds for future assets removals in a separate independent fund, similar to what is proposed by the NEB for pipelines."

[398] Kennedy: T4, p. 543, l. 25 to p. 545, l. 24.

[399] Exhibit B-9, BCUC IR 1.143.1.

[400] Exhibit B-9, BCUC IR 1.147.1.

[401] Exhibit B-1, Appendix K-2, p. 12.

- Third, the tax issues associated with the creation of a trust are extremely complex and would require significant legal and tax expertise to resolve. Issues include: whether the utility would be able to deduct contributions on behalf of customers; whether the trust would be able to deduct payment to the utility; who would pay the tax on the investment income in the trust; and whether losses could be trapped in the trust. Overall the tax issues are extremely complex and the FEU believe they would be very costly and complicated to resolve with no certainty at this point as to the outcome.

- Fourth, the customer rate impacts of a trust scenario are uncertain due to the uncertainty around the deductibility of the removal costs

- Fifth, Mr. Thomson explained that the cost to customers of segregating funds is significant: [402]

> Our return on rate base requirement, the debt and equity funding that supports our rate base, I believe it's 7.78 percent effective on the total rate base amount, if we were to segregate these funds and put them in a trust account, we might earn 2 percent, 3 percent. It wouldn't have the impact of adjusting our rate, putting a credit to rate base. So the net cost to customers would be 5 or 6 percent higher on the overall balance in those segregated funds account. So because it's a source of funding to the utility, we can use it and we don't have to incur those costs elsewhere. So there is a great benefit to customers for treating it this way, and that's how we treat the OPEB, other post employment benefits deferral account that Mr. Fulton referred to earlier, same way we propose to treat this.

235. In summary, the FEU submit that an ARO segregated fund approach would result in increased costs to ratepayers with no real added value and therefore should not be adopted by the Commission.

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[402] Thomson: T4, p. 542, l. 12 to p. 543, l. 10.

(c) Conclusion Regarding Method of Recovering Net Negative Salvage

236. The traditional approach for recovering removal costs that has been proposed by the FEU is consistent with the BCUC Uniform System of Accounts, GAAP and is the generally accepted regulatory treatment across North America.[403] It distributes costs to ratepayers equitably over time, and improves utility accountability. 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.[404] The FEU therefore submit that the FEU's proposal to return to using the traditional approach should be accepted.

D. "ASSET LOSSES"/ UNRECOVERED DEPRECIATION FROM PRIOR TO 2010

237. The depreciation rates included in Mr. Kennedy's Depreciation Study include a provision for recovery of unrecognized loss balances (i.e. unrecovered depreciation) that accumulated prior to 2010.[405] The FEU responded to many Commission Staff information requests on the subject of "asset losses", and Commission counsel pursued this issue at length during the oral hearing. The overall thrust of these questions was to suggest that the asset losses should be excluded from rate base. As discussed below, including a provision for recovery of asset losses in depreciation rates is consistent with past practice[406], the BCUC Uniform System of Accounts, previous BCUC decisions, GAAP, and the regulatory treatment applied to other utilities across Canada and North America. Sound principle underlies the broad consensus requiring recovery. The asset losses relate to prudently obtained assets that are being fully consumed in utility service, and the losses are the expected byproduct of the group depreciation methodology employed.[407]

238. In the subsections below, the FEU will:

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[403] Kennedy: T4, p. 532, l. 26 to p. 533, l. 20; Roy: T3, p. 423, ll. 18 to 25; Exhibit B-1, Appendix E-2; Exhibit B-9, BCUC IR 1.143.8.

[404] Exhibit B-9, BCUC IR 1.143.1.

[405] Exhibit B-17, BCUC IR 2.44.2; Roy: T4, p. 584, ll. 12-25.

[406] The 2010-2011 NSA, in which it was agreed that net unrecovered depreciation would be recorded in a deferral account, represented a departure from past practice.

[407] As demonstrated in the report included in Appendix E-3.

- Outline the magnitude of the asset losses at issue; and
- Discuss the reasons why it is appropriate for FEU to recover asset losses that accumulated prior to 2010.

(a) Amount of Unrecovered Depreciation From Previous Years

239. FEI's total accumulated asset loss is $149 million. Four specific asset classes contributed to over 90 percent, or $138 million, of that amount. The assets classes are: 474 Regulators and Meter Installations, 478 Meters, 473 Services and 475 Mains.[408] Included in the $138 million is $54 million of actual removal costs incurred, leaving $84 million of actual losses for those asset classes.

240. For FEVI, over 92 percent of the accumulated loss balance of $39 million relates to "disaggregation entries" that resulted from an accounting system adjustment made on the purchase of Vancouver Island in 2003. Excluding these disaggregation entries and incurred removal costs of approximately $1.4 million, the accumulated loss balance at the end of 2009 would be in the order of $1.6 million.[409]

(b) Rationale for Recovering Past Asset Losses in Depreciation Rates

241. Below, the FEU explain why asset losses are recoverable in the proposed depreciation rates. The starting point in the analysis is to understand that the existence of asset losses, or unrecovered depreciation, is an expected outcome of the group depreciation methodology. The group depreciation methodology is recognized in the Commission's Uniform System of Accounts, has been expressly approved in prior Commission decisions, is acceptable under GAAP, and is routinely employed in the regulation of public utilities. The FEU submit that, based on the evidence and Commission precedent, it is appropriate for the proposed depreciation rates to include a provision to recover past asset losses.

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[408] The analysis of the accumulated losses provided in Appendix E-3 focuses on these four asset classes.

[409] Exhibit B-1, pp. 290-291.

Unrecovered Depreciation is a Product of Group Depreciation Methodology

242. The “asset losses” are the portion of the original cost of assets that was incurred to put those assets into service which has not yet been recovered through depreciation expense.[410] The existence of asset losses, or unrecovered depreciation, is a product of group depreciation methodologies that are routinely employed in the regulation of public utilities.

243. Mr. Kennedy, whose expertise includes group depreciation and the regulatory treatment of accumulated losses,[411] explained the difference between group depreciation employed by the FEU and other utilities and standard depreciation practices in the following way:

> In the world of public utility regulation, the companies are very acid [sic - asset] intensive and have very particular means in which they record those assets. It's not uncommon for a utility to have literally millions of similar assets. Since about the turn of the twentieth century, however, since about the early 1900s, the role of regulated companies have followed some rather unique if not slightly different accounting practices known as group depreciation and group accounting practices. And that was simply to deal with the large number of similar assets. For example, expect a utility to track and depreciate every single power pole, for example, would be a voluminous and at that time virtually impossible.
>
> So there's been a number of accounting practices and procedures that have been widely accepted as being the norm for utilities. So that is quite different than would be traditional accounting, if you will.
>
> To deal with the manner in which utilities have -- regulated utilities have dealt with the accumulation and the structuring of assets, there has become a large number -- or a number of rather unique depreciation practices to deal with that group of utilities. It would not be normal to expect, for example, all of the telephone poles or power poles or miles of pipe that are installed this year, to all have an exact life and all retire at the same time. So the regulated utility industry have really followed the practice of the life insurance industry and gone to an actuarial type of mortality, a retirement dispersion analysis in the development

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[410] Roy: T4: 571, ll.2-12.

[411] Kennedy: T2, p. 282, l. 18 to p. 283, l. 2, where Mr. Kennedy describes how the adequacy of accumulated deprecation and the level of accumulated losses is considered in “virtually every depreciation study” that he undertakes and “is standard practice of analyzing the capital recovery schedule of utilities”.

> of depreciation schedules. So that's what I mean by the unique practices for public utility, plant accounting and public utility depreciation practices.[412]

244. Under the group accounting method that the FEU follow, it is expected that some assets within an asset group will be removed from service prior to the expected life of the asset group, and some assets within the group will be removed from service after the expected life of the asset group. "Asset losses" are the result of inadequate recovery of depreciation from customers for assets within a group that have been removed from service due to customer request or for operational and/or safety reasons. It does not indicate that the particular asset was retired (or taken out of service) before the end of its economic useful life, but only that the historically approved group depreciation rates were not adequate to recover the cost of the asset over the period of time that it was in service.[413] Thus, asset losses are more accurately characterized as unrecovered depreciation.[414]

245. We should expect the FEU to record some under-recovered depreciation in the years prior to the average service life of the asset group.[415] 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. 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.[416] Mr. Kennedy and Ms. Roy's evidence on this point was clear, and included the following passages:

> MR. KENNEDY: But to the extent that a retirement occurs prior to the average age of its expected life – in other words, if we pick a 50- or a 60-year life for a transmission pipe and then anything that retires prior to the 60th year is going to cause an inherent loss on retirement. We expect it. That is something that's built in in the philosophy of group life depreciation. Where anything that retires from age zero through the average age, in the case of that pipe, 60 years as we've

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412 Kennedy: T2, p. 275, l. 26 to p. 277, l. 8.

413 Exhibit B-9, BCUC IR 1.117.3; Thomson: T3, p. 430, ll. 10-12.

414 Exhibit B-9, BCUC IR 1.148.4.

415 Exhibit B-9, BCUC IR 1.155.6 and Exhibit B-17, BCUC IR 2.74.13. Exhibit B-9, BCUC IR 1.148.4.

416 Exhibit B-9, BCUC IR 1.148.4.

previously had it, 65 years as we have it now, is going to cause an asset loss. And so that account will build up on a very expected basis. Anything that lasts longer than that 65 years will result in a gain and in essence recover that loss. So, I think to answer your question very directly, sir, is that what we're seeing is an expected phenomenon, seeing something that's common throughout the industry where we are building up losses because we haven't got quite to that 60th year. We're getting close, and we're retiring assets on a very proactive and, I think, needed basis.[417]

….

MS. ROY: A: … But the average service life methodology by design will result in asset losses that will occur when we're in the first half of that average service life curve of the assets. So some part is expected. Then there is some other part of the asset losses that would have resulted from changes in technology and operating requirements, and the only way to start to draw down those part of the asset losses is by changing depreciation rates. So, and a change in depreciation rates would have ameliorated the size of the asset losses. I wouldn't go so far -- and we've described in an IR response, it wouldn't have taken away the asset losses because some of them are there by design.[418]

….

MR. KENNEDY: A: When we set an average service life, it is by nature an average. So if we put in ten services in a given year, one would expect because of various forces of retirement, some of those services to come out in year one and some in year two and some in year three, et cetera, et cetera, and all the way to perhaps year ten. The average of all those expected ages would be five, so we'd set a depreciation rate of 20 percent.

Well, that doesn't mean that we didn't expect some to come out at year one, and in fact we estimated some to come out in year one when we set that average age of five years. But the one that comes out at age one has only had one year of depreciation applied to it, so it's only 20 percent depreciated. It's appearing to have an 80 percent loss, but it's not. That was part of that averaging that we dealt with when we built that five-year average life for some of those services.

So there's a function -- two things, as Ms. Roy explained. There is the change of estimates. Maybe next time we would estimate those services to have a life of six years, not five years. But there's also the realization that some assets, as

[417] Kennedy: T3, p. 339, l. 15 to p. 340, l. 9.

[418] Roy: T3, p. 431, ll. 6-23.

> expected, do retire earlier than that age five, age one, two or three, that causes what appears to be a loss on retirement, really when it is more like it's simply an expected early retirement, a retirement earlier than the average service life.[419]

246. The FEU's Asset Loss Report documents the reasons for the accumulated unrecovered losses by asset category.[420] 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. In essence, however, the asset classes that have led to the build up in unrecovered depreciation have an average life of approximately 40-50 years and have not yet reached their average life expectancy. Thus, these retirements tend to give rise to asset losses merely by operation of group depreciation.[421]

247. For illustrative purposes, the FEU provided a graph showing the estimated annual and cumulative gains and losses for distribution mains through the year 2128. As indicated in the graph, losses are expected to continue until approximately year 2060 at which time, based on the modeled assumptions and average estimated life, retirements of distribution mains are expected to lead to gains:[422]

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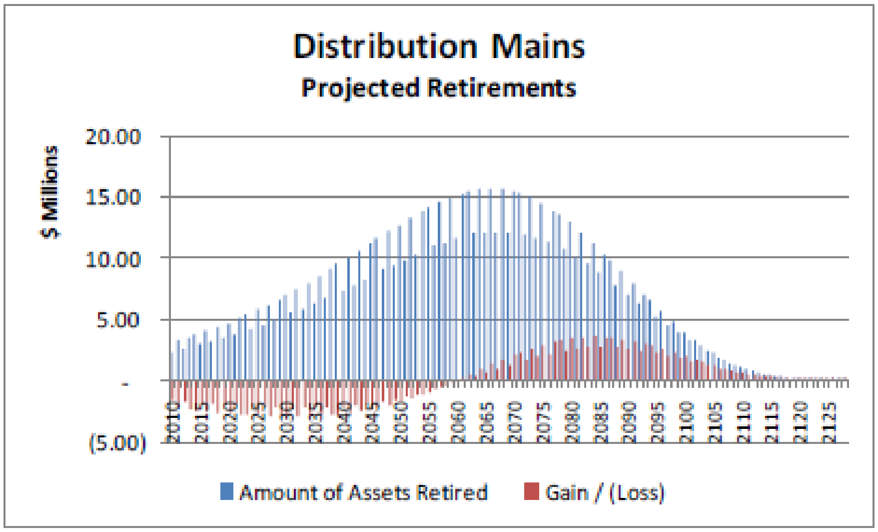
[419] Kennedy: T3, p. 432, l. 2 to p. 433, l. 5.

[420] Exhibit B-1, Appendix E-3.

[421] Exhibit B-9, BCUC IR 1.148.4.

[422] Exhibit B-17, BCUC IR 2.74.13.



248. Over the asset life profile, the retirement losses and gains are expected to net out to zero.

249. Thus, the existence of asset losses is inherent in the group depreciation methodology, and the amount of the asset losses at the current time is to be expected based on when the bulk of FEU's long-lived system assets were installed. The FEU submit that it would be perverse for the Commission to now conclude that the FEU could not recover asset losses that were a direct result of Commission-approved depreciation methodologies.

Group Depreciation Specified in Uniform System of Accounts and Acceptable Under GAAP

250. The group depreciation method is contemplated in the Commission's Uniform System of Accounts and in GAAP.

251. Under the Commission's Uniform System of Accounts, quoted below, the FEU are required to capitalize un-depreciated amounts on asset removals to accumulated depreciation:[423]

> When a plant unit is retired from gas operations the ledger value thereof shall be eliminated by crediting the appropriate plant accounts. …If the plant being retired is classified as depreciable, the ledger value less the net salvage value

[423] Exhibit B-17, BCUC IR 2.74.2.

and/or insurance, if any, recovered shall be charged to accumulated depreciation.

….

Ledger value is the amount at which property is carried in the plant account. In case the value of any portion of plant is not shown separately, the ledger value of that portion shall be its proportionate share of the value of the entire group in which the particular plant is included.

….

The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group.

….

When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization. Assets remaining in use after reaching the average life expectancy are not regarded as fully depreciated until actual retirement.

252. The above passages from the Uniform System of Accounts expressly recognize that the group depreciation method is based on the average life of the class and not the actual life of individual assets within the class. Although the Commission-approved accounting policies classify these items as "losses," the Uniform System of Accounts, in effect, deems there to be no loss when an individual asset is retired or disposed of under circumstances reasonably provided for through accumulated depreciation, stating: "whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of

retirement under such circumstances, is equal to the cost". In any case, the classification as a "loss" does not change the amount of the rate base inclusion for these items.[424]

253. The group accounting method that results in assets continuing to be depreciated after they have been removed from service is acceptable under generally accepted accounting principles (US GAAP).[425] PriceWaterhouseCoopers LLP prepared a report entitled "Accounting for Property, Plant and Equipment, Asset Retirement Obligations and Depreciation."[426] The report states:

> The composite convention of accounting is an acceptable convention regardless of whether an entity is subject to cost-of-service regulation. As noted above, the composite or group convention was established as a means of simplifying the process of tracking a large asset system with many small components with small relative values compared to the larger composite group. As discussed in the following excerpts from Chapter 11 of Kieso, Weygandt, and Warfield's Intermediate Accounting Text (11th Edition), both of these conventions of accounting are considered acceptable conventions pursuant to GAAP.

254. The report goes on to recommend that "businesses using the composite or group deprecation convention should regularly obtain updated depreciation studies (perhaps every 3 – 5 years), which is consistent with FERC regulations."[427] This is in complete alignment with Mr. Kennedy's recommendations and the FEU's position.

255. The FEU have followed the Commission's Uniform System of Accounts and GAAP and all deprecation rates have been approved by the Commission.

Recovery Consistent with Accepted Regulatory Practice and the Regulatory Compact

256. Mr. Kennedy observed: "It's widely accepted that the variances between the required amount of accumulated depreciation and the actual booked amount of depreciation become trued up in future periods." He cited the practice in "all Canadian jurisdictions and

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[424] Exhibit B-9, BCUC IR 1.148.4.

[425] Exhibit B-17, BCUC IR 2.74.2.

[426] Exhibit B-17, Attachment 74.2.

[427] Exhibit B-17, BCUC IR 2.74.2.

most North American jurisdictions."[428] The FEU submit that the reason the Uniform System of Accounts, industry practice and GAAP all support the recovery of asset losses is because the costs of the assets are prudently incurred and used for utility service and therefore recoverable from customers in rates. As Mr. Thomson put it: "…the full life of the asset has been applied to utility service."[429] There is no suggestion that the installation of system assets that gave rise to the asset losses (many of which were installed decades ago), or the requirement to pull those assets from service, was imprudent. 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.[430] Allowing recovery of prudently incurred costs of assets used for utility service by including a provision to recover asset losses in depreciation rates is fundamental to the right of the shareholder to an opportunity to earn its allowed return of capital.

Retired Assets Within the Class Are "Used and Useful" Until Class is Retired

257. Commission Staff's primary basis for questioning the recoverability of unrecovered depreciation related to prudently acquired assets appears to be the potential that the "asset losses" included in rate base may relate to individual assets that are no longer in use. However, the group depreciation methodology is premised on full recovery of capital invested *in the class* during the life *of the class*, irrespective of when the individual assets in the class are retired.

258. The Commission has previously recognized that the effect of the treatment specified under the Uniform System of Accounts is that customers will continue to pay for unrecovered capital through depreciation charges even though the asset is no longer in service. The Commission's Decision in *West Kootenay Power Ltd., Application to Sell its Hydroelectric Generation Assets,* dated October 26, 2001, states (at page 10):

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[428] Kennedy: T4, p. 573, ll. 2-9.
[429] Thomson: T4, p. 571, ll. 7-12.
[430] Exhibit B-9, BCUC IR 1.148.4.

> The Commission requires all public utilities under its jurisdiction to adopt a Uniform System of Accounts. The system is designed to set out the facts in connection with the financing, construction and operation of an electric utility on a basis which will be readily comparable with other electric utilities in Canada and the United States. The accounts are used to record the income and expenses to enable interested parties to see whether the utility has recovered its approved return on equity at the end of its operating year. The accounts are also designed to determine the appropriate treatment of income and expenditures with respect to utility rate applications.
>
> The plant accounts are used to record the original cost of assets purchased by the utility. When those assets are placed in service they become part of the rate base, upon which the utility is entitled to receive a return and to recover the capital it has invested in the form of depreciation charges over the useful life of the asset. When an asset is retired from service, the Uniform System of Accounts specifies that the ledger value less the net salvage value shall be charged to accumulated depreciation, so that customers continue to pay for any unrecovered capital through future depreciation charges, even though the asset is no longer in service. [Emphasis added.]

259. BC Hydro also recovers depreciation on assets after they have been retired based on the group depreciation methodology.[431]

260. Group accounting remains consistent with the obligation to provide utilities with the opportunity to obtain the return of invested capital by, in effect, presuming that the assets *within the class* are "used and useful" until the point at which *the entire class* is retired. Excluding particular assets within the class from rate base before the class is fully depreciated on the basis that the particular asset is no longer in service makes it impossible for the shareholder to fully recover the capital prudently invested in the class of assets used for utility service.[432] This is contrary to the regulatory compact.

Asset Losses Occur in the Ordinary Course of Business

261. The "asset losses" at issue in this proceeding are fundamentally different in nature from the gains and losses on the sale of assets outside the ordinary course of business pursuant to section 52. Extraordinary retirements generate losses where the assets are sold to

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[431] Exhibit B-17, BCUC IR 2.74.10.

[432] Roy: T5, p. 701, l. 14 to p. 702, l. 17; Roy: T4, p. 571, ll. 2-12.

a third party before the end of their useful life for a value that is less than their carrying value.[433] In the case of the asset losses at issue here, the entire asset giving rise to the asset loss was consumed in performing utility service and is not being sold. The response to BCUC IR 1.136.2 lists the dispositions of property outside of the ordinary course of business in the last 10 years. Other than these transactions, all other dispositions of property have been in the ordinary course.[434] Section 52 of the UCA is therefore not engaged with respect to unrecovered depreciation, and the analogy to gains and losses on extraordinary retirements is inapplicable.

(c) FEU's Responsibility for Accumulated Asset Losses

262. There were a number of questions directed at whether the FEU bears responsibility for having contributed to the accumulation of asset losses as a result of either failing to detect growing loss balances or employing depreciation rates that were too low. These suggestions are considered below, but the FEU submit that these issues affect the timing of recovery only. They do not alter the fundamental obligation to enable the FEU to recover the full investment in the class over the life of the class.

Detecting Loss Balances

263. The FEU have investigated and described the reasons for the accumulated losses in its Asset Loss Report and have responded to numerous information requests regarding the losses.[435] As discussed above, under the group depreciation method the FEU expected that the balance of unrecovered depreciation in the classes of assets at issue would continue to grow for some time. The need for further detailed investigation of the balance was not apparent until during the recent 2010-2011 RRA proceeding.[436]

264. During the period when losses were accumulating, there was a Commission-approved process and methodology in place for ultimate recovery of the unrecovered

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[433] Exhibit B-9, BCUC IR 1.117.3; Thomson: T3, p. 430, ll. 10-12.

[434] Roy and Kennedy: T4, p. 587, l. 2 to 590, l. 5.

[435] Exhibit B-1, Appendix E-3; Exhibit B-9, BCUC IR 1.1481 to 1.153.3.

[436] Exhibit B-9, BCUC IR 1.148.1; Exhibit B-17, BCUC IR 2.73.1.

depreciation and the FEU were following that treatment. As such, the FEU expected that the loss balance would continue to grow until such time as depreciation rates could be implemented that would begin to recover these balances over the remaining lives of the associated assets, and then the balances would slowly begin to reverse. While, there was no opportunity to increase depreciation rates during the PBR period, the FEU proposed new depreciation rates in the first revenue requirement after PBR in order to begin to address the issue.[437]

265. In the FEU's submission it has acted entirely reasonably. The record is clear that the FEU have at all times followed the Commission-approved treatment for retirement of assets and have come forward with proposals to increase depreciation rates at every opportunity.

Adequacy of Past Depreciation Rates

266. The accumulation of asset losses was accelerated by the fact that the Commission-approved depreciation rates before and during the PBR period were lower than had been recommended by the FEU in successive depreciation studies,[438] a step taken to mitigate short-term rate impacts on customers.[439] 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.[440] No issue arose regarding the sufficiency of depreciation rates in the years prior to the 2010-2011 RRA because the return of capital prudently invested in assets fully consumed in the course of providing utility service had never been in doubt.[441] The FEU had reasonably expected that the Commission would continue to abide by the depreciation methodologies it had adopted and uniformly applied to BC utilities.

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[437] Exhibit B-17, BCUC IR 2.73.1.

[438] Exhibit B-1, 290-291. Exhibit B-17, BCUC IR 2.74.12.The FEU have documented their efforts since the early 2000's to increase depreciations rates and begin to recover accumulated losses over the expected lives of the assets.

[439] Exhibit B-9, BCUC IR 1.148.4.

[440] See Exhibit B-17, BCUC IR 2.74.15.1 for evidence supporting this statement.

[441] Exhibit B-17, BCUC IR 2.73.1.

267. The FEU's proposed depreciation rates in the past would not have recovered all of the accumulated losses. This, however, does not mean that the previously proposed recommended depreciation rates were incorrect. 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.[442] 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, it is expected that less than 20 percent to 25 percent of the losses would be addressed through higher depreciation rates and that the remaining amounts would be recovered over the next 30 to 40 years.[443]

268. 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.[444]

(d) Conclusion on Recovery of Unrecovered Depreciation from Prior to 2010

269. The asset losses that have accumulated from years prior to 2010 are the product of group depreciation methodology. Including unrecovered depreciation in depreciation rates is consistent with past practice, the BCUC Uniform System of Accounts, previous BCUC decisions, GAAP, and the regulatory treatment applied to other utilities across Canada and North America. The asset losses relate to prudently obtained assets that are being fully

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[442] Exhibit B-9, BCUC IR 1.155.6.

[443] Exhibit B-9, BCUC IR 1.155.6.

[444] Exhibit B-9, BCUC IR 1.155.6.

consumed in utility service. The FEU respectfully submit that it would be fundamentally unfair for the Commission to have endorsed the group accounting methodology for use by the FEU and other utilities for many years, only to subsequently rely on the necessary outcome of that methodology as a basis for excluding from rate base unrecovered depreciation on assets properly incurred to provide service to customers. It would be particularly unjust since this assessment is being performed at a time when the bulk of the FEU's system assets subject to group accounting have yet to reach their average life. In such circumstances, by definition, it is not possible for most assets to have reached the point of full recovery, let alone exceed the average life to reflect a gain.

270. The FEU respectfully request a clear determination in favour of the FEU on this matter, as lingering uncertainty over the recoverability of these prudently incurred costs introduces a significant regulatory-related business risk. That is not in the interest of customers or the shareholder.

E. PROPOSAL FOR RECOVERY OF UNRECOVERED DEPRECIATION FOR 2010 AND BEYOND

271. Net losses realized subsequent to 2009 have been recorded in a deferral account instead of in accumulated depreciation, as agreed to in the 2010-2011 NSA for FEI and FEVI. The FEU propose to maintain this treatment for 2012 and 2013, and in addition have proposed a 20 year amortization period for the deferral account that is aligned with the average service life of the asset categories that are contributing to the losses. The proposed treatment will achieve the same result for ratepayers in respect of the 2010-2013 accumulated losses as the historical treatment followed by the FEU.[445] The practice of recording the gains and losses in a deferral account with recovery over 20 years is also consistent with the group system of accounting and the Uniform System of Accounts and provides the benefit of an increased level of transparency into the trends in asset removals being experienced by the utilities.[446]

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[445] Exhibit B-1, pp. and 408-409. Roy: T4, p. 574, l. 16 to p. 575, l. 12.

[446] Exhibit B-17, BCUC IR 2.74.2. Roy: T4, p. 574, l. 16 to p. 575, l. 12

272. Commission Staff prepared a Witness Aid using an example of a truck to demonstrate a scenario where, under the proposed methodology, the shareholder might over-recover depreciation. Ms. Roy did not accept that the Staff Witness Aid was a fair depiction of how the proposed methodology works; Mr. Kennedy concurred. In response:

- Ms. Roy indicated that she considered it to be unfair because it "is the worst possible scenario that could be constructed to show the worst outcome for the utility".[447] Mr. Kennedy explained how the "perfect storm of bad kind of results with the company" are very unlikely to materialize in practice. [448] The simplified example also excluded some key mitigating factors that would be likely even in that "perfect storm" situation. [449]

- Mr. Kennedy observed that the example was also unrealistic because a different accounting methodology –amortization accounting treatment - would be used for short life assets of that nature that would ensure there is no gain or loss.[450]

- Mr. Kennedy observed that the example was also unrealistic because it approached the depreciation issue from the perspective of a single asset, rather than acknowledging the implications of group depreciation.

273. Ms. Roy clarified that the "overpayment" evident in the example is a product of the witness aid using a simplified example of a single asset, rather than a class of assets: "This is a single asset example. We do not work in a single asset world. We work in a group accounting world."[451] Mr. Kennedy and Ms. Roy confirmed that, unlike what occurs in the single-asset example, where the regulated asset classes are concerned the funds collected are returned to the customer.[452] On this point, Ms. Roy and Mr. Kennedy stated:[453]

> MR. FULTON: Q: But just sticking with the simplified example for a moment, that $20 never goes back to the ratepayers, does it?

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[447] Roy: T4, p. 566, l. 16 to 568, l. 22.

[448] Kennedy: T4, p. 569, ll. 1-16.

[449] Kennedy: T4, p. 569, ll. 1-16.

[450] Kennedy and Roy: T4, p. 569, l. 17 to p. 570, l. 7.

[451] Roy: T4, p. 529, ll. 4-10.

[452] Roy and Kennedy: T4, p. 528, l. 15 to p. 530, l. 4. In any event, the majority those assets that are tracked at an individual service life level do not attract negative salvage. In the exceptional case where an individual asset does attract negative salvage, the estimates of removal costs would be increasingly accurate as that date of decommissioning nears which would result in minimal over- or under-collection. Exhibit B-9, BCUC IR 1.137.6.

[453] Roy and Kennedy: T4, p. 529, l. 11 to p. 530, l. 4.

> MS. ROY: A: In this simplified example where you had one asset, that would mean the end of the asset class, to provide a comparable example of what we are talking about. That would mean the entire asset class is now removed from service. And if you had a liability when that entire asset class was removed from service, I would suggest you would return it to the ratepayers.
>
> MR. KENNEDY: A: I guess -- I'm going to make one comment, and that's part of the problem of using a single asset example is you don't see the benefit or you don't see the eventual disposition of that $20 of over collection. I think the note here actually captures that a bit, that says that $20 will be used and in fact will be considered in future depreciation studies as part of the future requirement for net salvage on a go-forward basis as we retire the next asset that becomes retired.

Ms. Roy and Mr. Kennedy's disagreement with the simplified example in the Staff Witness Aid underscores the importance of addressing issues relating to depreciation and net negative salvage from the perspective of a regulated business, and not through the lens of non-regulated businesses.

274. Ms. Roy's restated Witness Aid demonstrated how, under group depreciation, under-recovery on one asset within the class would be offset by over-recovery by other assets within the class such that the correct amount of depreciation is recovered over the life of the group. Ms. Roy put it this way: "…that is the benefit of the group depreciation method. Some assets costs more, some assets cost less. Some are retired earlier or later, or put into service earlier, later, but on the whole the idea is that things balance out, so that in the end there is no material variances to depreciation expense."[454]

275. Commission Staff then asked the FEU to produce a second example consistent with Staff's original "perfect storm" assumptions, except with two trucks. This scenario simply multiplied by a factor of two the results of the original (and in the witnesses view, unfair) "perfect storm" scenario. In the undertaking that provided the requested example, the FEU summarized five reasons why this example is unrealistic and would not occur under the FEU's proposed approach.[455]

[454] Roy: T5, p. 657, ll. 9-16.
[455] Exhibit B-47.

276. Staff's challenge to the proposed methodology is only of practical significance if a viable alternative exists. The only alternative discussed in this proceeding, the equal life group methodology, would result in an increase in depreciation expense of approximately $15 million.[456] The FEU respectfully submit that the proposed approach is an appropriate means of recovering unrecovered depreciation.

F. CONCLUSION REGARDING ASSET LOSSES / UNRECOVERED DEPRECIATION

277. For the reasons set out in the sections above, the FEU submit that there is no evidentiary basis or principled reason on which the Commission could find that unrecovered depreciation is not properly recoverable from ratepayers. The FEU's proposal for recovery of unrecovered depreciation going forward is reasonable and supported by the record in this proceeding. The FEU submit that the proposed treatment is just and reasonable and should be approved by the Commission.

[456] Exhibit B-17, BCUC IR 2.74.5.

PART SEVEN: COST OF SERVICE: OTHER FACTORS

278. The FEU's cost of service is also composed of other revenue, taxes, and financing costs and return on equity and is reduced by the Thermal Energy Services Allocation. Each of these are areas are discussed below.

A. OTHER REVENUE

279. Other revenue is an offset to the revenue requirement. For all of the FEU, other revenue includes revenue from service work (connection charges), late payment charges, and returned cheques. In addition, FEI receives revenue for wheeling charges (from Vancouver Island), third party revenue on its SCP, and starting in 2012, revenue from natural gas vehicles service and biomethane recoveries. FEVI also receives revenue from the Mainland for LNG mitigation. In this section we identify the evidence that supports the reasonableness of these forecasts.

(a) Forecast Increases

280. The FEU are forecasting a significant increase in other revenue in 2012 and a further modest increase in 2013.[457] The primary drivers for FEI and FEVI forecasted Other Revenue increases are from CNG/LNG Service and LNG Mitigation Revenues, respectively.[458] Aside from FEVI Wheeling Revenue, SCP Third Party Revenue, and CNG & LNG Service Revenue, the other revenue is miscellaneous ancillary revenue that recovers costs that the utility has incurred. These are incidental to the utilities' operations and not the focus of the primary service of delivering energy to customer premises. The FEU, through the Business Development and other departments, continue to explore service opportunities that can be economically offered that would be beneficial to all stakeholders.[459]

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[457] Exhibit B-1, p. 292, as updated by Exhibit B-1-3.

[458] Exhibit B-8, CEC IR 1.13.1.

[459] Exhibit B-8, CEC IR 1.13.3.

(b) FEI Southern Crossing Pipeline (SCP) Third Party Revenues

281. As explained on pages 295 to 297 of the Application, SCP third party revenues are forecast at approximately $14.8 million for both 2012 and 2013. As described below, the FEU have proposed to change how SCP revenues are allocated to increase transparency and allocate costs based on the principle of cost causation.[460]

282. Historically, the SCP third party revenues have been allocated to customers through the MCRA and the delivery margin. The allocation methodology is intended to reflect the principle that customers paying for SCP in the delivery margin should share in the mitigation revenue associated with the SCP transportation resources. In this Application, the FEU are requesting changes in the allocation of these revenues and related costs to the delivery margin.[461] These changes are as follows.

- Included in the SCP third party revenues are revenue from FEI's firm service contract with Northwest Natural Gas Co. (NWN). FEI provides this firm transportation service to NWN from Yahk to Sumas via SCP capacity and Spectra Energy Kingsvale South Transportation capacity held by FEI. Currently, the revenues from the firm service contract are allocated to the delivery margin. The costs of the holding the Spectra Energy Kingsvale South Transportation capacity, however, reside 100% in the MCRA, even though the capacity is not available for use by the midstream customers to manage core load. The FEU are therefore proposing the allocation of these costs to the delivery margin, where the costs of holding the Spectra Energy Kingsvale South Transportation capacity will be offset by the NWN contract revenues.

- Also included in the SCP third party revenues is mitigation revenue associated with the T-South Enhanced Service. This service is explained in the Application at page 296 and the details on the T-South Enhanced Service Agreement with

[460] Exhibit B-1, pp. 296 to 297 and Exhibit B-9, BCUC IR 1.80.1 and 1.82.3.

[461] Exhibit B-1, pp. 296 to 297 and Exhibit B-9, BCUC IR 1.80.1 and 1.82.3.

Spectra Energy are provided in response to BCUC IR 1.80.2. 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 a result FEI is proposing to allocate all SCP mitigation revenues associated with T-South Enhanced Service to the delivery margin.

283. These changes do not impact SCP revenues,[462] do not impact rates or ratepayers[463] and do not impact third parties.[464] The sole purpose of the change is to more appropriately align costs and revenues in accordance with cost causation principles. The FEU submit that the proposed change in allocation should be accepted.

(c) Mainland – Natural Gas for Transportation Service Revenue

284. Natural Gas for Transportation Service is the compression and dispensing service for CNG fueling and transportation, delivery, fuel storage and dispensing service for LNG fueling. Additional throughput due to Natural Gas for Transportation Service will have a favourable impact on delivery rates, all other things being equal. The original forecasts of costs and revenues for the determination of the 2012 and 2013 revenue requirements had assumed NGV fueling station customer additions and additional throughput. However, this original forecast had been premised on EEC incentive funding for NGVs being available during the test period. The NGV-EEC Decision[465] necessitated the FEU discontinuing EEC incentives for NGV conversions. Offering EEC incentives for NGVs is an important component of the transformation of the NGV marketplace and as noted in the Application, discontinuance of EEC incentives for NGVs represents a significant barrier to achieving additional NGV throughput to

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[462] Exhibit B-1, pp. 295-296.

[463] Exhibit B-9, BCUC IR 1.82.1.

[464] Exhibit B-9, BCUC IR 1.82.2.

[465] Order No. G-145-11.

the system for the benefit of all existing customers. As discussed by Mr. Stout, it has resulted in a delay in the delivery rate benefits to customers.[466]

285. As explained in the FEU's Evidentiary Update filed September 12, 2011,[467] Order G-145-11, which determined that the NGV incentive program is not a demand-side measure within the meaning of the *Clean Energy Act*, resulted in a reduction to other revenue of $2.4 million in 2012 and $4.1 million in 2013, incorporating reductions to both the delivery margin and fueling station recoveries. After this reduction, the FEU are forecasting $1.3 million in each of 2012 and 2013 related to CNG and LNG fueling station revenue and incremental delivery margin revenue.[468]

286. The forecast revenues are from customers that have already received NGV incentives or that are existing Rate Schedule 6 customers.[469] FEI has determined CNG/LNG Service revenues using the minimum "take-or-pay" volume commitment.[470] The CNG and LNG Recoveries deferral account will capture recoveries associated with volume in excess of minimum contract demand and variations from the revenue forecast pertaining to Rate Schedule 16.[471]

287. The Companies have been looking at available means of capturing the benefits from Natural Gas for Transportation Service given the setback presented by the NGV-EEC Decision.[472] However, Mr. Stout stated that all indications are that the revenues from new NGV customers will now be at zero for the test period: "That's kind of the feedback we're getting from the market today, and that's why I said we're looking at other opportunities. So that's – barring some shift by the customers in through [SIC] thought processes and thinking, that's

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[466] Stout: T5, p. 767, l. 10 to p. 769, l. 8.
[467] Exhibit B-21.
[468] Exhibit B-1-3, Updated Application Page 297.
[469] Exhibit B-9, BCUC IR 1.88.1.
[470] Forecast throughput embedded is 169 TJs, Exhibit B-1-3, page 298.
[471] Exhibit B-17, BCUC IR 2.134.1. Exhibit B-1 updated by Exhibit B-1-3, page 399.
[472] Stout and Bennett: T5, p. 768, l. 2 to p. 776, l. 13.

where we feel we're at today."[473] The net impact of the NGV-EEC Decision, including associated depreciation, earned return and income tax implications, is an increase to FEI's revenue requirements for the test period of approximately $2.1 million in 2012 and $3.2 million in 2013.[474]

(d) Conclusion on Other Revenue

288. The FEU's forecasts of other revenue for 2012-2013 reflect all applicable contracts and fixed revenues and are based on the FEU's best knowledge of the factors that drive the variable components. The FEU submit that its forecast of other revenue and proposed change in SCP costs and revenues should be approved.

B. TAXES

289. The tax expenses for 2012-2013 are detailed in section 5.6 of the Application and reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the revenue requirement for each utility. While information requests from Commission staff requested tax-related information,[475] there was no issue raised in the proceeding with respect to the tax forecasts.

C. FINANCING COSTS AND RETURN ON EQUITY

290. The FEU's financing costs and return on equity are explained in section 5.7 of the Application. No issues were raised during the proceeding related to this aspect of the FEU's cost of service.[476]

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[473] Stout: T5, p. 803, l. 25 to p. 804, l. 8.

[474] Exhibit B-21, p. 3.

[475] Exhibit B-9, BCUC IR 1.83.1 to 1.84.1; Exhibit B-17, BCUC IR 2.39.1 and 2.40.1 to 2.40.4.

[476] The only related IR appears to be Exhibit B-8, CEC IR 1.14.1 (Exhibit B-8) in which the FEU explained how it uses short and long-term debt.

D. THERMAL ENERGY SERVICES ALLOCATION: REDUCTION IN NATURAL GAS OVERHEAD

291. The existence of the thermal energy class of service, established pursuant to Commission Order No. G-141-09,[477] necessitates an appropriate allocation of costs to ensure that natural gas rates reflect only the cost of providing natural gas service. In this section, we address the evidence on how costs have been allocated. The FEU have maintained an appropriate division between the classes of service, and reflected in the 2012-2013 revenue requirements the benefit to natural gas customers from shared overhead. The net result is that all costs associated with TES are excluded from the natural gas revenue requirement, and the overhead that must be recovered from natural gas customers is reduced by $500,000 in each of 2012 and 2013. In other words, natural gas customers benefit to the extent of $1 million over the test period as a result of the FEU pursuing TES.

292. The FEU submit that, based on the evidence, the Commission should find that:

- The FEU have employed an appropriate methodology for allocating costs as between the two classes of service during the test period;
- The FEU have an appropriate process in place for time tracking and verification; and
- The amount of overhead allocated in 2012 and 2013, being $500,000 per year, is reasonable.

(a) Conceptual Overview of Classes of Service and How Costs are Segregated

293. FEI's thermal energy services and natural gas services are classes of service within a single integrated public utility. The UCA provides a legal framework for segregating the classes of service for rate setting purposes through allocation of costs and revenues.[478] Pursuant to Order No. G-141-09, all costs associated with TES are captured in a separate deferral account (formerly the "New Energy Solutions Deferral Account", now called the "TES

[477] Approved the 2010-2011 RRA NSA.
[478] Section 60(1)(c).

Deferral Account") for future recovery from TES customers. One of the terms of the NSA was that the balance in the TES Deferral Account would not be recoverable from natural gas customers.[479]

294. This proceeding is concerned with setting natural gas delivery rates.[480] There were a number of questions in this natural gas RRA regarding how costs are tracked within the TES Deferral Account to various projects and recovered from TES customers.[481] While the FEU provided responses to many of those questions, such matters are internal to the TES class of service and do not affect natural gas delivery rates. TES rate design will be considered in FEI's future applications to the Commission to set rates for TES customers. The FEU submit that the Commission should be limiting its Decision in this RRA to matters pertinent to the determination of natural gas rates, which in the case of TES is limited to the proper allocation of costs as between the classes of service.

295. The allocation of costs as between classes of service appeared to be the subject of some confusion in this proceeding. As a starting point, it is important to recognize that FEI is a single utility, and that the exercise is one of the proper allocation of FEI's total costs as between the two classes of service for ratemaking purposes. Conceptually, the process involves three components:

- First, direct costs attributable to the provision of thermal energy service – i.e. those costs associated with 12 FTEs (consisting of 14 employees) - are directly assigned to thermal energy services. These costs were never reflected in this Application as part of the natural gas revenue requirement, and thus do not show up as a cross-charge from the natural gas class of service to TES.

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479 Exhibit B-16, ESAC IR 2.2.1(a)

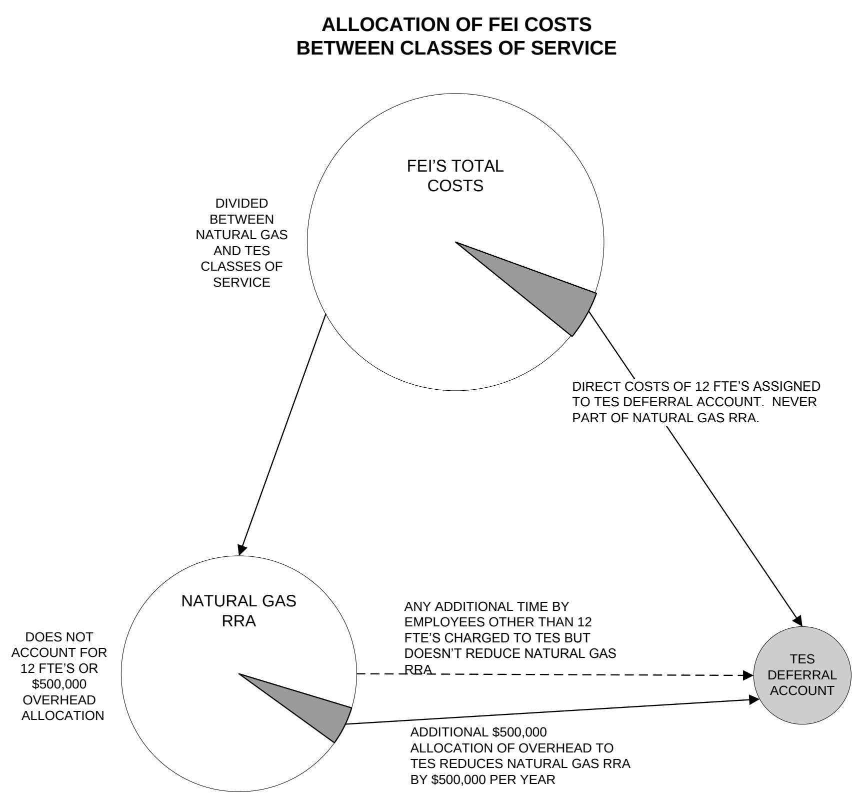
480 Exhibit B-9, BCUC 1.164.0

481 e.g. Exhibit B-9, BCUC 1.164.1 and 1.164.2 addressed the use of internal order, or "IO" numbers to track costs within the TES Deferral Account by project. BCUC 1.164.6 asked whether a COSA had been undertaken within the TES class of service.

- Second, an administrative service charge totaling $500,000 per year in 2012 and 2013 is allocated to the TES class of service. These costs show up as a cross-charge, reducing the natural gas revenue requirement in 2012 and 2013 by $500,000 annually.[482]

- Third, a limited number of other employees whose primary focus is the natural gas business do small amounts of work on TES-related matters that are not captured by the overhead allocation. Their time is recorded in time sheets and charged directly to TES. Given the small amount of work performed by each individual employee, there is no reduction in their cost on the natural gas side, i.e. their position is required to serve natural gas customers irrespective of the TES work.

This is a graphic representation of the process:



482 Exhibit B-1, pp. 275-276; Stout: T5, p. 778, ll. 7-17.

Each of these steps is described further below.

(b) Direct Costs of 12 Dedicated TES FTEs Not Reflected in Natural Gas Revenue Requirement

296. FEI has 12 dedicated FTEs working on thermal energy services.[483] The group of 12 FEI FTEs consists of employees with broad skill-sets, including engineers for assessing design and feasibility of projects, a director who provides oversight, sales staff who are TES project development focused, and support personnel.[484] The group of direct charge employees includes the Director of Thermal Energy Services, who oversees the group.[485] They operate as a largely self-contained unit,[486] as they had previously when they operated as FortisBC Alternative Energy Services Inc.. The marketing and business development work for TES is done by this TES group of employees.[487] The direct costs associated with these TES-dedicated resources do not affect the natural gas revenue requirement for the reasons described below.[488]

297. The costs associated with those individuals, i.e. compensation and all of the loadings[489] are directly charged to the TES Deferral Account.[490] These costs associated with the TES group represent a total of $1.55 million in 2012 and 2013.[491] Natural gas customers never see those costs as they are not relevant to the determination of natural gas delivery rates. Mr. Stout explained:

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[483] Some of these 12 FTE were formerly employees of FortisBC Alternative Energy Services Inc. Thomson: T5, p. 675, ll. 10-21.

[484] Dall'Antonia: T5, p. 682, ll. 11-24.

[485] Exhibit B-9, BCUC 1.164.3.

[486] Stout: T6, p. 907, ll. 8-12.

[487] Thomson: T5, p. 683, ll. 6-19; Stout: T6, p. 871, ll. 8-12.

[488] There were some questions about the costs incurred in 2010 and 2011. As indicated in the response to BCUC 1.158.3 (Exhibit B-9), the costs incurred in 2010 and 2011 that were direct charged to the TES Deferral account were $1.4M in 2010 and $1.6M in 2011, compared to the original expectation of $1.5M each year. While this information was provided, the FEU note that the forecast and the variance each year had no impact on the natural gas revenue requirements in 2010 and 2011. Similarly, the forecasts of this amount for 2012 and 2013 have no impact to the natural gas revenue requirement.

[489] Dall'Antonia: T5, p. 659, ll. 24-26. Includes overhead such as insurance, OPEB and legal.

[490] Exhibit B-15, Corix IR 2.4.6.

[491] Stout: T6, p. 876, l. 3 to p. 877, l. 5. This amount was broken down by project and resource in Confidential response to BCUC IR 1.157.1 (Exhibit B-10).

MR. STOUT: A: We are expecting approximately the $1.5 million in 2012 and '13. But those are not included in the -- just to be perfectly clear, those are not included in the O&M that's in this application for the gas class of service. So there won't be -- that 1.55 will not be charged from what's in this application under gas cost of service. They were excluded from this application and kept in a separate class of service for the thermal energy solutions.

MR. FULTON: Q: Who is paying for those FTEs? Which entity?

MR. STOUT: A: So as I said, the employees are all employees of FEI, all employees. We have segregated the employees in the TES group that we talked about, the fourteen people [12 FTE], and they have a separate class of service cost. We have not included that cost in this revenue requirement. It was excluded from that amount, or from this revenue requirement. I believe Mr. Thomson's panel discussed that to some degree.

MR. FULTON: Q: So is the $1.5 million that you are talking about for the FEI employees?

MR. STOUT: A: I think we may be going past each other. If I go to this table maybe to be clear. The thermal energy solutions employees would be the 1.5 million. That has already been taken out of the revenue requirement O&M expense for this revenue requirement application. So it is not included in the total, so there wouldn't be a cross charge for that subsequently.[492]

298. Mr. Thomson, in the testimony referenced by Mr. Stout, had similarly indicated:

MR. THOMSON: A: Yeah, there is no amounts recorded in the requested O&M for sales and marketing costs associated with TES. We haven't -- we're not asking the Commission to approve TES sales marketing costs for '12 and '13.

MR. FULTON: Q: Is that because there's been a reduction in TES activities?

MR. THOMSON: A: No no. The amounts are not in the budget that we are asking the Commission to approve. The TES costs, if you will, are separate and distinct from the natural gas revenue requirement. So they are not in our base budget for natural gas.

. . .

[492] Stout: T6, p. 876, l. 3 to p. 877, l. 5.

> MR. THOMSON: A: We're not asking for an amount to be included in the budget and then an allocation be made across or a reduction made across. They're not there to begin with, being budgeted separately.[493]

299. Apart from these 12 FTEs, there are few other FEU employees that the TES business touches. Executive time is captured in the $500,000 allocation discussed below. There are also a limited number of business development employees that, in addition to their natural gas-related business development work, provide limited support to TES. Their time is captured in the third group of costs assigned to TES.[494]

(c) $500,000 Annual Allocation of Overhead

300. The natural gas revenue requirement is only affected by the allocation of $500,000 in overhead to TES, which shows up as a cross-charge that reduces the natural gas revenue requirement.[495] The $500,000 is charged to the TES Deferral Account to be recovered from TES customers only. As such, a portion of the overhead and common costs that FEI natural gas rate payers would otherwise have to incur are being absorbed by the TES class of service.[496]

301. The amount of the forecast annual overhead charge to TES ($500,000) for the test period happens to be the same as was specified in 2010-2011 RRA NSA, but it was derived differently. In the NSA, $500,000 was an agreed upon amount, without any calculated basis.[497] However, for 2012 and 2013, the FEU undertook a study to determine what the proper allocation should be, and derived estimates of the amount of time expected to be spent on TES activity.[498] The review involved interviews with executives and various support departments[499] and considered:[500]

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[493] Thomson: T3, p. 481, l. 16 to p. 482, l. 5; Thomson: T5, p. 683, l. 6-19.
[494] Stout: T6, p. 877, ll. 6-16.
[495] Stout: T5, p. 778, ll. 7-17.
[496] Exhibit B-16, ESAC IR 2.2.1(c); Exhibit B-9, BCUC IR 1.164.5
[497] Thomson: T5, p 671, ll. 12-25.
[498] Thomson: T5, p. 673, ll. 15-18; Dall'Antonia: T5, p. 681, ll. 6-22.
[499] Exhibit B-9, BCUC 1.78.1 and Exhibit B-9-1, Attachment 78.1.
[500] Exhibit B-9, BCUC 1.159.1, 1.159.2 and 1.150.3; Exhibit B-15, Corix IR 2.3.1 and 2.4.3.

- Executive: time for four executives, including Mr. Stout and Mr. Walker, to review current status of projects, monitor status of projects and reviewing and approving potential projects;[501]

- 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 TES Deferral Account (including desktops/laptops and furniture);

- Facilities: allocation of facilities costs for employees charging directly into the TES Deferral Account. The facilities include space in the Surrey Operations Centre, Garbally/Langford and Burnaby facility.[502]

302. There is no board of directors' time allocated because, at this time, the time and effort spent on the thermal energy business by the Board is negligible given the scale of the TES business.[503] To date, there are only 3 signed contracts for TES service less than $5 million, none of which have been approved.[504] As Mr. Dall'Antonia explained:[505]

> The board looks at the business. We meet quarterly, but there is an annual business plan. There is a reference to all the business we're doing, and in there there is discussion of alternative energy. And in that there will be a discussion of the thermal energy piece.
>
> But I can't recall any specific resolutions or specific projects that the board has been involved in, that they have approved. So there has been no direct

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[501] Exhibit B-9, BCUC IR 1.160.1. Incremental costs for travel, training or business development would be charged directly to the TES deferral account: BCUC 1.159.3.

[502] Exhibit B-9, BCUC 1.159.1, 1.159.2 and 1.150.3; Exhibit B-15, Corix 2.3.1; 2.4.3.

[503] Exhibit B-15, Corix IR 2.3.1.

[504] Dall'Antonia: T3, p. 388, l. 22 to p. 389, l. 10.

[505] Dall'Antonia: T3, p. 389, l. 11 to p. 390, l. 6.

> allocation of board costs. We don't see the board taking any oversight role. There is knowledge of what's going on in the TS business. There is a delegation down to the executive. Mr. Walker's time, Mr. Stout's time specifically, a bit of my time, a bit of Mr. Thomson's time, is allocated in that $500,000 from an oversight perspective. And that we view as appropriate. But we have not included board function costs, or board costs, at this time.
>
> As we hope the business develops over time, we will re-look at that allocation. But this allocation is really looking over the next two years, and we believe it's appropriate at this time.

303. The number generated by that study was $497,311 in 2012 and $511,685 in 2013, reflecting an inflationary change but a consistent resource commitment.[506] The detailed breakdown of these amounts is included as Attachment 78.1 to BCUC IR 1.78.1.[507] The FEU used the rounded figure of $500,000 in both years for the purpose of establishing the extent of the reduction to the natural gas revenue requirement.

304. Mr. Dall'Antonia explained that the normal allocators rely on factors such as customer count (such as the Core Market Administration Expense allocation) and assets, payroll and revenue (the Massachusetts Method used for corporate services).[508] Such methodologies yield lower allocations to TES.[509] However, the FEU wished to recognize in the allocation that there is time and resources being spent on TES, and thus reduce the natural gas revenue requirement in 2012 and 2013. Thus, the FEU used a management estimate of time. Mr. Dall'Antonia expressed his conviction that the allocation was based on a fair approach:

> The way we allocate typically is on a couple of different drivers. One will be number of customers. One will be asset base. We right now don't have customers. We have no real assets other than the deferral account. So the allocation of overhead is really based on management estimate of time and the resources, the space, the IT being used. So again, it was an attempt to undertake a fair allocation of the time, and that's what we believe it is.[510]

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[506] Exhibit B-9, BCUC IR 1.78.1. Dall'Antonia: T5, p. 678, l. 12 to p. 679, l. 6. Note that Mr. Dall'Antonia used the incorrect figures in that passage; they were corrected to align with what appeared in BCUC IR 1.78.1 at T6: 868: ll.4-11.

[507] See also the response to Corix IR 2.3.1 (Exhibit B-15) for further explanation about some specific allocations.

[508] Dall'Antonia: T5, p. 680, l. 10 to p. 681, l. 5.

[509] Dall'Antonia: T5, p. 702, l. 18 to p. 705, l. 1.

[510] Dall'Antonia: T5, p. 679, ll. 17-26.

305. If revenues were used as the allocator, the allocation would be less than \$500,000 as there is no forecast revenue in 2012 or 2013 for TES. If the Massachusetts method (the method used to allocate corporate costs to the FEU) were used, it would be "quite a bit less" than \$500,000. If FEU were to use something akin to the transfer pricing methodology used for NRBs to allocate overhead to TES, the result would similarly have been less than \$500,000.[511] The fairness of the allocation from the perspective of natural gas customers is reinforced by the fact that the shared services allocation to FEW is approximately \$300,000, or 60% of the TES allocation. FEW has close to 3,000 customers and a \$43 million rate base. TES has no approved projects and no customers.[512]

306. The allocation methodology is appropriate for the next two years, but will be revisited. As the TES business grows, the FEU will examine other ways of allocating costs including a shared services model.[513] However, Mr. Dall'Antonia – citing the current shared services allocation to FEW – emphasized that other methodologies may or may not result in an increased allocation to TES.[514]

(d) Other Cross-Charges for Marketing and Time Spent

307. A third category of TES costs is costs associated with TES business development work undertaken by employees that primarily work on developing natural gas, where that work is not otherwise reflected in the \$500,000 overhead allocation. The use of such resources is charged directly to the TES Deferral Account.[515]

308. In terms of human resources, most TES-related work can be handled by the group of 12 FTE focused exclusively on TES. However, as Mr. Stout stated: "…there may be the odd time, as there was in 2010 and '11, and as I discussed with Mr. Bursey yesterday, that other employees on the gas side of things may have a lead and pass that on to the TES group. And in

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[511] Dall'Antonia: T5, p. 702, l. 18 to p. 706, l. 14.

[512] Dall'Antonia: T5, p. 677, ll. 21-25; Dall'Antonia: T3, p. 388, l. 22 to p. 389, l. 10.

[513] Dall'Antonia: T5, p. 691, l. 18-25.

[514] Dall'Antonia: T5, p. 677, l. 21 to p. 678, l. 3.

[515] Exhibit B-15, Corix IR 2.4.6.

that case they will charge the time into that TES deferral account."[516] The amount of time that each these individuals engages in the thermal energy services business is insignificant at this time relative to the total amount of work they do for natural gas in a particular year.[517] As such, the potential for cross charging does not result in a reduction of headcount attributed to the natural gas service with savings for the natural gas class of service in 2012 and 2013.[518]

309. The cost of marketing materials directed at promoting TES is direct charged to the TES deferral account.[519] The FEU charge a portion of marketing materials that speak about TES and relevant sponsorships to the TES deferral account.[520] This includes a portion of the sponsorship costs for local government organizations, such as the UBCM, as those sponsorships have natural gas, electricity and thermal energy components.[521] The allocation methodology for collateral and sponsorships relied on judgment, and was reasonable, particularly given that the use of established methodologies would have yielded no allocation to TES.[522] The sponsorship for Canadian District Energy Association was allocated completely to TES, even though there are gas customers in attendance.[523] Mr. Stout's evidence in response to Mr. Commission counsel's questions, which delved into allocations as little as $1000, served to highlight that the Companies are committed to maintaining a proper cost allocation.

(e) Systems to Ensure Reliability of Direct Charges

310. There was significant focus in this proceeding on the accuracy or reliability of the direct charges addressed through timesheets. The discussion on timesheets is most relevant to the third category of costs above (i.e. employees that work primarily on natural gas matters, but provide small amounts of support for TES), since all costs associated with the 12 FTEs who

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[516] Stout: T6, p. 871, ll. 14-19.

[517] Stout: T6, p. 877, ll. 6-16. Mr. Stout indicated that the charges were $192,000 in 2010 and "There may be some minor charges in 2011."

[518] Stout: T6, p. 878, ll. 7-11.

[519] Stout: T6, p. 928, ll. 9-12.

[520] Stout: T6, p. 921, l. 24 to p. 922, l. 15.

[521] Stout: T6, p. 926, ll. 17to 26.

[522] Stout: T6, p. 926, l. 17 to p. 931, l. 7.

[523] Stout: T6, p. 928, ll. 1-6.

work on TES are assigned to the TES Deferral Account and the overhead is allocated based on a study that estimated management time. There are relatively few employees in the organization apart from the 12 FTE that perform any work on TES in addition to their natural gas-related responsibilities.

311. The FEU have established and documented employee timesheet completion practices. Employees are trained and advised on how to complete time sheets and code expenses appropriately.[524] The importance of timekeeping extends well beyond just TES, and thus the emphasis on timekeeping is more general. Timekeeping is equally important on capital projects, for instance, where accurate timekeeping ensures that the appropriate amount of costs is capitalized. In the case of the relatively few employees that work on both classes of service, as with any timesheet allocation, employees are expected to attribute their time on their timesheets to the best of their ability, exercising considered judgment in cases where there is overlap in specific tasks.[525] The established time sheet policies and standards within the FEU that govern time tracking are equally appropriate for TES allocations.[526] Compliance with the policy is reviewed and enforced.

(f) Financing Costs

312. Corix has raised the issue of how financing costs are allocated. As this application is concerned with setting natural gas rates, the issue of what the financing costs are for TES projects is not relevant except to the extent that it might affect natural gas rates in the test period. There is no evidence that financing costs for the natural gas class of service have been affected in any way by the TES class of service. The FEU stated: “Given the very small size of the thermal energy services investments relative to gas investments, the FEU do not anticipate any impact on the natural gas revenue requirements associated with providing financing for thermal energy services projects.”[527]

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[524] Exhibit B-17, BCUC IR 2.79.1.

[525] Exhibit B-15, Corix IR 2.4.3(b)

[526] Exhibit B-15, Corix IR 2.4.4; Exhibit B-17, BCUC IR 2.79.1 and 2.79.4.

[527] Exhibit B-15, Corix IR 2.2.6 to 2.2.10.2.

(g) Summary Regarding TES Cost Allocation

313. The evidence is that costs associated with the provision of thermal energy services have been entirely excluded from the natural gas revenue requirement. Natural gas customers are benefitting to the extent of $1 million in the test period by virtue of the allocation to TES. The allocation method is fair and reasonable and the allocation should be approved for the test period.

PART EIGHT: CAPITAL EXPENDITURES

314. The FEU's revenue requirements for 2012 and 2013 are impacted by the capital expenditures forecast for 2012 and 2013, which are described in section 6.2 of the Application. The FEU's capital expenditures are divided into three categories as explained below:

- **Sustainment Capital** – Includes expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load, and replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations;
- **Growth Capital** – Includes expenditures for the installation of new mains, services and meters and biomethane equipment; and
- **Other Capital** – Includes expenditures for Facilities, Equipment and IT.

315. Capital expenditures also include CPCN projects and are offset by CIAC.

316. The following subsections will first discuss FEU's management of capital expenditures and then address each of the categories of capital expenditures.

A. MANAGEMENT OF CAPITAL EXPENDITURES WITHIN APPROVED BUDGET

317. The FEU manage capital expenditures within the total capital funding approved in the annual capital budget. The majority of capital projects included in the capital budget normally proceed as planned.[528] There may, however, be refinements to projects due to changes in scope and timing as projects proceed further along in the development cycle and with the passing of time. Cost estimates or timelines of projects may be revised closer to the projects' start dates as a result of project dependencies and the availability of resources that may affect the completion of the projects.[529] When there are funding increases required for some projects, other existing capital activities may be re-prioritized where possible to make room within the budget for the funding required, without affecting the safety and reliability of the FEU's system. In the situation where a budgeted project does not proceed as planned, the

[528] Exhibit B-6, BCOAPO IR 1.11.3.
[529] Exhibit B-6, BCOAPO IR 1.11.3.

FEU work to identify and advance replacement projects that address other operational requirements.[530]

318. The FEU's success in managing capital budgets is demonstrated by the fact that FEI's capital expenditures for 2010-2011 are projected at approximately $201 million over two years, slightly less than the $204.3 million total capital expenditures approved by Commission Order G-141-09.[531] The difference between approved and actual 2010 and projected 2011 capital expenditures has been trued-up in this revenue requirement as the lesser amount is embedded in the opening plant balance.[532] Similarly, variances in capital expenditures and gas plant additions will be trued up the next time rates are determined, since the actual results will be embedded in the opening plant balance.[533] In this way, benefits of lower capital costs are passed on to customers.

319. The fact that the FEU must respond to changing circumstances as the test period unfolds gave rise to questions about the financial impacts of potential variances from the overall capital budget for 2012-2013. The impact to the overall cost of service is complex and depends on a number of factors.[534] Variances in the gas plant-in-service additions are only one item that could affect the actual investment in Rate Base as well as the achieved Return on Equity.[535] For example, even if capital expenditures were less than forecast it does not necessarily mean that additions to gas plant in service will vary as more of the opening work-in-progress could be completed leaving gas plant in service additions and the Rate Base unchanged. Reduced expenditures could also be a function of fewer customer additions or delays in the progress of project completion in which case capital expenditures would take place later in 2013 or 2014 leaving the total spend for the projects unchanged.[536] As a concrete example, the impact to the shareholder of the 2010 capital expenditure variance of $7.6 million

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[530] Exhibit B-6, BCOAPO IR 1.11.3.

[531] Exhibit B-21, Evidentiary Update, p.5.

[532] Exhibit B-6, BCOAPO IR 1.6.1.

[533] Exhibit B-6, BCOAPO IR 1.6.1.

[534] Roy: T3, p. 324, l. 13 to p. 332, l. 19.

[535] Exhibit B-6, BCOAPO IR 1.6.1.

[536] Exhibit B-6, BCOAPO IR 1.6.1.

is a **loss** of approximately $540 thousand. Although actual capital expenditures are less than approved and result in lower depreciation and interest expense, a loss to the shareholder occurred in this circumstance because tax expense was higher than approved. The tax expense was greater than approved because a large component of the $7.6 million variance is in IT expenditures which have high CCA rates.[537]

320. In approving the capital budget for 2012-2013 the Commission should have regard to the significant body of evidence that the FEU's capital budget reflects currently identified safety, reliability, operational and customer requirements. The vast majority of these projects will proceed as planned, and the potential that some priorities must evolve to meet changing circumstances should not drive the determination of the budget itself. Having some flexibility is ultimately beneficial for customers.

B. SUSTAINMENT CAPITAL EXPENDITURES AND THE LTSP

321. The FEU are seeking approval for forecast sustainment capital budgets for distribution and transmission assets of $85.0 million in 2012 and $89.6 million in 2013. This represents incremental spending of $25.6 million and $30.2 million in 2012 and 2013 respectively over 2011 approved amounts for the same purposes.[538] This two-year sustainment spending includes:

- Expenditures for meter recalls and meter exchange programs;
- System reinforcements to the distribution and transmission systems to maintain capacity to meet existing customer demand and forecast load;
- Replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and
- Expenditures for main and service alterations and renewals.

[537] Exhibit B-40, Undertaking No. 14.
[538] Exhibit B-1, p. 343, as updated by Exhibit B-1-3.

322. Section 6.2.2 of the Application[539] describes the sustainment capital activities for each of the utilities, including 2010 actuals, 2011 projected and 2012-2013 forecast expenditures. All projects and multi-year programs with a cost of over $1 million are described. Additional projects and multi-year programs are described in response to BCUC IR 1.91.1.[540]

323. No material issues were raised with respect to these projects or expenditures.[541] Rather, the focus of participants was the Long-Term Sustainment Plan (LTSP), which is a significant new initiative and a major driver of incremental sustainment capital costs in the test period. The estimated LTSP-related 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.[542]

324. The LTSP is described in the Application.[543] The primary driver of the LTSP is the risk of aging infrastructure.[544] 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 assets will need to be replaced.[545] In addition, the FEU are facing increasing regulation and expectations from stakeholders such as the Oil and Gas Commission.[546]

325. The LTSP, which the FEU began developing in 2010, enhances existing processes used for development of sustainment capital budgets, in particular, by providing a life cycle view of asset health and management instead of the traditional one to five year view of assets. Significant advance planning is required in the face of the pending wave of asset retirements 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

[539] In particular, pp. 343 to 359 of Exhibit B-1, as updated by Exhibit B-1-3.

[540] Exhibit B-9 (pp. 306-308).

[541] e.g., see Exhibit B-9, BCUC IR 1.90.1 to BCUC IR 1.93.2.

[542] Exhibit B-9, BCUC IR 1.157.1. Note that the LTSP is not budgeted and tracked as a separate project. Bell: T7, p. 1163, ll. 3 to 14.

[543] Exhibit B-1, pp. 336 to 342.

[544] Bell: T7, p. 1158, ll. 6 to 12; Exhibit B-1, pp. 336 to 338.

[545] Exhibit B-9, BCUC IR 1.57.1.

[546] Exhibit B-1, pp. 338-340.

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.[547]

326. Mr. Bell explained that the current five year planning approach, while serving the Companies well to date, will give rise to problems in the context of the pending wave of retirements that is occurring due to the age of the system assets:[548]

> MR. BELL: A: No. I wouldn't say that it was a decision that creates a glut. It's just the length, the longevity of this -- of these assets. So, if you go back to when these assets were put in the ground, in the seventies, that was the boom time. You had a lot of houses being built. We were running gas out to the communities, out into rural areas. We were building transmission lines and it was just the fact that there was a lot of assets went in the ground at that time.
>
> And so, that -- those groups, they start to age, and as you -- you know, you can extend their life by certainly, you know, adding cathodic protection by doing proper maintenance on it, and keeping it as long as you can. But at the end of the day, it's going to try and turn back -- a steel pipe will try to turn back to dirt. It just -- it's -- it will wear out. Regulators will wear out. And so it's just the age of the assets. We've -- we have maintained these assets very, very well, and -- you know, but at the end of the day, they have -- they are coming to the end of their life, and we want to have this longer-term plan to have a look at exactly -- you know, from today, where these assets are going to, we believe, start to fail, so that we can then make the right decision within that next 20-year planning window, and not have a huge chunk of assets, you know, hit the start of a five-year planning window, and we just go, "Okay, now we have a very, very short period of time to deal with these assets."
>
> So, it's really around getting that longerterm picture and clearly understanding what that looks like. And then building that replacement plan properly.

327. Mr. Bell described the LTSP at a high-level as involving:[549]

> … really getting a clear picture of the asset health today, the life expectancy of it, and then the mitigation factors of how we're extending that out. And then we

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[547] Exhibit B-9, BCUC IR 1.57.1.

[548] Bell: T7, p. 1073, l. 20 to p. 1075, l. 1.

[549] Bell: T7, p. 1157, ll. 8-22.

> develop the plan that says, okay, here, we're going to have to replace this group of assets on this date and can we move it forward, or is there something we should do to try and push it out?

328. The current investment required to put in place the LTSP, while significant, will yield greater benefits for customers in the long-term by permitting more effective system planning in the face of the coming wave of asset retirements.

C. GROWTH CAPITAL EXPENDITURES

329. The FEU's forecast growth capital expenditures are described in section 6.2.3 of the Application. Growth Capital expenditures include the installation of new mains, services, meters and regulators and expenditures for biomethane projects.[550] The primary drivers for Growth Capital expenditures are the number and type of new services and mains. These in turn are driven by customer additions, which are dependent on new housing, development activity and market capture.[551] There were relatively few questions raised with respect to forecast growth capital expenditures. In the subsections below, the FEU consider the areas explored during the proceeding. (The Main Extension test and specific main extensions raised in the proceeding will be considered in Part Ten below.)

(a) Trends in Mains and Services Activity Levels

330. Some information requests probed the trends used to forecast growth capital expenditures. As discussed below, the methodology used by the FEU is appropriate and incorporates the lower mains and services activity levels experienced in 2010 and 2011.

331. Growth capital expenditures are derived from activity and unit forecasts based on the same methodology used in previous years. 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

[550] There are no capital expenditures forecast for NGV fueling assets in either 2012 or 2013. (Exhibit-1-3, updated p. 365 to Application.)

[551] Exhibit B-1, p. 359 to 364, as updated by Exhibit B-1-3.

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.[552]

332. Using the three-year historical ratio is important since 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. Over the longer term of three years these timing differences between main and service installations are reduced.[553]

333. Using the same forecast methodology, the lower customer additions and unit costs experienced in 2010 and 2011[554] are incorporated in the growth capital forecasts.[555] As seen in the Application, the forecast activity levels, unit costs and expenditures are lower than approved for 2010 and 2011.[556]

(b) Biomethane Projects

334. Capital invested in interconnection facilities and upgrader equipment for Biomethane projects during the test period is forecast to be $3.1 million and $3.6 million in 2012 and 2013, respectively. As discussed in the Biomethane Report in Appendix J to the Application, FEI's overall capital costs incurred to date from the two approved supply projects are well under the overall approved budget.[557] The cost of service (i.e. depreciation, income tax

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[552] Exhibit B-1, p. 361.

[553] Exhibit B-9, BCUC IR 1.94.3.

[554] As shown in Table 6.2-12, the FEU's actual growth capital expenditures in 2010 and 2011 were below approved levels due to lower mains activity levels and costs and lower services costs than forecast, offset by a higher levels of services activity in 2010. (Exhibit B-1, p. 360, as updated by Exhibit B-1-3. Exhibit B-1, pp. 362 and 364.)

[555] Exhibit B-17, BCUC IR 2.60.1.

[556] See, Tables 6.2-14 and 6.2-15 on pp. 361 and 363 of the Application as revised by Exhibit B-1-3.

[557] The overall costs for the Catalyst project came in well under the approved amount. For the Upgrading plant under CSRD, FEI anticipates spending an additional $300,000 from the original approved amount to accommodate for the design change as recommended by Xebec to manage higher levels of nitrogen while still meeting final biomethane specifications. The BVA will capture such variances and will reflect any adjustments to the BERC rate based on deferral account balances at that point in time and these increased costs for the Upgrader will be recovered from biomethane customers who elect into the program. (Exhibit B-1, Appendix J.)

and earned return) of the capital expenditures on the upgraders[558] are captured in the BVA and recovered from Biomethane customers only.[559]

335. 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.[560] 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.[561]

336. The FEU submit that it is most appropriate to recover these Biomethane program costs in the forecast period to match the time in which they are incurred. Biomethane is a component of the FEU's natural gas business and operations and should be treated consistent with other forecast costs that apply to all customers.[562]

(c) Conclusion

337. The FEU submit that its forecast growth capital expenditures are reasonable and prudent and the exploration of the forecast has given rise to no material issue in this proceeding.

D. FACILITIES AND EQUIPMENT CAPITAL EXPENDITURES

338. Facilities and Equipment Capital expenditures include the acquisition or leasing of land, station buildings, facilities equipment, telecommunications infrastructure, specialized

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[558] $2.1 million in 2012 and $2.6 million in 2013.

[559] Exhibit B-1, Appendix J, p. 10, Table J-4.

[560] Exhibit B-9, BCUC IR 1.183.3.

[561] Exhibit B-9, BCUC IR 1.183.2.

[562] Exhibit B-9, BCUC IR 1.187.1.

tools and equipment, and radio system upgrades. Section 6.2.4 of the Application[563] describes the forecast capital expenditures for these items. Further detail is provided in response to BCUC IR 1.95.2 (Exhibit B-9). The forecast is based on known and anticipated projects and the expenditures are required to meet the ongoing business requirements of the FEU.

339. The only item within the Facilities and Equipment Capital expenditures forecast that was explored in the hearing related to the North Vancouver Muster Station. As described in the Application, the North Vancouver Muster Station is currently leased and, due to an expansion for the Landlord, FEI 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.[564]

340. The Application outlined FEI's expectation of purchasing land for the North Vancouver Muster for an estimated $2 million, with the estimate being based on the requirement of approximately .5 acre at the current market rate of $85 square foot.[565] The FEU can now advise that it has been able to purchase a site in the North Vancouver area for the $2 million budgeted, and the amount will enter rate base in 2012 when it is placed into service (i.e. the proposed rates are not affected). 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, which is still required.[566]

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[563] Exhibit B-1, pp. 371 to 375, as updated by Exhibit B-1-3.
[564] Exhibit B-1, p. 372.
[565] Exhibit B-1, p. 372. Exhibit B-9, BCUC IR 1.95.1.
[566] Exhibit B-1, BCUC IR 1.95.2.

E. IT CAPITAL EXPENDITURES

341. The FEU's forecast IT capital expenditures are discussed in the Application Section 6.2.5, pages 377 and 378.[567] The FEU are forecasting $20 million in IT capital expenditures in each of 2012 and 2013. The evidence on the topics explored is discussed below.

(a) 2010 Actuals Varied Due to One Time Events / 2011 On Budget

342. There were a number of information requests and questions from Commission staff at the oral hearing regarding the 2010 IT expenditures, which were $3.6 million below approved levels. The factors that led to under spending in 2010 were one-time in nature and will not impact 2012-2013 forecasts.

343. As explained in the Application, the reason for the lower than approved levels was primarily due to the approval of the CCE Project which refocused key IT and business resources that otherwise would have been allocated to other IT initiatives. At the time of budget planning, the CCE Project was not yet approved and the budget was created assuming access to all required resources.[568] When the CCE Project was approved, IT personnel had to be redirected to support the execution of that project. 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. As a consequence, 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.[569]

344. Mr. Legge explained:[570]

> There were projects that were put forward in '10 and '11 that competed for the same resources that customer ultimately required. And so there were decisions

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[567] Exhibit B-1.

[568] Exhibit B-1, p. 375.

[569] Exhibit B-9, BCUC IR 1.96.1.

[570] Legge: T7, p. 1187, ll. 1 to 18 and p. 1188, l. 11 to p. 1189, l. 2.

to defer those projects because we couldn't execute those projects against the same time as customer was done. It would have brought undue risk and uncertainty to the customer project. So the conscious decision was made to defer those until those projects were done.

There was a collection of projects, as I said, and as the process explains, that compete for the dollars. So again, as part of the prioritization process, one of the criteria is the ability to execute those particular projects. So they were deferred, they go back and compete against the other projects that are being asked for in '12 and '13. So they have to go back and be evaluated against the new set of projects that have also arisen since that time.

. . .

MR. FULTON: Q: Okay. And are those dollars included in the $20 million forecasts at page 375? The dollars that weren't spent in 2010?

MR. LEGGE: A: They're not the same dollars. The projects that were deferred, or arguably part of the reason it wasn't spent was because it was deferred. Part of the reason they weren't spent was because there were pressures on the operating side for the OpEx component, which would also have been required to spend in execution of some of the projects. So the projects themselves -- we budget from an annual year to year. We don't roll budgets. They don't flow, they don't get compounded or added to a following year. Every year is treated as a discrete year. So some of the competition for projects that potentially had customer not gone forward, would have competed in '10, those projects are, for the most part, are on the list, I believe, for execution in '12 and '13.

345. The deferral of these projects did contribute to a lower actual rate base in 2010 than what had been approved. However, isolating one component of the cost of service does not provide a full picture for the year. 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.[571] Although 2010 rates cannot be revised now, the effect of the under spending was actually unfavourable for the shareholder.[572]

346. The 2011 projection for IT expenditures is on budget at $17.5 million.[573]

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[571] Exhibit B-9, BCUC IR 1.96.1; Exhibit B-17, BCUC IR 2.64.1.

[572] Thomson: T3, p. 331, ll. 7 to 13.

[573] Exhibit B-1, p. 375.

347. The FEU submit that the 2012-2013 budget should be based on the evidence regarding the basis for that budget, and not what occurred in 2010.

(b) 2012-2013 Forecast is Reasonable

348. The FEU are forecasting $20 million of IT capital expenditures for each of 2012 and 2013. This represents an increase of $2.0 million for FEI and $500 thousand for FEVI from the 2011 total of $16.0 million and $1.5 million. 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.[574]

349. Mr. Legge described the various needs driving projects in 2012 and 2013 as follows:[575]

> Each project that comes in has a business case that -- or a value proposition of why the project is required. Some of them are just to maintain things. There will be some infrastructure type projects where some assets just need to be replaced. They've out-listed -- you know, they've outlasted, they're required, they'll need to be done. Some of them are increasing in terms of security, so they're are risk mitigation kinds of thing. You're seeing a lot more intrusions. You're seeing a lot more data needing to be encrypted. You're seeing a lot more people with mobile devices who have the ability to move data around, and there's additional security effort that goes into it. If we look at part of the drivers in the response to BCUC IR 97.1, those are kind of the top two categories of -- that are more infrastructure-driven.
>
> Of the enhanced capabilities, that's one of the criteria to determine whether projects go forward or not. There is very little that we do that's just nice to have. There is so many demands on what people are trying to do to find efficiencies, or to find things, there are varying degrees. And that's what that whole process, identified in 97.1, is meant to help drive out, is the prioritization of the project. So only the highest value projects that offer the best return for the business case that's being put forward are prioritized and executed first.

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[574] 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. (Exhibit B-9, BCUC IR 1.98.2.)

[575] Legge: T7, p. 1184, l. 7 to p. 1185, l. 8.

350. The capital request for IT investment is forecast at an amount in 2012 and 2013 that can prudently be executed while meeting the top priorities of the business.[576] As stated by Mr. Legge:[577]

> MR. FULTON: Q: Let me approach it this way, then. Do you at least anticipate that you will be spending the $20 million in each of 2012 and 2013 on those capital projects?
>
> MR. LEGGE: A: Yes, we certainly believe that -- that's why we put the number forward, is that that is going to be one of the constraints in terms of what we can actually execute. But we believe that we'll spend the dollars that we're asking for.

As discussed above, it is actually unfavourable to the shareholder for the utility to under-spend on IT capital because IT capital has higher depreciation rates.[578]

351. 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 have a total cost of $31,000 thousand[579] and $23,826.4 thousand in 2012 and 2013, respectively.[580] From these many projects, the FEU apply a well-established methodology known as IT Project Portfolio Management (PPM) to evaluate, prioritize, and coordinate the requirements of the various operating business units and technology, thus enabling more effective capital investment decisions. PPM compares and prioritizes potential IT project investments based on the project's value contribution to the organization's goals, irrespective of where the initiative originated. Those projects with the greatest contribution and alignment will receive highest priority. The priority of each project guides the financial and resource allocation for the portfolio. Prior to execution, all approved IT Project Portfolio projects must still acquire formal authorization for capital investment through written justification (business casing) which reconfirms the business value of undertaking the

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[576] Exhibit B-1, p. 378, Revised May 16, 2011.

[577] Legge: T7, p. 1190, ll. 6 to 14.

[578] Thomson: T3, p. 331, ll. 7 to 13.

[579] Legge: T7, p. 1181, l. 15.

[580] Exhibit B-9, BCUC IR 1.97.1.

project and validates the assumptions made in the initial establishment of the IT Project Portfolio.[581]

352. Mr. Legge explained the relationship between the budget of $20 million and the total cost of projects to be evaluated as follows:[582]

> Sure. Well, the biggest driver for it is that the table in the response to BCUC 97.1 represents the total ask coming from the business, in terms of the overall projects that are being asked to be done. Part of the process that we go through, and there is a kind of a figure above that page which kind of explains the process we go through to evaluate all of the asks. We don't pre-edit. We don't -- IT doesn't make a pre-determination about which projects are valid or not valid. So, we do the cumulative ask of all the projects, and we try to assign an estimated value of the effort of the project, the nature of the project, the resources required to do that particular project. What cost components or drivers for it, whether they have some of the training cost components to it, which come out of a different funding bucket, whether they're feasibility projects, which will spawn capital projects.
>
> And we go through that process, and then we look at our ability to execute all of the projects. We look at the combinations of the projects, other ways that we can combine projects, other projects that are mutually exclusive, other projects that have very definitive dates or requirements when they have to be done, or to meet code or compliance. Which kind of sets the foundation for which -- you know, what the execution of the year looks like.
>
> And then we look at that, the nature of those projects, and try to do an estimation on what we believe to be the number that we think we can execute on, based on the makeup of the projects. And that's how we kind of get it down to -- some projects will be over-estimated based on -- they're relatively new to the group. We haven't spent enough time to determine, you know, the details of how that project will actually get executed. Some of them are very detailed. We've known about them for a while, and they're just kind of waiting their turn in the queue.
>
> And we sort -- we look through to try and make the best balance of the resources we have, the timings and the drivers for the projects, and look to see what's the optimum number we can balance to get the most throughput of the projects that pass, and are deemed to be worth going ahead with.

[581] Exhibit B-1, pp. 377-378.

[582] Legge: T7, p. 1181, l. 22 to p. 1183, l. 18.

> And so the number of asks will always exceed the number that's practical to execute on. So we try to balance the best we can to find that balance. And that's the number that's in the table in the filing.

353. The Technology Roadmaps mentioned above provide direct input into the IT portfolio selection process to identify and set candidate 2012-2013 IT projects. The IT technology roadmaps describe the transformation path for IT assets (applications, systems and skills) over an extended period of time, aligning IT capital expenditures with long term vision of its IT assets.[583]

354. The FEU submit that the need for IT capital expenditures has been established, that the Companies have prudently planned for IT expenditures using its technology roadmaps, and that a rigorous process is in place to ensure that only the highest-value projects proceed. The forecast capital expenditures are less than the current amount of proposed projects and reflects an amount that can be prudently executed. The FEU submit that the forecast should be accepted as filed for the purpose of calculating 2012 and 2013 rates.

F. CONTRIBUTIONS IN AID OF CONSTRUCTION

355. The 2010 actual, 2011 projected and 2012 and 2013 forecast CIAC recoveries are described in section 6.2.6 of the Application.[584] As explained in the responses to BCOAPO IR 1.30.1 to 1.30.3,[585] FEI's CIAC projection for 2011 and CIAC forecasts for 2012 and 2013 are based on an internal spending model that takes into account historical actuals over the past five-year period coupled with actual current spend to date for all capital activities. FEW and Fort Nelson do not project or forecast CIAC recoveries because specific receivable projects are not known or forecasted in advance. Actual CIAC recoveries for FEW and Fort Nelson have been very minimal in the last five-year period.

356. The FEU submit that its forecast CIAC recoveries in 2012 and 2013 should be accepted as filed.

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[583] Exhibit B-9, BCUC IR 1.98.1.

[584] Exhibit B-1, pp. 379 to 380, as updated by Exhibit B-1-3.

[585] Exhibit B-6.

G. CPCN PROJECTS

357. Included in rate base for the purpose of calculating 2012 and 2013 rates are projects for which the Commission has granted a Certificate of Public Convenience and Necessity (CPCN) and that are forecast to go into service during the test years. Anticipated projects which would require a CPCN are subject to Commission approval and do not impact rates in 2012 and 2013.[586]

358. CPCN projects entering rate base in 2011 through 2013 that were explored in the proceeding are considered below. These previously approved projects represent a significant portion of FEI's propose rate increase.

(a) Fraser River Crossing Project

359. The Fraser River South Arm Crossing Project, for which a CPCN was granted by Order No. C-2-09, consists of a new crossing using horizontal directional drill technology to replace the 24 inch and the 20 inch since there is a risk of a major seismic event. The estimated cost at completion for the Project is $36.3 million including AFUDC.[587] The pipes are now in service.[588]

360. As explained in FEI's latest quarterly report[589] and in response to BCUC IR 2.41.4, the estimated cost at completion is now higher than the Project control budget of $29.75 million due to issues related to problems which the construction contractor and its HDD subcontractors encountered during the execution of the Project. In summary:

- A 10 month delay in the Project was due to the HDD sub-contractor having a major failure of its equipment, and consequently abandoning the first 20 inch HDD attempt. FEI believes the failed attempt to be to the account of the construction contractor under FEI's guaranteed completion contract with the

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[586] Exhibit B-1, pp. 382 to 383; Exhibit B-17, BCUC IR 2.41.1.
[587] Exhibit B-1, p. 381.
[588] Bell: T7, p. 1153, ll. 23 to 25.
[589] Exhibit B-17-1, Attachment 41.4 filed confidentially.

construction contractor. FEI's incremental project costs attributable to this ten month delay include additional geotechnical investigations and design of a new 20 inch HDD drill path, as well as project management, project inspection, and ongoing activity to ensure adherence to applicable technical and environmental codes and standards.

- An additional delay of twelve months arose in July 2010 from an incomplete 24 inch HDD pull-back of 55 metres. FEI believes the incomplete 24 inch pullback to be to the account of the construction contractor under the FEI's guaranteed completion contract with the construction contractor. The FEI's incremental Project costs attributable to this further 12 month delay include re-designs, assessments of the construction contractor's methodologies, procurement of induction bends for the 24 inch pipeline for the south side tie-in, incremental project management costs and taking remedial steps to ensure satisfactory environmental compliance and corrosion protection of the 24 inch pipeline.

- The delays totaling 22 months have required FEI to extend agreements in place for land use and access.

361. As detailed above, the delays experienced have been the result of factors beyond FEI's control. FEI's contracting process includes risk mitigation measures so that the construction contractor bears a significant portion of the risks, such that FEI is only responsible for the incremental costs associated with the delay as described above.[590] All Project costs have been prudently incurred and will result in long-term used and useful assets which are critical to the gas transmission system serving FEI's Lower Mainland customers. Thus, FEI submits that the costs are appropriately included in rate base and recovered from customers.[591]

[590] Also see testimony of Mr. Bell at T6, p. 1048, ll. 13 to 24.
[591] Exhibit B-17, BCUC IR 2.41.4.

(b) Customer Care Enhancement Project

362. The total project costs for the CCE Project are on track with the total project spending as approved by BCUC Order No. C-1-10 of $115.5 million (plus or minus 10% and including AFUDC).[592] The Customer Care Enhancement (CCE) Project is discussed above in *Part Five, Section E: Customer Service*.

(c) Mount Hayes LNG Storage Facility Project

363. The Mt. Hayes LNG Storage Facility Project includes construction and ownership of an LNG peak-shaving storage facility at Mt. Hayes near Ladysmith, and various associated facilities to connect the LNG Storage Facility to Vancouver Island's natural gas transmission system.[593] The Project is on schedule and the Mt. Hayes LNG Facility was placed into rate base on May 31, 2011 so that the tank is in use for the upcoming winter season. A recent project cost analysis suggests that there is potential for the total project costs to come in approximately $1 million under budget. Although the FEVI has included budgeted costs equal to the approved CPCN amount within the financial schedules in the Application,[594] if the overall project costs do end up being less than the approved CPCN amount, the savings in 2011, 2012 and 2013 will be captured in the RSDA. Furthermore, the plant in service and rate base will be reset in 2014 to include the actual costs of the project, rather than the forecast costs as included in this Application.[595]

H. CONCLUSION ON CAPITAL EXPENDITURES

364. The FEU submit that it has demonstrated that its forecast capital expenditures are reasonable and required for the prudent continued operation of the system in order to provide reliable and safe service to customers.

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[592] Exhibit B-17, BCUC IR 2.41.2 and 2.42.1.

[593] Exhibit B-1, p. 383.The Commission granted a CPCN for the project by Order No. C-9-07, dated November 15, 2007.

[594] Please refer to Exhibit B-17, Attachment 41.1 in response to BCUC IR 2.41.1 (and the table provided in BCUC IR 2.42.1) which demonstrate that the total forecasted costs over the life of the project, currently embedded in rates, are equal to the CPCN approved amount.

[595] Exhibit B-17, BCUC IR 2.42.2.

PART NINE: DEFERRAL ACCOUNTS

A. INTRODUCTION

365. The FEU have provided a detailed explanation of existing deferral accounts it proposes to continue and new deferral accounts for the 2012 and 2013 test period. Only a small number of those accounts were probed by participants in the proceeding. In this Part we explain the financial treatment of deferral accounts and summarize the evidence supporting the deferral accounts explored during the proceeding that have not been addressed elsewhere in this Submission.[596]

B. FINANCIAL TREATMENT OF RATE BASE / NON-RATE BASE DEFERRAL ACCOUNTS

366. There are two types of deferral accounts – rate base and non-rate base. In the FEU's case, the majority of deferrals are rate base deferrals with the mid-year balance included in the rate base calculation for the utility.[597] The financial treatment associated with each type of account was discussed in depth in the response to BCOAPO IR 1.1.4.[598] Mr. Thomson explained the difference in the two types of accounts and how the treatment impacts customers in response to a question from the Commission Panel.[599] The return on rate base deferral accounts and the AFUDC rate are very similar.

367. The size and rate impact of the FEU's deferral accounts is relatively small. For instance, the FEI's total mid-year rate base deferral account balances are forecast to be approximately 1% of rate base in 2012 and the amortization expense of the deferral accounts is forecast to be less than 1% of the FEI's total revenue requirements.[600]

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[596] The Gains and Losses on Asset Disposition Deferral Account and the Customer Service Deferral Account are discussed above in *Part Six: Depreciation and Amortization* and *Part Five, Section E: Customer Service*, respectively. The EEC deferral accounts are discussed below in *Part Eleven: Energy Efficiency and Conservation*.

[597] Exhibit B-6, BCOAPO IR 1.1.3 and 1.1.4. Exhibit B-1, Appendix G includes a list of non-rate base deferrals.

[598] Exhibit B-6.

[599] Thomson: T5, p. 687, l. 1 to p. 688, l. 25.

[600] Exhibit B-9, BCUC IR 1.6.

C. GAS COST VARIANCE ACCOUNT (GCVA)

368. FEVI's GCVA was established effective January 1, 2003 by Commission Order No. G-2-03 to accumulate the variances between the actual and the forecast gas costs on a royalty adjusted basis, for amortization and recovery from, or refund to, sales customers in future rates. FEVI proposes that the differences between the actual and forecast gas costs continue to be accumulated in the GCVA for the two-year period, and that the December 31, 2013 balance be amortized through future rates.[601]

369. Questions in the proceeding focused on FEVI's proposal to cease quarterly reporting on the GCVA. Quarterly reporting of FEVI's forecast gas costs and GCVA balances is unnecessary as FEVI rates are proposed to remain frozen for the test period and will not be subject to quarterly gas cost flow through adjustments.[602] The FEU do not foresee a need for any mid-term rate increases, and opportunities exist for FEVI to apply to adjust rates if unforeseen circumstances occur.[603]

370. There will still be transparency during the test period as 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 are reported.[604] FEVI is not opposed to reporting on an annual basis. If the Commission were to require annual reporting, FEVI proposes that the 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. An alternative would be for FEVI to file quarterly reports that exclude reporting on

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[601] Exhibit B-1, pp. 390-391.

[602] Exhibit B-1, pp. 390-391; Exhibit B-9, BCUC IR 1.109.1 and Exhibit B-17, BCUC IR 2.69.1. Des Brisay: T4, p. 628, l. 15 to p. 630, l. 9.

[603] Exhibit B-17, BCUC IR 2.69.1. Should an unforeseen and sustained escalation in the market price of natural gas occur such that the overall GCVA and RSDA surplus were to be eroded, and at the same time the FEU amalgamation and rate harmonization is not successful effective January 1, 2013, then it may be necessary for FEVI to seek a mid-term rate increase in order to prevent an overall deficit at the end of 2013.

[604] Exhibit B-9, BCUC IR 1.109.1.

customer additions and the comparison to the competitive market, which are the components requiring the greatest amount of work to complete.[605]

D. COMPLIANCE WITH EMISSIONS DEFERRAL ACCOUNT

371. A deferral account is required for 2012 and 2013 incremental compliance costs and recoveries related to anticipated emissions trading regulations. The cap-and-trade regulations may apply to the FEU's operating emissions, requiring the FEU to comply with the requirements by purchasing allowances and offsets, or making internal reductions to meet targets. As Cap and Trade is yet to be legislated, the requested deferral account will capture costs and revenues to comply with the regulations when they come into effect.[606] These compliance costs and recoveries are difficult to forecast because of uncertainty around the final form and applicability of emissions trading regulations.[607]

372. Information requests centered on the process for tracking compliance costs and revenues. The process to track and record all costs and revenues related to emissions regulations 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, the FEU will create the necessary internal orders and accounts to capture the costs.[608] 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.[609]

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[605] Des Brisay: T4, p. 628, l. 15 to p. 630, l. 9.

[606] Exhibit B-9, BCUC IR 1.108.2.

[607] Exhibit B-1, pp. 396-397.

[608] Exhibit B-9, BCUC IR 1.108.1.

[609] Exhibit B-9, BCUC IR 1.108.2.

E. BIOMETHANE VARIANCE ACCOUNT

373. The Biomethane Variance Account ("BVA") was one of three deferral accounts created by Commission Decision and Order No. G-194-10, dated December 14, 2010, regarding the FEU's Biomethane Application.[610] The BVA captures costs to procure and process consumable biomethane gas as well as revenues collected through the biomethane energy recovery component of rates. The BVA captures biomethane commodity costs, the capital cost of service of the upgrader plant, O&M associated with the upgrader plant and O&M costs attributable to biomethane customer enrolment, account finalization and billing adjustments. The balance in the BVA is recovered through the Biomethane Energy Recovery Charge.[611] The only change to the BVA that FEI is requesting is to treat the BVA as a non-rate base deferral.[612]

374. In this case, a rate base deferral account recovers the costs from natural gas customers, and a non-rate base deferral account would only recover the cost from targeted customers.[613] Treating the BVA as a non-rate base account 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.[614]

375. Ms. Roy also explained other benefits of making the BVA a non-rate base deferral account:[615]

> So we've requested it to be non-rate base, and the reason for that is simply that upon further review of the account there's really two reasons why you might want it to be non-rate base. One is to keep the costs -- be able to stream those

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[610] Exhibit B-9, BCUC IR 1.110.1.

[611] Exhibit B-1, Appendix G, p. 1 and Appendix J, p. 1. Exhibit B-9, BCUC IR 1.110.1.

[612] FEI, however, 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. (See Exhibit B-1, Appendix J, p. Table J-4.)

[613] Roy: T4, p. 602, l. 21 to p. 603, l. 2.

[614] Exhibit B-9, BCUC IR 1.185.1. 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.

[615] Roy: T4, p. 601, l. 18 to p. 602, l. 1

> costs more easily to future biomethane customers because this account is just to the account of the biomethane customers. And also that included in that account was there was an actual rate base return, and we didn't want to be double counting on that.

376. Thus, the FEU submit that it most appropriate to treat the BVA as a non-rate base deferral account for 2012-2013.

F. BIOMETHANE PROGRAM COSTS

377. In addition to the BVA, Commission Decision and Order No. G-194-10, dated December 14, 2010 created two other Biomethane deferral accounts:[616]

- 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
- Biomethane Program Costs - O&M: this account captures the operating and maintenance costs incurred in 2010 and 2011 applicable to all customers, attracting AFUDC.

378. Pursuant to the Commission approved treatment, the costs accumulated in these accounts are being transferred to rate base and amortized through delivery rates over a three-year period beginning January 1, 2012. All of the Biomethane Program Costs are detailed in Table J-5 of the Biomethane Report and include Other Revenue of $90,100, cumulative 2010 and 2011 O&M of $616 thousand (net-of-tax) and Biomethane Application costs of $191 thousand (net-of-tax).[617] Further information on these costs is provided in Exhibit B-9, BCUC IR 1.183.1 to 1.183.3, 1.186.1 to 1.186.6, 1.188.1 and Attachment 188.1, p. 3. Biomethane education costs were considered in Part five, Section D(d) of these Submissions.

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[616] See Exhibit B-1, Appendix J, p. 1; Exhibit B-9, BCUC IR 1.110.1.

[617] Exhibit B-9, BCUC IR 1.110.4. 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. (BCUC IR 1.186.3.

G. CNG AND LNG RECOVERIES

379. Commission Order G-128-11 approved an "ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act." FEI are seeking to expand this account to capture the following:

- Any variations from the total forecast LNG fueling station revenues, rather than just the revenues in excess of the minimum contract demand related revenues;[618]
- Any variation from the forecast of Rate Schedule 16 revenues of $1.1 million in each of 2012 and 2013,[619] whether NGV or non-NGV customers;[620] and
- Any variance from the forecast LNG tanker revenue, whether NGV or non-NGV customers.[621]

380. FEI is not proposing to include any costs in the deferral account. The fueling station rate is set to recover the service costs of the asset based on the minimum contract demand. The FEI has no plans to expand the Tilbury facility or purchase additional tankers in 2012 and 2013.[622]

381. The proposed expansion of the deferral account will give customers the benefit of any revenues not forecast for the new CNG and LNG service. Rate Schedule 16 is a relatively new rate schedule and the only customer currently forecast to generate revenues under this

[618] Exhibit B-9, BCUC IR 1.112.1 and 1.112.2; Exhibit B-51.

[619] Roy: T4, p. 612, ll. 2-3; Exhibit B-1-3, revised p. 14 of the Application.

[620] Exhibit B-9, BCUC IR 1.112.1; Exhibit B-17, BCUC IR 2.87.1 and 2.87.2. The FEU presently have no non-NGV Rate 16 customers and it is unlikely that any non-NGV Rate 16 revenues would be recovered in 2012-2013.

[621] Exhibit B-51, Undertaking No. 23; Thomson: T4, p. 615, ll. 16 to 26. As noted in Exhibit B-51, the revenues from the transportation of LNG from Tilbury to the Vedder Transport fueling station are included in the Application and embedded in the LNG fueling station revenue forecast.

[622] Roy: T4, p. 616, l. 1 to p. 618, l. 2.

Rate Schedule is Vedder Transportation.[623] There are a number of factors that could cause variations in the forecast, including FEI's ability to negotiate and sign service agreements with new LNG customers, and add incremental load to existing customers.[624] A variation in LNG agreements like the agreement with Vedder Transport could have a significant impact on the volume and revenue forecast.[625] Absent an expansion of the deferral account, any revenues that FEI was successful in generating would flow to the shareholder.[626]

382. Given that any additional revenues are subject to factors beyond the control of the FEU and cannot be forecast at this time, a deferral account for the Rate Schedule 16 revenues is appropriate and in the interests of customers.[627]

H. GAS ASSETS RECORDS

383. The FEU submit that it is appropriate and in the interest of customers to establish a new deferral account to capture variances from forecast costs on the FEU's Gas Asset Records Project. The project is planned to be carried out in three phases over a four-year period (2012 to 2015) and the FEU propose that the costs in each year be amortized over a 5 year period.[628]

384. As explained in detail in the Application, the Gas Asset Record Project is designed to improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records and the retention and disposal of compliance records no longer needed.[629] The need for the project is driven by directives from the Oil and Gas Commission and amendments to the bylaws of the Association

[623] Exhibit B-1, p. 399, as updated by Exhibit B-1-3.
[624] Exhibit B-9. BCUC IR 1.112.3.
[625] Exhibit B-9, BCUC IR 1.112.5.
[626] Thomson: T4, p. 612, ll. 20 to 23.
[627] Exhibit B-9, BCUC IR 1.113.1.
[628] Exhibit B-1, pp. 411-415.
[629] Exhibit B-1, pp. 411-415. The benefits of the project and cost savings are also discussed in Exhibit B-9, BCUC IR 1.118.4.

of Professional Engineers of B.C. that have come in the wake of the San Bruno gas pipeline explosion in September 2010.[630]

385. There are two rationales for the deferral account:

- 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. The forecast costs are difficult to anticipate due to the unpredictable state of the documents and the varying effort needed to interpret historical drawings and gas system asset records from multiple companies, locations, and record keeping systems.[631]

- The use of the deferral account will allow the FEU to spread the costs out over a longer period better matching the period over which the benefits of the project will be realized.[632] An amortization period of five years results in costs being spread 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.[633]

I. BC ONE CALL

386. The FEU are also requesting a deferral account to capture variances from the forecast costs to complete the BC One Call Ticket Process Improvement Project. This project is described in detail in the Application at pages 415 and 418. Further information is provided in response to BCUC IR 1.119.1 to 1.119.3. Once complete, the project is anticipated to provide

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[630] Exhibit B-1, pp. 411 to 413.

[631] Exhibit B-9, BCUC IR 1.118.5.

[632] Exhibit B-1, p. 413.

[633] Exhibit B-9, BCUC IR 1.118.6.

annual cost savings of approximately $540 thousand.[634] The use of a deferral account with a five-year amortization period will permit the FEU to spread the costs out over a longer period, better matching the period over which the benefits of the project will be realized.

J. CONCLUSION ON DEFERRAL ACCOUNTS

387. The FEU submit that its deferral accounts are appropriate and in the interest of ratepayers and should be approved as filed.

[634] Exhibit B-9, BCUC IR 1.119.3.

PART TEN: RATE BASE – ISSUES RAISED

A. INTRODUCTION

388. The determination of rate base is a step in the calculation of the revenue requirement, as it forms the basis for the earned return component of the cost of service. The components of rate base are described in depth in Chapter 6 of the Application. During the proceeding, the focus of the rate base discussion centered on a few issues, which are the subject of this Part:

- The FEU's investment in the Olympic cauldron;
- Underperforming Main Extensions (MX); and
- The FEU's purchase of an LNG road tanker and mobile LNG fueling station.

Participants (primarily Commission Staff) advanced various arguments to warrant the exclusion of these items from the calculation of rate base. The FEU submit that these items represent prudent investments for the benefit of customers and are appropriately included in rate base.

B. OLYMPIC CAULDRON

389. The FEU's investment in the Olympic cauldron was prompted by a once in a lifetime opportunity to participate in an important community event that had significance for most British Columbians. The FEU submit that customers continue to benefit from the investment in the cauldron.

(a) FEI's Investment and Associated Rate Impact

390. FEI invested $3.2 million in the Olympic cauldron. In its agreement with BC Pavilion Corporation (PavCo), FEI has a license to permit the Cauldron to remain in Jack Poole Plaza for 20 years with renewal rights for an additional 40 years. The ongoing operating and maintenance costs of the Olympic Cauldron are covered by PavCo.[635]

[635] Exhibit B-9, BCUC IR 1.5.2; Exhibit B-9-1, Attachment 5.2.

391. The Olympic cauldron is recorded in asset class 48600 in the Uniform System of Accounts, which is tools and equipment, with a depreciation rate of 5%.[636] As a rate base asset, the investment in the cauldron affects the debt financing and earned return components of cost of service.[637] This treatment has been accepted by the FEU's auditors.[638]

392. The Olympic cauldron had no impact on rates in 2009, 2010 or 2011. Starting with 2012, the 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.[639] The revenue requirement impacts in 2012 and 2013 associated with the cauldron is $350,000, reflecting the rate base return and depreciation expense of approximately $225,000.[640] The delivery rate impact is approximately 0.06 percent.[641]

(b) Investment Was a Prudent Expenditure for the Benefit of Customers

393. The cauldron is a unique asset. It was not built as a result of its value as a main extension, but rather the more difficult to quantify – but still very real – benefits associated with good corporate citizenship and facilitate the efficient delivery the FEU's services and ongoing operations. In its letter to the Commission advising of the acquisition of the cauldron, the FEU wrote:[642]

> Customers will benefit from the Company's involvement in preserving the Olympic legacy. British Columbians have embraced the Olympics with the torch run attracting large, enthusiastic crowds in Vancouver and many other communities in British Columbia. The permanent cauldron, funded by Terasen Gas, has been a focal point of activity and celebration during the Olympics. TGI does business in the BC communities touched by the "Olympic spirit". We rely on good relationships with these communities to facilitate work on the utility infrastructure. Our investment in maintaining and enhancing these relationships

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[636] Exhibit B-17, BCUC IR 2.3.1.

[637] Thomson: T4, p. 500, ll. 16-23.

[638] Exhibit B-17, BCUC IR 2.3.1.

[639] Exhibit B-9, BCUC IR 1.5.2.

[640] Thomson and Roy: T4, p. 501, ll. 5-17.

[641] Exhibit B-9, BCUC IR 1.5.2.

[642] Exhibit B-9-1, Attachment 5.2.

> assist us in completing projects on time and on budget, and ultimately in delivering energy service in an efficient and cost-effective manner.

394. Mr. Walker spoke of the importance of this community investment from the perspective of being a good corporate citizen:

> If I could, basically from the point of view, again I go back to the contributions and in being involved in the community and the types of contributions. This particular project is a very unique, probably one-time opportunity, I don't know if in a lifetime, but certainly for a very long time. And in our business today in the utility business, it's very important that we develop relationships in terms of how we're perceived in the communities at the municipal level, the provincial level, and broader with our customers. And this kind of element, while different and substantial, more unique than probably would have done in the past or in the normal line of things, is part of that whole report. We have to put facilities that are often controversial or they require support or developing those relationships and buying into it. So I believe that this contributes to that economic outcome in the broader sense.

395. Mr. Thomson similarly stated that the investment was made "for the purposes of being involved in a once-in-a-lifetime event for the people of British Columbia and Canada".[643] The benefits associated with strong corporate citizenship are discussed in Part 4, Section G of this Submission. Mr. Thomson also cited the positive impact the association with the cauldron had on morale, which ultimately benefits customers.[644]

396. While the shareholder earns a return on capital it has invested in the cauldron (as it does with any invested capital in the utility), the reputational impacts associated with good corporate citizenship flow to customers of the operating utilities. They will continue to flow to customers over the life of this legacy investment.

[643] Thomson: T3, p. 453, ll. 22-26.

[644] Thomson: T3, p.454, ll. 13-16: "I know that it was certainly a great source of pride for the company and its employees, being associated with that."

(c) Cauldron is "Used and Useful"

397. The Olympic cauldron is a "used and useful" rate base asset. The Cauldron continues to be used for community events and symbolic purposes[645] and consumes gas, which puts load on the system and generates revenues that benefit of all customers.[646] PavCo is a natural gas customer under Rate Schedule 2 and takes service when the cauldron is lit.[647] More importantly, the cauldron is also "used and useful" in the sense that it represents the Companies' important community investment with a lasting legacy.[648] While the asset is "used and useful", the relevant inquiry is primarily one of prudence and the benefits of this unique investment have been established above.

(d) Retail Markets Downstream of the Meter

398. The Commission's Retail Markets Downstream of the Meter Guidelines were raised during the oral hearing in the context of the cauldron.[649] The guidelines state:[650] "The Commission has jurisdiction to prohibit a public utility from participating in retail markets downstream of the meter if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers." The Olympic cauldron is a unique asset designed and created for the 2010 Olympics and Paralympics in Vancouver, for which there is no retail market. As Mr. Stout observed, the guidelines are more applicable to the utility participating in retail activities such as furnace repair and H-Vac repair and those types of activities.[651] The FEU submit that the Commission's Retail Market Downstream of the Meter guidelines are inapplicable to a unique asset like the Olympic cauldron.

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[645] Thomson: T4, p. 500, ll. 9-11.
[646] Exhibit B-17, BCUC IR 2.3.1.
[647] Thomson: T4, 502, ll. 16-19.
[648] Exhibit B-17, BCUC IR 2.3.1.
[649] Stout: T5, p. 862, ll. 3 to 25.
[650] See Exhibit A2-4.
[651] Stout: T5, p. 862, l. 26 to p. 863, l. 5.

(e) Conclusion on Olympic Cauldron

399. The FEU submit that the Olympic cauldron continues to provide benefits to customers and, as such, the investment in the cauldron should be recovered from customers.

C. MAIN EXTENSIONS

400. The Companies install over 300 main extensions per year in accordance with the Commission-approved main extension test (the "MX Test"),[652] which has as its central purpose balancing the desirability of making service available to new customers while seeking to ensure that, on the whole, existing customers are not unfairly burdened by the extensions. FEU's main extensions, considered as a portfolio, achieve this purpose.

401. Commission Staff singled out three main extensions – Sooke, West Coast Road and Shawnigan Lake - that have underperformed against original expectation in their initial few years following completion, due to costs being higher than forecast and/or attachment rates being below forecast. Staff withdrew questions regarding Sooke based on the objection of counsel for FEU.[653] As such, this Submission will only address Shawnigan Lake and West Coast Road. The FEU submit that Shawnigan Lake and West Coast Road, while underperforming currently, are "used and useful" and were prudent. They must be included in rate base.

(a) Shawnigan Lake and West Coast Road Extensions Were Prudent Investments

402. While the Shawnigan Lake extension has cost more than originally estimated and to date both extensions have yielded below forecast additions,[654] the decision that must pass the prudence test is the decision made by FEVI to proceed with the extensions. These

[652] Order No. G-152-07.

[653] The objection to questions on Sooke was, in essence, based on relevance, since the Commission had already determined the issue. The Sooke extension was the product of a CPCN in 2004, not the application of the MX Test. It had already been subject to a prudence review, and the Commission had reconfirmed the FEVI cost of service based on the allowed costs of that extension every year since then. The submissions of counsel for FEU are found at T4, p. 514, l. 13 to p. 519 l. 11.

[654] Both the Shawnigan Lake and West Coast Road extensions were completed in 2009. Shawnigan Lake cost $1.2 million more than originally estimated, and as of May 31, 2011, 88 of 193 forecasted attachments have materialized. No customers have attached to the West Coast Road extension as of May 31, 2011, which cost $139,393 more than originally estimated. Exhibit B-9-1, Electronic Attachment 100.1.

extensions meet the prudence test because FEVI's decision to undertake the extensions was based on the outcome of the Commission-approved MX Test and using information available at the time.

MX Test Outlines How Prudent Decisions Are To Be Made

403. Order No. G-152-07 dated December 6, 2007, regarding the FEI-FEVI (then TGI-TGVI) System Extension and Customer Connection Policies Review, approved the objectives of the MX Test to promote fair and equitable treatment of customers, to avoid undue discrimination and to ensure that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of that year. The individual threshold PI of 0.8 was approved by the Commission for individual main extensions, along with an aggregate PI of 1.1. The targeted aggregate PI of 1.1 was chosen because it was more conservative than requiring a PI of 1.0 and therefore able to accommodate unanticipated variances in either cost or consumption that may occur. Even if a main extension hypothetically has a PI value less than 0.8 at the end of the five year period, it is the aggregate threshold that demonstrates whether the existing customers received a benefit from the attachment of new customers on an aggregate basis. An aggregate PI of 1.1 ensures that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of that year.[655]

404. Before proceeding with the Shawnigan Lake and West Coast Road extensions in the FEVI service area, FEVI applied and met the approved MX Test approved by the Commission. From 2008-2011, FEVI followed the approved process that if any individual MX Test resulted in a PI of less than 0.8, the main extension 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 main extension. Furthermore, the Companies ensured that the targeted aggregate PI for both utilities was at least 1.1.[656] The FEU submit that proceeding with

[655] Exhibit B-17, BCUC IR 2.65.1.
[656] Exhibit B-17, BCUC IR 2.65.1.

the extensions based on the results of the MX Test was prudent and, indeed, consistent with the terms of the Commission-approved policy.

No Hindsight

405. The test of prudence is whether that decision was reasonable at the time based on the circumstances which were known, or reasonably should have been known, when the decision was made.[657] The inputs in the approved MX Test were, at a high level, costs of the extension and forecast demand. The issues that have arisen with the assumptions used in the application of the MX Test for West Coast Road and Shawnigan Lake are only apparent with the benefit of hindsight.

406. On the forecast demand side, the economic downturn that stalled development of these two subdivisions could not be foreseen. Emerging facts cannot be a basis for a prudence assessment, as the prudence test determined by the courts and adopted by this Commission involves an assessment based on the facts as they existed at the time the decision was made.[658] The test expressly precludes assessments based on hindsight.

407. Costing information was determined using the Commission-approved geo-code methodology. The geo-code methodology uses average costs to enable efficient costing of main extensions. As a result of reviewing the Shawnigan Lake main extension and the cost estimating process, the FEU have since recognized that for a small number of main extensions that share common characteristics with the Shawnigan Lake extension, a manual cost estimating methodology is more appropriate to reflect site specific requirements which are not sufficiently reflected in a geo-code.[659] FEI and FEVI noted in their 2010 Year End MX Reports

[657] Decision, *In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements*, March 13, 2009 (BCUC Order No. G-16-09), at pp. 31 to 39; *Enbridge Gas Distribution Inc. v. Ontario (Energy Board*), [2006] O.J. No. 1355; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122. See Appendix B: Book of Authorities, Tabs 2, 3 and 4.

[658] Decision, *In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements*, March 13, 2009 (BCUC Order No. G-16-09), at pp. 31 to 39; *Enbridge Gas Distribution Inc. v. Ontario (Energy Board*), [2006] O.J. No. 1355; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122. See Appendix B: Book of Authorities, Tabs 2, 3 and 4.

[659] Exhibit B-9, BCUC IR 1.99.2 and 1.100.2.

submitted to the Commission on June 1, 2011, that while geo-code pricing works well for the vast majority of extensions, the geo-code pricing methodology is not the best estimating method for approximately 10% of main extensions due to unique site specific requirements.[660] The FEU have fixed this issue by implementing a manual estimating process for main extensions for which the geo-code methodology is not ideal. This change is expected to reduce the variances between the actual and estimated cost for these certain types of main extensions.[661]

408. While the FEU know now that in approximately 10% of cases a manual cost estimate should be used, at the time the decision was made to proceed with the Shawnigan Lake or West Coast Road main extensions the expectation was that the FEU should be applying the accepted geo-code methodology. At the time, the geo-code methodology appeared to be a reasonable and cost-effective approach.[662]

409. The FEU therefore submit that the expenditures for the Shawnigan Lake and West Coast Road main extensions were prudently incurred.

(b) Shawnigan Lake and West Coast Road Extensions Are Used and Useful

410. The FEU submit that the Shawnigan Lake and West Coast Road main extensions are also used and useful because Shawnigan Lake is in use and West Coast Road is complete and will be in use in the near future.

411. Both the Shawnigan Lake and West Coast Road main extensions were completed a little over two years ago in 2009.[663] Mr. Dall'Antonia explained the circumstances with Shawnigan Lake and West Coast Road as follows:[664]

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[660] Exhibit B-9, BCUC IR 1.99.2.

[661] Exhibit B-9, BCUC IR 1.100.2.

[662] Decision, *In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements*, March 13, 2009 (BCUC Order No. G-16-09), at pp. 31 to 39; *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122. See Appendix B: Book of Authorities, Tabs 2, 3 and 4.

[663] Exhibit B-9-1, Electronic Attachment 100.1.

[664] Dall'Antonia: T4, p. 510, l. 20 to p. 511, l. 18.

> At this point in time the attachments are less than the forecast, but these mains will have a useful life that far exceeds the two years since they've been put in place. These mains are ready to be used, and in the case of Shawnigan Lake are being used to provide service.
>
> My understanding of what's occurred with these two mains is that the developer planned very large subdivisions on Vancouver Island in 2008. The services were put in place. There was an economic downturn. The developments have been, in the case of Shawnigan Lake, split into two phases. The first phase is, I think, sold out. The second phase is, we expect, will be -- will go forward. In West Coast Road a similar situation, there is a subdivision with curbs, roads, services, water service, electric service, gas service ready to go. So the system is ready to be used and we fully expect that it will be used. This came into service 2009, mid-2009, so just over two years ago, so we do expect that over life it'll be used.

412. As Mr. Dall'Antonia stated, the Shawnigan Lake extension is being actively used for providing service, it should be considered "used and useful" regardless of the current experience of customer attachments.

413. In the context of new main extensions being put into service, it is the physical capacity to provide service and the reasonable expectation that customers will be connected to it in the near term that should be the measure for "used and useful", not the flow of gas at a given point of time. Since utilities are installed in a subdivision before houses are constructed, there will commonly be a lag between the time the extension is complete and when the first houses in the subdivision are complete and taking natural gas service. Pending the completion of the subdivision, the pre-installed facilities are being used and are useful for the purpose of permitting connections to occur when the houses are complete. West Coast Road is a situation where the economic conditions caused the developer to delay the construction of the houses in the subdivision after services (including, but not limited to natural gas) were installed; however, the principle remains the same. The West Coast Road extension is available to be used to provide service when the development is completed. The developer's investment in roads, curbs and services in the subdivisions is sunk, and it is reasonable to expect that either the original developer or a new one will take advantage of that investment when the economic conditions prove more favourable.

414. Commission counsel, in cross examination, introduced a passage from a text to Mr. Walker which included the following statement on the used and useful test:[665]

> For decades, used and useful referred to needed capacity; that is, a determination as to whether a plant was actually used in service and was useful in providing service. If not, or if any expenditures were imprudent, all or part of the investment in a plant would be excluded from rate base. Today, however, used and useful has been held by some commission to be a broader concept. The Massachusetts commission, to cite one example, holds that under the used and useful standard it must "determine whether a utility investment is needed and *economically desirable*." . . .

415. Commission counsel referred specifically to the "broader concept" used by the Massachusetts commission that is referenced at the end of the quote above. There are several points in response to the apparent suggestion that the Commission should be considering whether assets are "economically desirable" as part of the used and useful test.

416. First, the text itself identifies that the "broader concept" as an alternative approach taken by some Commissions, and it is contrasted to the traditional concept that has been used "for decades." The text does not endorse the broader approach.

417. Second, it is also necessary to consider the context of the analysis. The economic analysis implied by the referenced test employed by the Massachusetts commission was conducted based on a large single asset ("a new electric utility production plant"). There is a distinct difference between the assessment of the economic viability of a single utility asset (such as a nuclear facility) and parsing an integrated system at a point in time to single out portions of it that are underutilized, while ignoring the fact that other aspects of the system are over utilized. That approach is inconsistent with the rationale for the MX Test, which targets an aggregate profitability index. The FEU submit that provided the assets are physically "used and useful", as these extension assets are, it is necessary to accept varying degrees of system utilization in various locations at different points in time.

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[665] Exhibit A2-2, p. 76. Phillips, Jr., Charles F., *The Regulation of Public Utilities: Theory and Practice*, (Arlington, Virginia: Public Utilities Reports, 1988).

418. Third, the “used and useful” test is a distinct test from the assessment of prudence, but they must be applied harmoniously. In order to remain analytically consistent with the accepted prudence test, the “used and useful” as applied to distribution assets must focus on the use and usefulness of the assets in the provision of utility service, and not an *ex post* assessment of the economics of the investment.

419. Fourth, to exclude underperforming main extensions from rate base based on underutilization in the early years of an extension is at odds with the design of the MX Test, which uses a twenty-year discounted cash flow model and contemplates a portfolio review of extensions performed in a given year. There is no basis to justify selectively looking at individual main extensions that are below the portfolio average without also recognizing that there are necessarily extensions that are above average to keep the portfolio above the required portfolio Profitability Index.[666] Mr. Thomson explained:

> And the MX test is a test, as had been outlined in the information request response that Mr. Fulton referred to, as a means to look at whether the overall system attachments in a year would be detrimental or favourable to the existing customers. We don't carve them up one by one, because to do so -- by its very design, the profitability index on an individual main needs to meet a threshold of .08 [sic - 0.8]. That means in isolation that that individual main that only met the .08 [sic – 0.8] would not be profitable over time. So the test is designed to allow attachments to the system as a whole in a given year, and that's why the PI of 1.1 that's used for the whole portfolio was agreed upon. The five-year review element is to assess whether that approach to looking at main extensions still makes sense going forward.[667]

Removing underperforming main extensions would be akin to receiving a premium for over performing economic main extensions (e.g. PI>1.0), which also contradicts the rationale for having an aggregate threshold. Order G-152-07 treats all main extensions equally with no special treatment for either over- or under-performing main extensions.[668]

[666] Thomson: T4, p. 512, l. 12 to 513, l. 18.

[667] Thomson: T4, p. 512, l. 12 to p. 513, l. 18.

[668] Exhibit B-17, BCUC IR 2.65.1.

420. Fifth, even assuming the Commission was to determine whether an asset can be excluded from rate base based on the economic performance of the extensions, it is too soon to know whether these extensions are economic. While the costs of the extensions are known, the associated revenues they will generate over time are not known. These assets have a long service life, and have only been in service for a little more than 2 years. A main extension will almost never have generated sufficient revenue in its first two years to recover the cost of the assets used to provide service. Therefore, examining the economics of these extensions now is not appropriate. Mr. Thomson indicated that the Company fully expects the costs to be recovered over time.[669]

421. Sixth, the MX Test contemplates using the forecast of only the first five years of attachments in determining the PI, and this fact was raised in the context of Staff IRs and cross examination by Commission counsel in the context of discussing a review of the performance of the West Coast Road and Shawnigan Lake main extensions after five years.[670] However, under the Commission-approved framework the five-year period in the MX Test is only relevant in determining the reconciliation and potential refunds associated with a contribution in aid of construction provided by a customer. The five-year period was not intended to be identifying the point in time after which installed main extensions must compare favourably to the original forecasts to remain in rate base.

422. If the Commission were to begin parsing public utility systems to remove from rate base discrete elements of an integrated utility system based on "underperformance" or "underutilization" at a point in time, this would add a new element of risk to the FEU's operations that was not previously contemplated under the regulatory framework in British Columbia as reflected in the Commission's MX Text.

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[669] Thomson: T4, p. 512, ll. 6-11.

[670] Dall'Antonia: T4, p. 511, ll. 19-512, l. 1.

(c) "Used and Useful" is Different From Asset Impairment

423. Asset impairment is the test used by the Companies for financial purposes to determine whether or not assets should be written off. The line of question from Staff and Commission counsel regarding the need to assess the West Coast Road and Shawnigan Lake main extensions for asset impairment[671] appears to presume incorrectly that the test for asset impairment informs the "used and useful" test. In fact, the concept of asset impairment only comes into play once the assets have been excluded from rate base, whether by virtue of a determination that the assets are either no longer "used and useful" or that the investment in those assets was imprudent. So long as an asset remains in rate base, there is an expectation that the capital invested will be recovered (i.e. return of capital) through delivery rates that are set to include depreciation expense. This is consistent with the regulatory compact that is reflected in the rate setting provisions of the UCA. Mr. Thomson confirmed that the status of these two particular main extensions accords with the asset impairment policy, and no write off is required for financial purposes. The test for impairment is whether revenues over the life of the asset will recover the cost, and in the case of these extensions "That's fully our expectation."[672]

(d) Conclusion on Main Extensions

424. The FEU submit that its main extensions, including the Shawnigan Lake and West Coast Road main extensions, represent prudent expenditures in accordance with the MX Test and are used and useful for providing utility service to customers. Further, the FEU submit that it would be inequitable and inconsistent with the MX Test to exclude from rate base certain main extensions that underperform.

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[671] Commission counsel asked Mr. Dall'Antonia about reviewing for impairment after five years: T4, p. 511, l. 19 to p. 512, l. 1. The five years is a reference to the period after which the Commission will revisit the MX test itself. As discussed above, the review has nothing to do with assessing the prudence or impairment of particular assets.

[672] Thomson: T4, p. 512, ll. 6-11.

D. LNG Tankers and LNG Mobile Fueling Station

425. The Commission issued a supplemental set of IRs related to FEI's LNG Tankers and the LNG Mobile Fueling Station. The general thrust of the IRs was to question whether FEI's new LNG tanker and LNG Mobile Fueling Station are appropriately in rate base. The responses to those requests explain in detail why these assets are used and useful and appropriately in rate base. In summary:

- The FEU purchased a second LNG road tanker in December 2010 as a backup to an older tanker which was purchased in 1996. The new tanker is required as a backup under FEI's Emergency Response Plan registered with Transport Canada for LNG transport. The new LNG tanker is a valuable backup resource for system reliability and integrity in both planned and unplanned (emergency) outages and the design of the new tanker offers increased flexibility and capacity in use compared to the older tanker in FEI's possession. The revenue from use of the tanker for LNG transport service to customers such as Vedder Transport will be used to offset the cost of service of the asset.[673] In short, although the asset sits idle sometimes, the tanker is in full time use as a component of the Emergency Response Plan.

- FEI purchased a mobile LNG station known as IMC 6000 in December 2010. The IMC 6000 unit will be used by Vedder starting in early October of 2011. Vedder will continue fueling with the IMC 6000 unit until their minimum quantity commitment of 57,500 GJ is reached and the permanent fueling station is commissioned.[674] The asset can be used for a number of other purposes after Vedder's permanent station is commissioned, including use at another NGV customer's site as a permanent solution or a backup system resource to fuel existing gas customers.[675] The IMC 6000 unit could also be used in support of

[673] Exhibit B-22, BCUC Supplemental IR 1.1 and 1.10.

[674] Exhibit B-17, BCUC IR 2.135.1; Exhibit B-22, BCUC Supplemental IR 2.1.

[675] Exhibit B-17, BCUC IR 2.135.1.

the development of a satellite LNG to CNG natural gas distribution system or as a means to store LNG for a remote community's power generation system. FEI is investigating these potential markets and early assessments indicate that both have attractive business cases. The IMC 6000 unit could also be sold for service in NGV operations in other jurisdictions.[676] As an asset that will be actually used in the test period and provides operational flexibility, the IMC 6000 is used and useful.

426. The FEU note that there were no questions on the LNG tankers or the LNG fueling station at the oral hearing. The FEU submit that these assets are properly included in rate base.

E. CONCLUSION ON RATE BASE ISSUES RAISED

427. The FEU submit that costs related to the Olympic Cauldron, main extensions, and the LNG tankers and mobile LNG station are all appropriately included in rate base.

[676] Exhibit B-22, BCUC Supplemental IR 2.5.

PART ELEVEN: ENERGY EFFICIENCY AND CONSERVATION

A. INTRODUCTION

428. The FEU have been working since 2008 to develop a broad portfolio of EEC measures that address the expectations of customers interested in energy efficiency and conservation as well as meeting the requirements for public utilities to pursue cost effective demand-side measures as a component of resource planning. The first significant step forward was the approval of funding in the 2008 EEC Application for 2008, 2009 and 2010. The FEU continued to build on that portfolio in 2010 and 2011 based on the approvals granted in the 2010-2011 RRAs for FEI and FEVI. The FEU's existing EEC programs have been described in detail in its EEC Annual Reports[677] and the portfolio is cost-effective under the Total Resource Cost (TRC) test. The evidence demonstrates that the FEU have come a long way in retaining qualified staff, developing cost effective programs, and delivering incentives to many customers, but the initial expectations that the FEU and stakeholders had about the amount of incentives provided to customers to this point have not been achieved.

429. The Companies' EEC-related requests in this 2012-2013 RRA are a response to the current state of progress, and reflect the Companies' expectations that there will be continued development over the test period. In particular, the FEU's proposed EEC portfolio provides funding to extend the existing Program Areas to all rate classes and service areas and to take advantage of the significant potential for cost-effective energy conservation as set out in the Conservation Potential Review. It also introduces the potential for new Program Areas that could be pursued if the cost-effectiveness test changes. At the same time, the FEU's proposed financial treatment of EEC spending is designed to ensure that the 2012-2013 rates reflect a reasonable estimate of activity to be undertaken, but do not reflect any amount that cannot be spent in the test period. The FEU submit that the financial treatment is appropriate and that its proposed expenditure schedules are in the public interest.

430. Part Eleven of these submissions addresses the following:

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[677] Exhibit B-1, Appendices K-3 and K-4.

- The legal framework for the acceptance of EEC expenditures;
- The best approach to assessing cost-effectiveness;
- How FEU's proposed financial treatment helps to ensure that rates only include amounts spent during the test period;
- The evidence supporting the proposed funding levels for existing Program Areas;
- Program-specific issues raised by participants;
- The merits of the New Program Areas; and
- The FEU's proposed accountability mechanisms and the importance of balancing flexibility and oversight.

B. THE LEGAL FRAMEWORK GOVERNING EEC EXPENDITURES

431. Section 44.2(2) of the UCA provides that the Commission must accept an expenditure schedule of "demand-side measure" expenditures before including those expenditures in rates. In this section, we address what qualifies as a "demand-side measure", and how the Commission must assess "demand-side measures" under section 44.2 of the UCA and the *Demand-Side Measures Regulation* (the "DSM Regulation").

(a) EEC Programs Are "Demand-Side Measures"

432. Section 44.2(a) applies to expenditures schedules for demand-side measures as defined in the *Clean Energy Act*. That definition is as follows:

> "demand-side measure" means a rate, measure, action or program undertaken
>
> (a) to conserve energy or promote energy efficiency,
>
> (b) to reduce the energy demand a public utility must serve, or
>
> (c) to shift the use of energy to periods of lower demand,
>
> but does not include

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

(e) any rate, measure, action or program prescribed;

433. The FEU's updated EEC portfolio only contains programs that either conserve energy, promote energy efficiency, or reduce the energy demand that the FEU must serve.[678] That includes the FEU's existing fuel-switching program area, and the proposed Thermal Energy for Schools and Solar Thermal Program Areas, each of which was queried in information requests. In particular:

- The High-Carbon Fuel Switching Program Area[679]: In the vast majority of cases, the oil- or propane- burning equipment is old and inefficient, and in all cases, is being replaced with an Energy Star furnace or boiler, thus increasing the efficiency of the equipment and significantly reducing GHG's in the process.[680] Fuel-switching programs are recognized in the California Standard Practice Manual, along with California's Energy Efficiency Policy Manual, as being a demand-side management category or program.[681]

- The Thermal Energy for Schools and Solar Thermal programs provide incentives for the use of highly efficient solar and thermal energy sources.[682] These programs therefore conserve energy and promote energy efficiency.

[678] The updated portfolio no longer includes $10 million of incentives for Natural Gas Vehicles as the Commission concluded that they are not "demand-side measures" within this definition.

[679] The FEU's fuel-switching programs are some of the FEU's longest running programs and promote the switching from burning of heating oil and propane to natural gas for home heating purposes. They were approved by the Commission in the EEC Application Decision.

[680] Also see Exhibit B-9, BCUC IR 1.194.2.

[681] Exhibit B-25, pp. 6 to 7. Appendix 2 to Exhibit B-25 is the California Standard Practice Manual.

[682] Exhibit B-1, Appendix K-1, pp. 13 to 15.

(b) Required Considerations for "Demand-Side Measures"

434. In considering whether a DSM expenditure schedule put forward by a non-crown public utility is in the public interest under section 44.2 of the UCA, the Commission must consider the following criteria:

- the applicable of British Columbia's energy objectives,
- the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
- the interests of persons in British Columbia who receive or may receive service from the public utility.

Each of these required considerations will be discussed below.

British Columbia's Energy Objectives

435. British Columbia's energy objectives are defined and set out in section 2 of the *Clean Energy Act*. The applicable energy objectives and how the FEU's proposals support those objectives are set out in the table below.

Energy Objective	FEU EEC Portfolio
(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;	The FEU's EEC proposals are designed to implement all cost-effective demand-side measures in the Province. The estimated net annual natural gas savings from the FEU's existing Program Areas is approximately 1.8 million GJ in 2013 as set out in its 2012 and 2013 EEC Plan and IR responses.[683] Additional natural gas savings from new program areas would result in savings above this amount.

[683] Exhibit B-25, Appendix 1, p. 4 and Exhibit B-67, BCUC IR 3.3.1.

	The participants in the 2012 and 2013 Furnace Scrap-it program, for example, are estimated to achieve combined savings of 106,417 GJ annually.[684]
(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;	The FEU have an Innovative Technologies Program Area designed to meet this objective. The FEU's proposed Thermal Energy for Schools and Solar Thermal programs would also further this objective.
(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;	As described above, the FEU's EEC programs will result in substantial natural gas savings. This will in turn lead to commensurate reductions in greenhouse gas emissions.
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;	The FEU's "Switch N Shrink" program fosters this objective by encouraging the switching from higher carbon oil and propane heating systems to natural gas using high efficiency furnaces, resulting in a reduction in greenhouse gas emissions.[685] The FEU's proposed Thermal Energy for Schools and Solar Thermal programs would also further this objective.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;	All of the FEU's EEC programs meet the objective of encouraging communities to reduce greenhouse gas emissions and use energy efficiently. The FEU Conservation Education and Outreach Program Area in particular is aimed at achieving this objective

[684] Exhibit B-9, BCUC IR 1.202.4.

[685] Exhibit B-67, Attachment 4.1.1 to BCUC IR 3.4.1.1.

	through education.
(k) to encourage economic development and the creation and retention of jobs;	The FEU's EEC Programs also have a broad impact on the provincial economy as measured through employment, GDP and industrial output. The Conservation Potential Review (CPR) provides a summary of the significant potential economic impact of the FEU's EEC activities.[686]

436. The FEU submit that the Commission's consideration of British Columbia's energy objectives must weigh heavily in favour of the FEU's proposals to expand investment in cost-effective EEC programs.

The FEU's Most Recent Long-Term Resource Plan

437. The Commission accepted the FEU's 2010 Long-Term Resource Plan ("2010 LTRP") in Commission G-14-11, dated February 1, 2011. The 2010 LTRP contained three EEC scenarios illustrating the range of EEC funding scenarios, with further analysis in the form of an updated CPR being required to make an application for EEC funding.[687] The Commission was satisfied that the FEU intended to pursue adequate, cost effective demand-side measures. The FEU have since completed the CPR, and it was filed with the Application. The proposed EEC portfolio based on the CPR is aligned with the 2010 LTRP.

Cost-effective Within the Meaning Prescribed By Regulation

438. The Commission is required to consider whether FEU's proposed EEC expenditures are cost-effective within the meaning of the DSM Regulation. Section 4 of the DSM Regulation prescribes a number of parameters for the Commission's assessment of cost-effectiveness, to which the FEU's EEC proposal adheres.

439. The relevant parameters set out in the DSM Regulation can be summarized as follows:

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[686] Exhibit B-1, Appendix K-2, FortisBC Conservation Potential Review, p. 41 to 42. The full CPR, including the full study regarding the impact on the economy, is provided in Exhibit B-9-1, Attachment 196.1.

[687] 2010 Long Term Resource Plan Decision, dated February 1, 2011, at p. 17.

- **Portfolio Analysis:** The Commission may consider cost-effectiveness of demand-side measures individually, in a group, or as a portfolio as a whole. However, "specified demand-side measures" and "public awareness programs" must be considered on a portfolio basis.[688]

  (A) "Specified demand-side measures" include: education programs for students, funding for energy efficiency training, a community engagement program and a technology innovation program.[689]

  (B) A "public awareness program" means a program delivered by a public utility that the Commission is satisfied will likely: (a) increase the awareness of the public about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or (b) increase participation by the public utility's customers in other demand-side measures proposed by the public utility.

- **Low-Income Programs:** For a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption (which would include the FEU's Low Income Programs) the Commission must use, "in addition to any other analysis the Commission considers appropriate," the Total Resource Cost (TRC) test and consider the benefit of the demand-side measure to be 130% of its value.

- **Ratepayer Impact Measure (RIM) Test:** The Commission cannot find a demand-side measure not to be cost-effective because it fails the RIM test.

- **Specified Standards:** In considering the benefit of a demand-side measure that, in the Commission's opinion, will increase the market share of a regulated item

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[688] As indicated in 4(5), the Commission must be satisfied that Public Awareness Programs are likely to accomplish the objectives in the definition of "Public Awareness Programs".

[689] Terms defined in section 1 of the DSM Regulation.

with respect to which there is a specified standard that has not yet commenced, the Commission may include in the benefit a proportion of the benefit that, in the Commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

440. The Commission has determined that cost-effectiveness of EEC expenditures be assessed on a portfolio basis. The FEU have evaluated its Low-Income Programs with the TRC test, including a deemed 30% adder. While the FEU have calculated the RIM test results for programs in its 2012-2013 EEC Plan for information purposes, the FEU are not proposing the RIM test as a screening tool. The DSM Regulation does not otherwise specify the test to be applied in evaluating the portfolio. The Commission has approved the TRC test for use by the FEU but, as discussed later in this Part, the FEU are proposing that the Commission adopt the Societal Cost Test (SCT) as the primary cost-effectiveness test for EEC.

Interests of Persons in British Columbia who Receive or may Receive Service

441. The FEU submit that its EEC proposals are in the interests of customers and potential customers as they encourage energy efficiency and conservation, reduce GHG emissions, are beneficial to the economy and are cost-effective. Individual customers that avail themselves of EEC measures will reduce their natural gas consumption and, all else equal, their natural gas bills.

(c) Legal Framework Summary

442. The following submissions will address FEU's EEC proposals within the legal framework of the UCA and DSM Regulation. The FEU submit that taking into account the considerations required under the UCA and the DSM Regulation, the proposed EEC expenditures are in the public interest and should be accepted by the Commission.

C. ASSESSING THE COST EFFECTIVENESS OF EEC

443. As discussed above, when considering whether a DSM expenditure schedule is in the public interest, the Commission is required to consider whether the expenditures are cost-

effective as prescribed by the DSM Regulation. While the DSM Regulation imposes some parameters regarding cost-effectiveness, the Commission retains discretion with respect to how to measure cost-effectiveness. The FEU submit that in exercising this discretion, the Commission should be guided by industry standards, the unique context of the FEU in the province of B.C., as compared to electric utilities, and British Columbia's energy objectives. These considerations support:

- the continued use of the portfolio approach for determining cost-effectiveness;
- the adoption of the Societal Cost Test (SCT) instead of the TRC test; and
- the incorporation of spillover effects.

(a) Portfolio Approach Remains Appropriate

444. In the 2008 EEC Application, the Commission determined that cost-effectiveness of EEC should be assessed at the portfolio level, such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. The Commission directed FEI and FEVI to provide information in annual reporting as to why individual programs and measures with a benefit-cost result of less than 1.0 should continue, including information on any other goals supported by the program or measure.[690] The portfolio approach was also approved as part of the Negotiated Settlement Agreements for FEI and FEVI's 2010 and 2011 revenue requirements.[691] The FEU submit that there are several reasons, discussed below, to maintain the portfolio approach going forward.

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[690] Order G-36-09, Reasons for Decision, p. 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 of measure with an individual TRC of less than 1.0 are proactively designed or sufficiently support social or environmental objectives. 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."

[691] Order G-141-09 and G-140-09. See Exhibit B-9, BCUC IR 1.205.1.

445. First, a portfolio approach is consistent with industry practice.[692]

446. Second, according to section 4(4) and (5) of the DSM Regulation, the Commission must, at a minimum, use the portfolio approach in assessing the costs and benefits of "specified demand side measures" and "public awareness programs". A number of the FEU's programs qualify as "specified demand side measures", and must be assessed at the portfolio level. They include, for instance: the "School Programs" in its Conservation Education and Outreach Program Area;[693] parts of the Efficiency Partners Program aimed at training;[694] Energy Efficiency Home Retrofit Programs – Joint Initiatives with Governments and Utilities (LiveSmartBC and other opportunities) as community engagement programs; the innovative technology programs within the FEU's Innovative Technology Program Area;[695] and, the FEU's proposed new Thermal Energy for Schools and Solar Thermal programs. "Public awareness programs" include those programs in the Conservation Education and Outreach Program Area that do not involve a public entity such as a municipality.

447. Third, a portfolio approach to cost-benefit analysis promotes the Companies' goal of making EEC accessible to all customers. Some of the programs that have difficulty passing the TRC test (and in some cases the SCT as well) are programs in the residential and low-income areas.[696] Moving away from a portfolio approach will result in fewer EEC programs, or no EEC programs (depending on the cost-effectiveness test adopted) being available to the residential and low-income customer groups. This would be inconsistent with British Columbia's energy objectives as discussed above. The FEU also note that section 3(a) of the DSM Regulation requires a utility to have programs for low-income households within its planned DSM portfolio. Adopting a cost-effectiveness regime which makes it impossible for low-income programs to be accepted would run contrary to that requirement.

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[692] See, e.g., Exhibit B-9-1, Attachment 196.2, CPUC Energy Efficiency Policy Manual, p. 9, paragraph 6. Mr. Plunkett concurred: Exhibit C4-4, BCSEA Evidence, pp. 18 to 19.

[693] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, pp. 64 to 67.

[694] Exhibit B-67, BCUC IR 3.14.2.

[695] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, pp. 73 to 83.

[696] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, p. 8 and 23.

448. Fourth, the portfolio approach permits the Companies to encourage increasing levels of efficiency in natural gas equipment. Equipment that is relatively new to the market may have a higher initial cost due to the fact that it has not yet reached economies of scale. As a result, it is more likely to have a TRC, or SCT if approved, lower than 1.0.[697] Despite the present results being unfavourable, the long term prospects for such equipment to provide benefits to customers may be significant.

449. For these reasons, the FEU submit that the portfolio approach remains appropriate and is in the public interest. The FEU will monitor individual EEC programs on a monthly basis to ensure that the overall EEC portfolio maintains the required cost-effectiveness on an ongoing basis.[698] The FEU will continue to report on actual portfolio cost-effectiveness results in its Annual Reports.

(b) Test Used For Determining Cost Effectiveness of the Portfolio

450. In this section, we address the appropriate test for determining the cost-effectiveness of the Companies' EEC portfolio. A portfolio consisting of the FEU's proposed "conventional" EEC activity (i.e. Program Areas previously approved by the Commission) already passes the currently approved TRC test; however, the adoption of a test that recognizes broader societal or non-energy benefits of the FEU's EEC activity is a precondition of pursuing the worthwhile new Program Areas outlined in the Application (Furnace Scrap-It, Thermal Energy for Schools, and Solar Thermal). While the FEU will continue to report on the UCT, PAC and RIM results, these tests should not be used as the cost-effectiveness screen for pursuing EEC activity.

[697] Exhibit B-70, Corix IR 3.4.1.
[698] Exhibit B-70, Corix IR 3.4.

Total Resource Cost Test vs. Societal Cost Test

451. The Commission approved the use of the TRC test[699] in the EEC Application Decision.[700] The activity included in the 2012-2013 EEC Plan in existing Program Areas, considered as a portfolio, has a TRC ratio greater than 1.0.[701] However, the TRC of the FEU's proposed new Program Areas (Furnace Scrap-It, Thermal Energy for Schools, and Solar) is quite low, and their inclusion in the overall EEC portfolio would result in the portfolio TRC being less than 1.0. Thus, the FEU will not implement these new Program Areas while the TRC test remains the applicable cost-effectiveness test.

452. The Furnace Scrap-It, Thermal Energy for Schools, and Solar Thermal Program Areas, despite failing the TRC test, do confer real benefits, but the nature of the TRC test is such that non-energy benefits do not become inputs in determining cost-effectiveness. Examples of such benefits include :

- Furnace Scrap-It: Job creation, improved comfort, health benefits, reduced customer O&M.

[699] The California Standard Practice Manual (Exhibit B-25, Appendix 2) describes the Total Resource Cost Test (at p. 18) as a cost effectiveness test which "measures the net cost of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." The "benefits" portion of the TRC test is made up of the avoided supply costs, valued at their marginal cost, for periods when a load reduction results. These benefits are "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." The "costs" portion of the TRC test is made up of the program costs paid by the utility and the participants plus any increase in supply costs for periods when load is increased. This is a broad category, and includes all equipment costs, installation, operation and maintenance costs, cost of removal (less any salvage value), and administration costs, regardless of who pays, less any tax credits. For fuel substitution programs, costs also include any increase in the supply costs of the utility providing the chosen fuel. The benefit-cost ratio is the ratio of discounted total program benefits to discounted total program costs over a specified period of time. A benefit-cost ratio greater than one indicates the program is beneficial, on the basis of the TRC test.

[700] Order G-36-09, Reasons for Decision, p. 32

[701] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, p. 4. This is consistent with the results of the 2009 and 2010 EEC portfolios as reported in the 2009 and 2010 EEC Annual Reports: Exhibit B-1, Appendices K-3 and K-4.

- Thermal Energy for Schools: growth of "green economy" jobs; improved air quality and learning environment in school buildings; and exposure of students and staff to energy efficiency and conservation through retrofitted buildings.[702]

- Solar Thermal: job creation and environmental attributes.[703]

453. The Societal Cost Test (SCT) proposed by the FEU is a variant on the TRC, which is intended to represent a broader societal view of cost-effectiveness. It recognizes non-energy benefits. The proposal to adopt the SCT is consistent with the findings of the study by ICF Marbek on options to the TRC test, which stated for example:[704]

> The Total Resource Cost (TRC) Test, which is one of the California Standard Tests (CSTs), has been widely used since the 1980s by North American utilities and regulatory bodies to determine cost-effective levels of EE investment. In that time EE initiatives have changed significantly in terms of both technologies and programs, and have expanded from a resource acquisition focus to market transformation. However the TRC test has not changed substantially in that time and, particularly as EE programs have become more aggressive, a growing number of EE practitioners have begun to identify challenges associated with reliance on the TRC test. These challenges become even more apparent as EE program objectives are expanded to address GHG reduction targets.

454. As further discussed in the ICF Marbek study,[705] the Companies' EEC activity is increasingly expected to support government policy. Government policy incorporates wider goals than just the energy savings that are reflected in the TRC test, such as achieving GHG reductions, or providing programs for low income customers. These policy objectives are set out in British Columbia's energy objectives and in the DSM Regulation.

455. Mr. Plunkett supports the use of the SCT. His evidence echoes the passage from ICF Marbek on the benefits of the SCT relative to the TRC:[706]

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[702] Exhibit B-9, BCUC IR 1.204.1.1

[703] Exhibit B-1, Appendix K-1, pp. 13 to 14.

[704] Exhibit B-9-1, Attachment 196.1, Options to the TRC Benefit-Cost Test.

[705] Exhibit B-9-1, Attachment 196.1, Options to the TRC Benefit-Cost Test.

[706] Exhibit C4-4, pp. 15 to 17.

> The TRC test does not capture everything of value to society at large or in some cases to customers. Unpriced environmental air pollutants (including greenhouse-gas emissions) associated with natural gas combustion and electricity supply avoided by energy efficiency investment represent the most important non-monetized source of value counted in societal benefits but excluded from the TRC test. Carbon and other greenhouse-gas emissions have yet to be fully accounted for in wholesale market prices for gas and electricity supply.
>
> As most commonly applied, the TRC test also does not capture nonmonetary benefits such as increased comfort that people feel when they insulate their homes, a benefit that customers appreciate and value. It also does not capture non-resource contributions to efficiency program benefits, such as building increased awareness of and support for energy efficiency on the part of consumers and the supply chain for high-efficiency products and services. Failure to account for these benefits will tend to undervalue the yield from efficiency investments, leading to under-investment in efficiency resources and by default, over-investment in gas supply.
>
> ….
>
> The societal test is widely recognized as an indicator of societal economic efficiency. Efficiency measures whose benefits exceed their costs lower the total societal costs allocated in the economy to satisfy a given level of demand for energy service. Program administrators use the societal test as a tool for gauging net benefits and allocating of program resources between competing measures, programs and portfolio objectives.

456. The SCT proposed by the FEU in this Application will appropriately recognize the broader societal goals recognized in British Columbia's energy objectives, and should be adopted. The adoption of the SCT was supported by BCOAPO as well as BCSEA in the EEC Application.[707] The specific elements of the proposed SCT are discussed later in this Part.

Use of Utilities Cost Test (UCT) is Unnecessary

457. Mr. Plunkett advocates the use of the Utilities Cost Test (UCT) in conjunction with the SCT.[708] The UCT counts only the costs of efficiency investments incurred by program

[707] Order G-36-09, Reasons for Decision, p.34.

[708] Exhibit C4-4, Evidence of Mr. Plunkett, pp. 17-18. The UCT is also known as the Program Administer Cost (PAC) test, which is a term that Mr. Plunkett uses.

administrators and supported by ratepayers, and only the benefits of avoided supply costs of the sponsoring utility. It does not include the value of non-gas resource savings in the calculation of benefits; nor does it include customers' contribution toward efficiency investments in the calculation of costs.[709] The FEU report on the results of the UCT in the EEC Annual Reports and in the 2012-2013 EEC Plan and are open to using the SCT in conjunction with the UCT on a portfolio basis. However, in the event that the Commission determines to continue using the TRC test, the FEU submit that it is unnecessary to adopt the UCT as an additional screen at this time. There are two reasons for this.

458. First, as stated in California's Energy Efficiency Policy Manual, "In almost all instances, an energy efficiency program that passes the TRC test will also pass the PAC [UCT] test."[710] The FEU's 2012-2013 EEC portfolio has a UCT ratio of 1.97, and thus using the portfolio UCT for the proposed 2012 and 2013 expenditures would not result in the screening out of any programs. There is only one EEC program in FEU's 2012-2013 EEC Plan that passes the TRC but fails the UCT.[711] This is the Occupancy Sensors/Controls program which is part of the Innovative Technologies area. Innovative technologies programs are "specified demand-side measures" and are required to be assessed on a portfolio basis pursuant to the DSM Regulation. Accordingly, the UCT result should not be used to screen out this program.

459. Second, the programs that have a lower UCT than TRC or SCT result are in the Low Income Program Area. These programs are pursued by the FEU to satisfy requirements for portfolio adequacy enshrined in the DSM Regulation and to promote the FEU's principle of universality – to offer programs to all customer groups. These programs fail the TRC, UCT and SCT. Servicing this sector requires fully funding the measures, rather than just the incremental cost. Thus the "cost" side of the equation for low income programs is considered to be the full cost of the measure, rather than the incremental cost of the efficient option as is the case for the "able-to-pay" segments of the portfolio. Consequently, it is very difficult to achieve

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[709] Exhibit C4-4, Evidence of Mr. Plunkett, pp. 17-18. Also known as the Program Administer Cost (PAC) test.

[710] Exhibit B-25, Appendix 2, p. 9.

[711] Note that, by its nature, the UCT cannot be applied to high-carbon fuel switching programs.

favourable TRC results in the Low Income Program Areas.[712] For similar reasons, it is difficult to achieve favourable UCT results. The FEU submit that it would not be in the public interest to screen out these low-income programs based on the UCT results.

Participant Cost Test (PCT) and Ratepayer Impact Measure (RIM) Should Not Be Used

460. The FEU have provided PCT and RIM results in its 2012-2013 EEC Plan and propose to continue to report on the test in its EEC Annual Reports. However, these tests should not be used as a screen for EEC. The PCT suffers from some shortcomings that limit its use as a screen. Mr. Plunkett explained:[713]

> The PCT is a valid indicator of how much a customer is better off with the efficiency investment. In practice it is too weak a test of the financial attractiveness of the investment. Market barriers originate from the cash-flow burden of putting down money up front. Industry best practice is to structure financial incentives for retrofit investments so that the participant's up-front contribution is no more than the first year's estimated bill savings. For market-driven efficiency opportunities, financial incentives (upstream and/or downstream) are often set to cover the entire incremental cost, rending the participant test is meaningless. Consequently, the participant test is rarely used in assessing the cost-effectiveness of efficiency programs or portfolios. Financial analysis of project cash flows, including internal rate of return, is far more useful in calculating efficiency investment value to participants.

The Commission is precluded by the DSM Regulation from using the RIM test to disallow a DSM expenditure for a demand-side measure.[714]

(c) The Attributes of the Proposed SCT

461. As discussed above, the SCT is a variant on the TRC test that provides a more balanced view of the true costs and benefits of EEC programs. The FEU's SCT consists of the following modifications to the TRC test:

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[712] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, p. 23-26.

[713] Exhibit C4-5, BCSEA Response to BCUC IR 1.13.2.

[714] DSM Regulation, section 4(6).

- The use of a social discount rate of 3 percent (real)[715], rather than the Companies' weighted average cost of capital ("WACC");
- The use of the ceiling price put forward by the Companies for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas except for fuel-switching programs; and
- The use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity such as job creation and improved human health.

The FEU submit that the adoption of the SCT based on these principles is reasonable and in the public interest. The basis for each of the adjustments is discussed below.

3% Social Discount Rate is Appropriate for the FEU

462. The discount rate currently being used to evaluate EEC programs is based on the Companies' WACC. Discounting at the FEU's WACC has the effect of according very little value to energy savings occurring beyond about the 7th year after a measure has been installed, even though savings may accrue for up to 50 years in the case of some measures such as highly efficient new construction and building envelope retrofits.[716] The use of the current discount rate therefore understates the value of natural gas EEC measures as 100% of the cost of a measure is included in the benefit-cost analysis, but not all of the benefits (since much of the future benefits are so heavily discounted they have no material impact on the TRC result). The FEU submit that the proposed 3% social discount rate will better match the benefits of a natural gas EEC measure to its costs. The proposed 3% social discount rate is based on a median of social discount rates used in other jurisdictions, which range from 1.3% to 5%.[717]

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[715] Exhibit B-7, BCSEA IR 1.21.1.

[716] Exhibit B-1, Appendix K-1, pp. 19 to 20.

[717] Exhibit B-9, BCUC IR 1.207.1.

Avoided Cost of Gas at Ceiling Price for Biomethane

463. The avoided cost of natural gas is used to calculate the "benefit" side of the equation in cost-effectiveness analysis of EEC activity. The FEU submit that the ceiling price for Biomethane,[718] and not the cost of conventional natural gas, is the appropriate avoided cost of gas to use when calculating the benefits of EEC programs. As discussed below, the FEU's proposal provides greater stability for EEC investments, and recognizes that EEC is akin to a "green" supply resource.

464. The ultimate goal for much of the FEU's EEC activity is to achieve market transformation. Market transformation requires sustained, long-term utility activity in support of increasing market penetration of efficient technology. However, the avoided cost of gas currently being used is based upon a forward projection of market costs for conventional fossil fuel-based natural gas,[719] which are subject to volatility and fluctuation over time.[720] 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. A more stable basis for determining the avoided cost of gas, which cannot be achieved with a multi-year rolling average, will better align with the goal of achieving market transformation.[721]

465. As an environmentally benign alternative to conventional sources of new supply, natural gas 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. Moving to

[718] Exhibit B-9, BCUC IR 1.208.4. 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.

[719] A explanation of the current avoided cost of gas calculation is provide in response to BCUC IR 1.189.3 (Exhibit B-9).

[720] This volatility is illustrated by the historical AECO daily spot prices since 2000, shown in response to BCUC IR 208.1 (Exhibit B-9). More simply, however, 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. Exhibit B-9, BCUC IR 1.208.4.

[721] Exhibit B-9, BCUC IR 1.208.6.

the ceiling price for Biomethane, which is derived from an efficiency-adjusted cost of "green" electricity, better captures the environmental benefits of natural gas DSM. Biomethane and "green" electricity are considered to be zero-emission sources of energy; DSM activity is also zero-emission. Thus, 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 biomethane and electricity.[722] Whether the avoided cost of Biomethane is lower or higher than conventional natural gas supply, the FEU submit that it is the appropriate avoided cost of supply for the FEU's EEC programs.

Deemed Adder for Non-Energy Savings Benefits

466. The proposed 30% deemed adder gives appropriate recognition to the value of real and material non-energy savings benefits such as economic spin-offs, resource conservation, improved health, comfort and productivity that are otherwise valued at zero in the TRC test.

467. In the EEC Application Decision, the Commission Panel recognized "that societal factors have significance" but considered that these factors as being "rather subjective and difficult to measure".[723] While the FEU agree that quantifying the value of non-energy EEC benefits is challenging, a study completed since the EEC Application Decision demonstrates that the non-energy benefits are material – "overwhelmingly positive for the regional economy as measured by output, GDP, and employment" - and certainly greater than zero.[724]

468. Non-energy benefits are most often quantified for low-income programs. The DSM Regulation uses a 30 percent adder in the context of low-income programs. The FEU provided evidence of the values used for non-energy benefits associated with low-income programs in the United States.[725] Regular DSM programs will have many of the same non-

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[722] Exhibit B-1, Appendix K-1, p. 20.

[723] Order G-36-09, Reasons for Decision, p.34.

[724] Exhibit B-9-1, Attachment 196.1: "Impact of CPR-2010 Natural Gas Savings on the B.C. Economy (2010-2030), at pp. 8 to 9.

[725] Exhibit B-9, BCUC IR 1.209.1.

energy benefits. 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. There is also an 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). Based on the figures cited above, a 30 percent benefits adder for the FEU's DSM programs is a conservative and reasonable proxy for the non-energy benefits.[726]

(d) Spillover Should Be Considered in Conjunction With Free-Riders

469. The concept of Net-to-Gross ("NTG") is employed in the cost-effectiveness analysis to adjust the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the EEC program. Currently, the way in which the FEU calculate NTG only adjusts the benefits downwards for the presumed presence of "free riders", i.e. individuals who participate in a program who would have participated in the absence of an incentive.[727] The FEU submit that the NTG should also account for the benefit of customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program. Accounting for this effect, known as "spillover",[728] in the NTG is a recognized approach that is used by many utilities including BC Hydro.[729] As "spillover" is the conceptual opposite of "free riders", and including both effects presents a more complete and balanced view of program impacts.

470. The FEU have not accounted for "spillover" effects in the 2012-2013 EEC Plan. In this Application, the FEU are seeking only the Commission's endorsement of the appropriateness of recognizing "spillover" effects in the NTG ratio on the FEU's portfolio as a basis for the FEU to proceed with evaluating and quantifying "spillover" effects on the approved EEC portfolio. In future applications for EEC funding, the FEU would propose specific free rider

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[726] Exhibit B-9, BCUC IR 1.209.1.

[727] Exhibit B-1, Appendix K-1, p. 21.

[728] Exhibit B-1, Appendix K-1, p. 21. In addition to BC Hydro, other jurisdictions where the NTG accounts for "spillover effects" include Florida, Illinois, Massachusetts, New York and Oregon. California, Wisconsin and Connecticut account for "spillover" in some cases.

[729] Exhibit B-9, BCUC IR 1.210.2.

and "spillover" estimates based on the results of that evaluation. The FEU submit that it is in the best interests of customers for the Commission to make a determination in this Application regarding the principle of including "spillover" effects before more detailed work is undertaken.

(e) Cost-Effectiveness of Enabling Activities

471. Consistent with industry practice, the FEU's EEC portfolio includes a variety of enabling activities aimed at increasing participation in other EEC programs and building general awareness of energy conservation and efficiency. The Conservation, Education and Outreach Program Area consists exclusively of enabling programs of this nature. There are other examples of enabling programs in other Program Areas.[730] The FEU do not attribute energy savings to its enabling activities and thus, these programs do not have cost-effectiveness test results. The costs of these programs should be incorporated into the benefit-cost test for the portfolio of EEC programs as a whole, as the FEU have proposed. Mr. Plunkett confirmed that this treatment is consistent with industry standard and that he is supportive of the inclusion of such programs in the EEC portfolio.[731]

(f) Cost-Effectiveness of High Carbon Fuel Switching Programs

472. The TRC or SCT test is equally applicable to fuel switching[732] activity. The California Standard Practice Manual states that the TRC test (and by extension SCT, which is a modified TRC) "is applicable to conservation, load management, and fuel substitution programs".[733] For high carbon fuel switching programs such as oil to natural gas conversion, the avoided cost is the higher-carbon fuel (heating oil or propane), and the net benefit used in the TRC calculation is the differential between the avoided higher-carbon fuel cost, and the

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[730] For example, the Energy Specialists Program in the Commercial Sector Program Area.

[731] Exhibit C4-4, Evidence of Mr. Plunkett, p. 18; Exhibit C4-5, BCSEA Response to BCUC IR 14.1.

[732] Fuel-switching for the purpose of efficiency should not be confused with load building. The California Standard Practice Manual 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." Exhibit B-9, BCUC IR 1.194.2.

[733] Exhibit B-25, Appendix 2.

incurred natural gas cost.[734] In applying the SCT, there would be no reference to the cost of Biomethane since there is no "avoided cost" of natural gas. Rather, there is an incurred cost of natural gas and an avoided cost of the higher-carbon fuel.

473. The High-Carbon Fuel Switching Programs do not have UCT results in the FEU's 2012-2013 EEC Plan. This is because the natural gas energy savings is a key component of the UCT calculation. As stated by Mr. Plunkett: "The utility cost (UC) test counts only the costs of efficiency investments incurred by program administrators and supported by ratepayers, <u>and only the benefits of avoided supply costs of the sponsoring utility</u>."[735] [Emphasis added.] The UCT is therefore irrelevant to these programs. The FEU therefore submit that the TRC or the SCT is the appropriate cost-effectiveness tool for High-Carbon Fuel Switching programs.

(g) Summary

474. The FEU submit that its proposed cost-effectiveness regime for its EEC portfolio is reasonable and provides a fair balancing of the costs and benefits of its EEC programs. The Commission should find that it is in the public interest.

D. PROPOSED FINANCIAL TREATMENT

475. The currently-approved financial treatment for EEC funding involves capitalizing the entire approved EEC expenditure to a rate base deferral account on a net-of-tax basis, and recovering deferral account balances from customers over a ten-year period beginning the following year.[736] In 2010 and 2011 the FEU were, for a variety of reasons, unable to spend all of the approved EEC funding. The FEU have proposed a change in the financial treatment for planned EEC expenditures that reflects a reasonable amount of EEC in the delivery rates during

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[734] Exhibit B-9, BCUC IR 1.189.3. The California Standard Practice Manual (p. 18) states, for instance: "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."

[735] Exhibit C4-4, Evidence of Mr. Plunkett, p. 17.

[736] Order No. G-36-09. Exhibit B-1, Appendix K-1, p. 16.

test period, while mitigating the risk of under spending. The key feature of the new financial treatment is to divide the EEC funding in to two components, as described below.

(a) Experience in 2010 and 2011 is Impetus for Proposed Financial Treatment

476. The FEU have proposed a change in the financial treatment in direct response to the difficulties experienced in 2010 and 2011, which were the first two full years of the FEU's expanded EEC portfolio.

477. The EEC funding envelope for 2010 and 2011 for FEI and FEVI was approved at approximately $31 million for 2010 and $35 million for 2011. However, the FEU underestimated the challenges in acquiring EEC staff to roll out its programs in 2010 and 2011; qualified staff proved hard to come by and the short-staffed EEC group struggled to roll out programs based on the planned timeline.[737] The economic downturn, changes in provincial leadership, and lower natural gas prices all affected the demand for incentives as customer interest in energy efficiency and conservation activities took a backseat to short-term financial considerations.[738] The FEU's actual spending for 2010 and 2011 was $10 million and $15.5 million, respectively, which was well below the approved amounts.[739]

478. The financial impact on customers associated with the EEC under-spend in 2010 and 2011 was that during the 2010 and 2011 test period customers paid rates reflecting the WACC on the *forecast* EEC expenditure rather than the WACC on the *actual* EEC expenditure. The unspent EEC dollars (i.e. the difference between the approved portfolio amount and the actual portfolio spend) were not recovered from ratepayers in 2010 and 2011.[740] The FEU quantified the financial implications for customers in 2010 and 2011 in Exhibit B-73.[741] At the end of the test period, the EEC account is trued up such that the next revenue requirement will

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[737] Exhibit B-9, BCUC IR 1.192.1; T9, p. 1551, ll. 3 to 19.

[738] Exhibit B-1, BCUC IR 1.192.1.

[739] Exhibit B-1-3, Revised p. 11 of Application; Exhibit B-73, Undertaking Response No. 40.

[740] Roy: T3, p. 372, l. 20 to p. 373, l. 9.

[741] Exhibit B-73, Undertaking Response No. 40.

reflect the amortization expense based on the actual amount incurred.[742] As Mr. Thomson explained:[743]

> [T]he difference between actual and forecast amortization on the EEC deferral account is not lost, rather it is more appropriately classified as a timing difference. With each successive revenue requirement and reset of delivery rates, FEU re-forecasts the opening deferral account balance based on previous actual EEC costs and, as a result, the amortization of the deferral account is re-forecast to recover the previous actual EEC costs. Thus, over the life of the deferral account, only the actual EEC costs incurred are collected from customers.

As a result, the unspent EEC dollars from 2010 and 2011 were not recovered from customers in the present test period, and will not be recovered in this 2012-2013 test period or future years.[744]

479. The evidence confirms that the FEU are better positioned in 2012 and 2013 in terms of having an existing base of experienced staff and the continuation of many programs from previous years.[745] The economy is showing some tentative signs of recovering,[746] there is more potential for natural gas prices to go up rather than down,[747] and we can expect more political stability until the provincial election in May 2013.[748] Nevertheless, all of these factors still have the potential to affect EEC spending levels in 2012 and 2013. As described below, the FEU have learned from the past experience, and have responded appropriately by proposing a new financial treatment for EEC expenditures.

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[742] Exhibit B-17. BCUC IR 2.1.3

[743] Thomson: T3, p. 374, ll. 5 to 18.

[744] Thomson: T3, p. 374, ll. 5 to 18.

[745] Stout and Smith: T8, p. 1268, l. 19 to p. 1269, l. 11. While there would be a lag to get staff in place for the new program areas, the FEU believe it will be staffed appropriately for existing Program Areas. A 2012 and 2013 staffing plan has been approved and will be implemented. Smith: T8, p. 1266, l. 13 to p. 1267, l. 11 and T9, p.1549.

[746] Exhibit B-17, BCUC IR 2.91.2. Stout: T8, p. 1270, ll. 4 to 6.

[747] Stout: T8, p. 1319, ll. 9 to 11.

[748] Stout: T8, p. 1270, ll. 14 to 20.

(b) Proposed Financial Treatment Involves Two Components of EEC Funding

480. Whereas the current treatment as approved by BCUC Order No. G-36-09 would see the entire portfolio amount for 2012 and 2013 ($64.5 million each year) included in the rate base deferral account, the FEU have proposed to limit the amount to be included in the rate base deferral account to $15 million each year (as discussed below, this amount is reduced from the original proposal of $20 million). The base amount will be capitalized to a rate base deferral account, and recovered from customers over a period of ten years.[749] The FEU propose to allocate the non-incentive costs in any approved base amount amongst FEI, FEVI and FEW on an average customer basis, which is consistent with the treatment of other costs in the FEU, like Core Market Administration Expense.[750] Incentive costs will be allocated on an as-incurred basis.

481. The FEU propose to capture costs incurred over and above the forecast EEC rate base account additions of $15.0 million in 2012 and 2013 in a new non-rate base deferral account, attracting AFUDC, on an as-spent basis to a maximum of $49.5 million each year amongst the FEU. The additions to the non-rate base account will be tracked on a Company basis for Mainland, Vancouver Island and Whistler, and as with the rate base account, non-utility-specific costs in the non-rate base account will be allocated on an average customer basis amongst FEU.[751] Consistent with the rate base deferral accounts, the balance in the non-rate base account will be recovered over a ten year period. The recovery of the balance will commence in 2014, with the method of recovery to be determined as a part of the next Revenue Requirement.[752]

482. The FEU had initially sought approval for $20 million per year as the dividing line between the first and second funding components. However, the primary rationale for

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[749] Exhibit B-1, p. 392.

[750] Exhibit B-9, BCUC IR 1.104.2. 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.

[751] Exhibit B-1, p. 395 and Exhibit B-9, BCUC IR 1.104.2, p. 349-352

[752] Exhibit B-1, p. 395.

originally selecting $20 million per year as the amount to reflect in rates during the test period had been that $20 million was in line with the total projected EEC costs for 2011 at that time.[753] The updated projected F2011 spending (determined in response to an undertaking following the hearing) of approximately $15 million[754] warrants the reduction of the threshold from the original $20 million to $15 million.[755]

483. The proposed approach has two benefits:

- First, aligning the rate base component with the 2011 actual spend ensures that a reasonable amount of EEC is reflected in the delivery rates during test period. Under the existing financial treatment, 1/10 of the $15 million will be recovered in 2013, whereas the amounts accruing to the new non-rate base deferral account will be recovered starting in 2014.

- Second, using the proposed non-rate base account to capture amounts above the current level recognizes that actual EEC spending depends in large degree on the number of customers availing themselves of incentives, which in turn depends to a degree on the state of the economy and natural gas prices. The proposed financial treatment permits the FEU to pursue greater cost effective EEC activity, while reducing the risk of variability in EEC costs.

(c) Summary

484. The FEU submit that its proposed financial treatment is in the public interest and should be accepted by the Commission. As the proposed financial treatment addresses the risk that the FEU will be unable to spend the EEC funding, the overall portfolio amount discussed in the next section takes on the character of an upper limit on cost-effective EEC funding in the test period.

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[753] Exhibit B-1, pp. 394 to 395 as amended by Exhibit B-1-3.
[754] Exhibit 73, Undertaking No. 40.
[755] Stout: T9, p. 1543, l. 24 to p. 1545, l. 18.

E. FUNDING LEVEL FOR EXISTING PROGRAM AREAS

485. In this section, the FEU describe the evidence supporting the proposed funding level of $39.5 million per year for existing Program Areas (new Program Areas are addressed in Section G below). The FEU have supported its proposed expenditures in existing Program Areas with a Conservation Potential Review ("CPR"), and a detailed EEC Plan for 2012-2013 that includes incentive levels and participant count estimates for each program. The FEU submit that its proposed funding level for EEC expenditures within existing Program Areas is in the public interest and should be accepted by the Commission.

(a) 2012-2013 EEC Plan Provides Basis for Activity in Existing Program Areas

486. The 2012-2013 EEC Plan, which builds upon the CPR results[756], provides details on existing and new programs within previously approved Program Areas. Significant additional information about the 2012-2013 EEC Plan has been provided in response to information requests and undertakings. In particular, the FEU note the responses to BCUC IR 2.97.1[757] and 3.1.2.1,[758] which provide details on the FEU's assumptions, sources and other detailed information related to its existing and new programs in the 2012-2013 EEC Plan.

487. The level of requested funding for existing Program Areas has increased compared to 2011 in part to account for the extension of the existing Program Areas to FEW and Fort Nelson. It also reflects the anticipated increase in customer take-up as the FEU's EEC programs gain traction in the marketplace. The 2012-2013 EEC Plan also includes a number of new programs within the existing Residential[759], Commercial[760] Industrial[761] and Conservation

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[756] The Conservation Potential Review (CPR) completed in 2011, which demonstrates the potential for energy savings in the Province, provided the data required to support the energy savings forecast in the 2012-2013 EEC Plan. A detailed account of how the CPR was used in the creation of the 2012-2013 EEC Plan is provided in response to BCUC IR 3.2.1.

[757] Exhibit B-17.

[758] Exhibit B-67.

[759] New programs in the Residential Program Area: ENERGY STAR Domestic Hot Water "DHW" Technologies (Condensing Water Heaters and Tankless Water Heaters); ENERGY STAR Washers and Other Measures for DHW Conservation; Customer Engagement Tool for Conservation Behaviours; New Construction – EnerGuide for Homes (80 & beyond) Efficient Appliances.

Education and Outreach[762] Program Areas that are expected to realize significant energy savings for customers. A complete list of new programs within existing Program Areas is provided in the response to BCUC IR 3.1.2.[763]

488. The 2012-2013 EEC Plan includes TRC, SCT and UCT test results at the program, Program Area and portfolio levels. With favourable TRC, SCT and UCT test results for the portfolio as a whole, the 2012-2013 EEC Plan is cost-effective whether or not the Commission accepts the FEU's proposed SCT or continues to use the TRC test as the primary cost-effectiveness screening tool. The cost-effectiveness of the FEU's portfolio is supported by the FEU's 2010 EEC Annual Report, which shows that the FEU's portfolio of EEC programs has been cost-effective to date, with a TRC benefit-cost ratio of greater than 1.0.

489. Mr. Plunkett, an expert in the economics of DSM,[764] opined that the FEU's "proposed plan is generally reasonable in terms of expenditure levels and market coverage".[765] Mr. Plunkett confirmed that the FEU's proposed EEC expenditures are "within the range of investment by its peers". He emphasized the potential customer benefits available by pursuing those measures at the levels proposed: "Indeed, it is highly likely that Fortis can continue increasing annual DSM expenditures in pursuit of additional natural gas efficiency resources achievable for less than the avoided cost of gas supply, as other utilities have done and are continuing to do, by steadily increasing market penetration over time."[766] Although Mr.

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[760] New programs in the existing Commercial Sector Program Area: Commercial Custom Design Program; Continuous Optimization Program; Commercial Kitchens Program; MURB Program; Process Heat Program.

[761] New program in the existing Industrial Sector Program Area: Industrial Technology Retrofit Program - Lime Kiln Chain System Upgrade Program.

[762] New programs in the Conservation Education and Outreach Program Area: Residential Mass Education on Conservation and Energy Literacy; Medium-Large Commercial Education Sessions; Home Efficiency Measures; Behaviour Programs – Energy Specialists; School Programs: Class and Online Curriculum.

[763] Exhibit B-67.

[764] Plunkett: T8, p. 1246, l. 6 to p. 1248, l. 2.

[765] Exhibit C4-4, Evidence of Mr. Plunkett, p. 6, ll. 11 to 12.

[766] Exhibit C4-4, Evidence of Mr. Plunkett, p. 8, l. 24 to p. 9, l. 2.

Plunkett had initially indicated that he believed further information was necessary, he ultimately agreed that the 2012-2013 EEC Plan provided the requisite information.[767]

(b) Conclusion on Funding Level for Existing Program Areas

490. The FEU submit that the evidence supports the proposed funding levels for existing Program Areas, reflecting the new programs within these Program Areas and the extension of these Program Areas to the Whistler and Fort Nelson service areas.

F. ISSUES RAISED REGARDING EXISTING PROGRAM AREAS

491. In the following sections, the FEU will canvass the particular issues by participants in this proceeding (particularly in the third round of IRs and at the oral hearing) related to its 2012-2013 EEC Plan for the existing Program Areas. The FEU have provided full responses on those topics.

(a) Furnace TLC Program

492. The FEU are proposing to continue the "Give your Furnace/Fireplace some TLC" as part of the 2012-2013 EEC Plan.[768] The 2010 program was described in the FEU's 2010 EEC Annual Report.[769] The proposed program is described on page 11 of the 2012-2013 EEC Plan. Further details on the program are provided in response to BCUC IR 2.128.1 (Exhibit B-17) and BCUC IR 3.9.1 to 3.9.4.1 (Exhibit B-64).

493. Ms. Smith described the program as follows:[770]

> So, the customer calls up a contractor and asks the licenced gas contractor to come and service their furnace in 2010, and in 2011 we expanded the program to include fireplace servicing. The contractor shows up and does the servicing, which consists of -- typically would consist of removing and cleaning the burner assembly within the furnace, looking for cracks on the heat exchanger in the furnace, removing and cleaning the blower fan, checking and replacing the fan

[767] Plunkett: T8, p. 1254, ll. 14 to 23.

[768] Exhibit B-25, Appendix 1, p. 10.

[769] Exhibit B-1, Appendix K-4, beginning at p. 27.

[770] Smith: T9, p. 1354, l. 22 to p. 1355, l. 16.

> belt as needed, checking the auto shut-off switch on the furnace, which is the switch that shuts the furnace down if it gets too hot, and inspecting the flue and the piping. So the licensed gas contractor would perform that work. The customer would pay the contractor and send in a copy of the program application form with the invoice from the gas contractor attached, and if the customer falls within the program parameters, which basically are timelines in the case of this program, a $25 Save On More gift card is sent to them.

494. This type of program is offered in many other jurisdictions. Ms. Smith testified that there are 71 tune-up programs of various kinds across North America.[771]

495. The FEU's approach of relying on contractors to promote the program is cost-effective. The FEU use the Energy Efficiency Partners program and other means to ensure contractors are adequately informed.[772] As described by Ms. Smith, the FEU have now launched a "Find a Contractor" function on its website which can assist customers in finding a licenced contactor; using a contractor licensed by the BC Safety Authority to perform the service is part of the program eligibility criteria.[773]

496. In cross-examination, it was suggested that a possible shortcoming in the 2010 program was that it is not explicitly stated that its goal is to have customers actually upgrade their furnaces so that there are verifiable energy savings.[774] In the FEU's submission, the evidence is clear that one of the goals and benefits of the program is to have customers upgrade their furnace:

- One of the goals of the 2010 program was to "provide education and awareness about energy efficient appliances and their maintenance." Another goal was to: "Engage customers and contractors in conversations about…the opportunity to upgrade existing mid-efficiency appliances to high-efficiency appliances."[775] The awareness of, and conversations about opportunities to upgrade to, high-

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[771] Smith: T9, p. 1359, ll. 3 to 12.
[772] Exhibit B-67, BCUC IR 3.9.4.
[773] Smith: T9, p. 1356, l. 12 to p. 1357, l. 17.
[774] Smith: T9, p. 1357, ll. 21 to 24.
[775] Exhibit A2-6, p. 2; T9, p. 1357, l. 25 to p. 1358, l. 6.

efficiency appliances is of course essential to getting customers to upgrade their appliances and the only reason to seek to improve that awareness and have those discussions must be, in fact, to have customers upgrade their appliances.

- In any event, the Program Description in the 2012-2013 EEC Report now states the goal clearly: "It is also expected that this approach will create opportunities to upgrade appliances to more efficient models."[776]
- The 2010 EEC Annual Report indicates that 15% of participants were advised to upgrade their furnace.[777]
- Half of the participants who were encouraged to upgrade or replace their furnace, replaced or upgraded to a high-efficiency appliance.[778]

497. It was also suggested that the FEU should be offering incentives to upgrade furnaces. The FEU have proposed the Furnace Scrap-it Program to provide such an incentive, as described in section G below.[779]

498. It is standard practice in the industry not to attribute savings to enabling activities like the "Give your Furnace/Fireplace some TLC" program, and to treat enabling activities as portfolio-wide costs.[780] Ms. Smith indicated that it would be very challenging to quantify the savings.[781] However, the 2010 "Give your furnace some TLC" participant survey demonstrated that there are energy savings as a result of the program by way of leak repairs, addressing technical issues, and equipment upgrades.[782]

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[776] Exhibit B-25, Appendix 1, p. 11.
[777] Exhibit A2-6, p. 3.
[778] Exhibit B-17, BCUC IR 2.128.1. T9, p. 1362, l. 21 to p. 1363, l. 4.
[779] Smith and Bennett: T9, p. 1361, ll. 10 to 22.
[780] Exhibit C4-5, BCSEA Response to BCUC IR 14.1.
[781] Smith: T9, p. 1359, ll. 13 to 19.
[782] Exhibit B-17, BCUC IR 2.128.1.

499. Finally, it was suggested the FEU should be having contractors install low-cost efficiency measures while they are on the customer premises.[783] This suggestion, however, would not likely be cost-effective and poses logistical issues.[784] The FEU are, however, investigating the possibility of providing retailer discount coupons for customer to take advantage of low-cost measures in 2012.[785]

500. The FEU submit that the "Give your Furnace/Fireplace some TLC" is an important piece of the overall cost-effective EEC portfolio and is being implemented appropriately.

(b) Hot Water Technologies Programs

501. The FEU offered an "Energy Efficient Residential Hot Water Storage Tank" Program in 2010 and 2011 as described in the 2010 EEC Annual Report and plan to offer the new "ENERGY STAR Domestic Hot Water Technologies" program described in the 2012-2013 EEC Report and the response to BCUC IR 3.1.2 (pages 6 to 14). The new program will be informed by the evaluation of the 2010-2011 water heater program.[786]

502. In cross-examination it was suggested that there should be no savings attributed to FEU's 2010 and 2011 program to incent the purchase of 0.62 EF water heaters after September 1, 2010 when the province instituted a 0.62 EF standard for water heaters. This issue was addressed in response to BCUC IR 2.129.1 and further in cross-examination. The reasons for offering incentives for the 0.62 EF are, in summary, as follows:[787]

(a) The 0.62 EF water heater program was a first step in a national water heater transformation strategy. Even though water heaters represent 21% of residential natural gas consumption, water heating technology has not improved much over the past 50 years.

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[783] Smith: T9, p. 1363, l. 12 to p. 1364, l. 4.

[784] Smith and Bennett: T9, p. 1364, l. 4 to p. 1366, l. 24.

[785] Exhibit B-67, BCUC IR 3.9.2.

[786] Exhibit B-74, Undertaking No. 41.

[787] Exhibit B-1, Appendix K-4, pp. 30 to 34; Exhibit B-17, BCUC IR 2.129.1. to 2.129.5; T9, p. 1368, l. 3 to p. 1375, l.14.

(b) The 0.62 EF water heater program:

- educated the market about the introduction of provincial regulations on September 1, 2010;
- educated consumers about choosing energy efficient water heaters and the importance of hot water conservation;
- developed partnerships with manufacturers, distributors, contractors and retailers, which will help drive future hot water heater technology programs;
- helped drive product labeling as an important first step in efficiency awareness;
- created an online directory of eligible water heaters, which would otherwise not exist;
- helped drive manufacturer compliance with the existing 0.62 EF regulation; and
- provided an opportunity to encourage home owners to retire their hot water heaters early.

(c) A program for higher efficiency units is being introduced in 2012 and 2013. To prevent potential market confusion due to starting and stopping a water heater program, it was important to continue the 0.62 EF water heater program until the new program in 2012 was implemented. As stated in the 2010 EEC Annual Report (p. 33): "Most importantly, the base offer is the foundation for maintaining relationships with the supply chain required for the next stages of the DHW market transformation strategy. As we collaboratively work with stakeholders on a national strategy aimed at raising the bar on efficiency, it is important to have programs in place to guide the market and policy decisions."

503. The FEU's new program for 2012 and 2013, entitled "ENERGY STAR Domestic Hot Water Technologies," will be providing incentives to increase the adoption of storage tank

water heaters with 0.67 EF, condensing water heaters with .80 EF, and tankless water heaters greater than 0.82 EF.[788]

504. The FEU's forecast participation rates for the program are reasonable. As explained in detail in response to Undertaking No. 42, the projected participation rate of 5100 participants in the 2012 and 2013 ENERGY Star water heater program is based on estimating participation as a percentage of total market share of natural gas water heater storage tanks in addition to extrapolating from 2011 program participation rates.[789] While the 2010 program had a low rate of participation of 172, the 2011 program has a participation rate of 2011, with a quarter of the year remaining. This reflects a significant increase in participation over 2010 and is consistent with the FEU's forecast participation rate of 5100 for 2012 and 2013. As explained by the FEU witnesses, there are good reasons to anticipate that in 2012 and 2013 participation rates will continue to increase considering that the program includes a broader range of end use measures at higher incentive levels.[790]

505. The calculation of a free rider rate was also the subject of cross-examination. As explained by Ms. Smith, while the FEU use different methods to calculate free riders, in the case of the 2012-2013 ENERGY STAR Domestic Hot Water Technologies program, a free rider rate of 10% was used based on market share of 0.67 EF water heaters. The current market share of a measure indicates what the level of customer uptake for that measure is without a program. The 10% rate was used as an overall average for all technologies in the program, which results in a conservative free rider estimate.[791] Once the program has been in place for an adequate length of time for an evaluation to be conducted, a free rider rate based on actual results will be used.[792]

[788] Exhibit B-67, BCUC IR 3.1.2.
[789] Exhibit B-75.
[790] Smith and Stout: T9, p. 1379, l. 4 to p. 1382, l. 22.
[791] Smith, Stout and Bennett: T9, p. 1387, l. 4 to p. 1390, l. 6.
[792] Smith: T9, p. 1392, l. 5 to p. 1393, l. 17.

(c) Customer Engagement Tool for Conservation Behaviours

506. The FEU's 2012-2013 EEC Plan includes a new Customer Engagement Tool for the Conservation Behaviours program within the Residential Program Area. This program is a tool to provide customers with a comparison of their energy consumption in relation to an aggregate of neighbouring residential customers.[793]

507. Cross-examination from Commission counsel suggested that the FEU's energy savings estimate may have been too optimistic. In fact, the FEU's estimate has been very conservative. First, the FEU participant count is entirely within the FEU's control as participants are simply those customers who are provided with the consumption reports.[794] Second, the FEU have made a very conservative estimate of energy savings per customer of 0.25 GJ per participant in 2012 and a 1.0 GJ of savings per participant for 2013. Ms. Smith explained that some participants will realize savings of much more, while others may realize none.[795] The energy savings estimate is based on credible third party research of similar programs.[796] Research also indicates that energy savings for these programs increase in subsequent years of the program.[797]

(d) Evaluation, Measurement and Verification

508. The focus of the inquiries regarding the FEU's evaluation, measurement and verification ("EM&V") framework was on how the work has been done to date in the initial start up period of the FEU's EEC activity. The FEU described the current EM&V process in response to BCUC IR 1.212.2.1 and its evaluation schedule in response to BCUC IR 2.118.1.[798] The

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[793] Smith: T9, p. 1394, ll. 2 to 7. Based on a revised measure life of one year, the TRC for the program is 0.69, while the SCT declines is 1.58. This change has no material impact on the EEC portfolio as a whole. See Exhibit B-76, Undertaking No. 43.

[794] Exhibit B-25, Appendix 1, 2012-2013 EEC Plan, p. 15 and Exhibit B-67, BCUC IR 3.12.4.

[795] Exhibit B-67, BCUC IR 3.12.4; T9, p. 1396, l. 17 to p. 1398, l. 25.

[796] Exhibit B-67, BCUC IR 3.12.1, 3.12.4 and 3.12.6.1, including Attachment 6.1.

[797] Exhibit B-76, Undertaking No. 43.

[798] Exhibit B-9 and Exhibit B-17, respectively.

process, which has involved heavy reliance on third party experts[799], is in line with industry practice.[800]

509. There is no evidence to suggest that the International Performance Measurement and Verification Protocol, an excerpt of which was attached to a Commission Staff Witness Aid[801] is widely used in the industry, or that it is preferable to or different from the methods employed by the third party experts retained by the FEU.[802] Similarly, while the FEU's evaluations have many of the same objectives as those of the OEB guidelines,[803] and there is no evidence to suggest that evaluations must be done in accordance with the OEB guidelines to be reliable. The FEU have filed all of their evaluations to date in their EEC Annual Reports and no issues have been raised with those evaluations.

510. The FEU submit that they have employed a reasonable approach given the early stages of the EEC portfolio. The FEU are hiring an EM&V manager who will establish the appropriate EM&V framework.

(e) PSECA Program – Delta School District

511. The inquiry on the PSECA program focused on the fact that the FEU have committed $100,000 in EEC funds to the Delta School District for a project that the FEU is constructing and will own and operate.[804] The FEU's evidence on this funding was:

- First, the funding is being provided for boiler upgrades only, and not geothermal systems. The FEU do not have an EEC program aimed at geoexchange systems.

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[799] Smith: T9, p. 1408, ll. 22 to 25.

[800] Exhibit B-9, BCUC IR 1.192.4.3.

[801] Exhibit A2-7.

[802] Stout: T9, p. 1406, ll. 3 to 15. Ms. Smith indicated that two FEU was engaged in using the protocol. T9, p. 1403, ll. 3 to 9.

[803] Exhibit B-90, Undertaking No. 57.

[804] Smith: T9, p. 1413, l. 4 to p. 1415, l. 9. No other projects in the PSECA program are planned to be owned by FEU: T9, p. 1421, l. 26 to p. 1422, l. 2.

- Second, PSECA has a well-defined application process for qualifying applicants, and it was followed in the case of the Delta School District project. Ms. Smith described how once the application had passed the Climate Action Secretariat's screening the EEC group had the energy study reviewed by a third party and made incentive calculations based on the results of the study.[805]

- Third, this process took place independently of the TES group within the FEU. Ms. Smith confirmed that there was no communications between the EEC group at FEU and the Thermal Energy Services group.[806]

512. As with all EEC programs, before a customer receives an incentive amount, the customer must actually install the energy efficiency measure for which the customer is receiving the incentive. In cross-examination, a number of questions pointed to the fact that once customers receive the incentive that they can do whatever they want with the money. Whatever the customer does with the incentive dollars, the customer will have spent at least an equal and offsetting amount of dollars on the efficiency measure. Thus, as noted by Mr. Stout, whether the incentive dollars received goes towards the efficiency measure, or something else, is simply an accounting issue for the customer.[807] Moreover, it is difficult to see how the FEU could force a customer to attribute the incentive amount to the energy efficiency measure; the only important fact is that the customer must install the energy efficiency measure – and meet any other eligibility requirements of the program.

(f) Efficiency Partners Program

513. Included in the 2012-2013 EEC Plan is $500,000[808] per year to continue the Efficiency Partners program, which is part of the Residential Program Area. It is focused on developing and managing a contractor network to promote EEC programs and energy efficiency

[805] Smith: T8, p. 1343, l. 8 to p. 1344, l. 12.
[806] Smith: T8, p. 1345, l. 4 to p. 1346, l. 11.
[807] Smith, Bennett, and Stout: T9, p. 1416, l. 2 to p. 1418, l. 25.
[808] Exhibit B-25, Appendix 1, p. 17.

messaging.[809] These programs are common in DSM portfolios and, as stated in the text authority in the Commission staff's witness aid, "are a critical element of a successful suite of programs[810] In information requests and at the oral hearing, it was suggested that the FEU had inappropriately reinstated the Trade Relations Program Area, which the Commission had not accepted in the 2009 EEC Application. The FEU submit that the Efficiency Partners program is consistent with the 2009 EEC Application Decision.

514. The Commission's reason for not accepting the Trade Relations Program Area expenditures in the EEC Application Decision was that "the Trade Relations program area expenditures represent a significant duplication of the Residential and Commercial Energy Efficiency programs' non-incentive costs."[811] Thus, it was still anticipated that the type of work would be undertaken in the context of the Residential Program Area, such that the overall expenditure portfolio expenditure schedule did not need to be increased further to account for those activities. The intent of the Efficiency Partners program included in the 2012-2013 EEC Program is the same as the intent of the Trade Relations Program Area outlined in the original EEC Application,[812] but operating within the smaller approved expenditure schedule.

515. Ms. Smith's EEC Group had understood that although the FEU's EEC budget was reduced, they were free to undertake similar activities within the remaining approved budget.[813] The fact that they have acted in good faith is evident from the transparency of these steps in the context of reporting and stakeholder consultation. Although Ms. Smith did not recall on the stand,[814] the fact that the Trade Relations program was denied was brought to the attention of the Stakeholder Group. Included in Appendix F to the 2009 EEC Annual Report are the meeting minutes for the December 9, 2009 stakeholder meeting. These minutes state (at page 3) under a heading "Sarah Smith, Manager, Marketing & Energy Efficiency EEC Overview":

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[809] Smith: T9, p. 1431, ll. 9 to 21 and p. 1432, l. 23 to p. 1433, l. 5.
[810] Smith: T9, p. 1431, ll. 9 to 21; Exhibit A2-7, p. 13.
[811] Page 24 of that Decision.
[812] Exhibit B-67, BCUC IR 3.14.4
[813] Smith and Stout: T9, p. 1428, l. 7 to p. 1433, l. 6; Smith: T9, p. 1431, ll. 3 to 7.
[814] Smith: T9, p. 1432, ll. 11 to 13.

3) Innovative technologies and trade relations was denied

a. There are certain benefit/cost thresholds that have to pass

b. Innovative technologies have very long paybacks

c. Trade relations: funding was included in the non-incentive budgets that were put forward

d. We have incorporated trade relations in other areas of our EEC budget

516. The Energy Efficiency Partners program initiative was described in detail in the 2009 EEC Annual Report[815] and the 2010 EEC Annual Report[816] with specific reference to the Commission's decision regarding the Trade Relations Program Area. For instance, the 2009 EEC Annual Report stated at page 49:

> Efficiency Partners Program (Section 4.8.3): Formed to consolidate and enhance existing service and supplier relationships, to provide a delivery pathway for all EEC programs to customers. The EEC Decision ruling did not approve the discrete Trade Relations budget area put forward for these supporting activities as it was identified as a duplication of commercial and residential program delivery expenditure. The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the overall EEC TRC. The EEC Stakeholder Group has not identified any objection to this approach.

Similar wording was used in the 2010 EEC Annual Report.

517. The FEU submit their interpretation of the Commission's EEC Application Decision was accurate and reasonable and that the Companies have been transparent in their implementation of that program.

(g) Energy Specialists

518. The FEU's Energy Specialists Program is a program within the Commercial Program Area in the FEU's 2012-2013 EEC Plan.[817] The Energy Specialist positions are FEU

[815] Exhibit B-1, Application, Appendix K-3, Sections 4.8.3 and 5.13.4, pp. 49 and 122.
[816] Exhibit B-1, Application, Appendix K-4, sections 11.1.2, 11.2.2 and 11.3.2 at p. 221 and 245
[817] Exhibit B-25, Appendix 1, p. 44.

funded positions assigned to large commercial and institutional customers.[818] The Energy Specialists are employed by the customer and the $60,000 funding allotment is considered to be sufficient to partially cover the standard salary and benefits associated with this position.[819]

519. In the past, a major barrier to EEC program adoption by commercial and institutional customers has been facilitation of equipment installation and application administration on the part of the customer. Potential program participants are often lost because they do not have the resources available to implement the measures required for program participation, nor the time to go through the application process. The Energy Specialist program has been developed in collaboration with BC Hydro to address this issue.[820]

520. The Energy Specialist assists a BC Hydro-funded Energy Manager with completing a centralized project list and business case which captures the opportunities available within the organization's facilities to take advantage of the FEU's and BC Hydro's respective energy efficiency incentives and other opportunities for more efficient energy use. After project approval, the Energy Specialist facilitates the implementation of the new equipment as well as the application process for the incentives.[821] Individuals hired in the role of Energy Specialist will have appropriate skills and are in contact with the FEU's EEC staff who can provide any required support.[822]

521. The approach of having both the Energy Manager and the Energy Specialist working together is beneficial in three ways:

- First, the 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

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[818] Exhibit B-67, BCUC IR 3.19.1. The response to BCUC IR 1.217.2.1 (Exhibit B-9) provides a list of the 20 companies who were approved to have funded energy specialist positions.

[819] Exhibit B-67, BCUC IR 3.19.6.

[820] Exhibit B-9, BCUC IR 1.217.2 and Exhibit B-17, BCUC IR 2.128.1.

[821] Exhibit B-67, BCUC IR 3.9.3.

[822] Bennett: T9, p. 1446, l. 18 to p. 1447, l. 3. The required curriculum for Energy Specialists may be found in Exhibit B-81, Undertaking No. 48.

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.[823]

- Second, as explained by Ms. Smith, the energy specialists were placed with large commercial and institutional customers where BC Hydro already funded an energy manager because that means the customer is engaged in energy conservation. In such organizations, executive level engagement is important to being able to successfully execute EEC projects.[824]

- Third, the Energy Specialist is serving a need that is not being met by the BC Hydro Energy Manager, who is focused on electricity and does not have the capacity to address natural gas measures as well.[825]

522. Appropriate "checks and balances" are in place:

- Energy Specialists provide a report every three months to the FEU outlining the projects they have completed or are working on that increase participation in EEC programs or result in natural gas savings. This includes an estimate on the number of gigajoules projected to be saved for each project.[826] Energy savings associated with increased client organization participation in the FEU's EEC programs as a result of Energy Specialist activity are attributed to the appropriate FEU EEC program in order to prevent double-counting of these energy savings. The FEU are exploring how the energy savings achieved through each Energy Specialist placement could be verified and reported on.[827] In the

[823] Exhibit B-9, BCUC IR 1.217.2.

[824] Smith: T9, p. 1436, ll. 2 to 11.

[825] Exhibit B-9, BCUC IR 1.217.2.

[826] Exhibit B-17, BCUC IR 2.122.2. Further details on evaluation of Energy Specialist's performance is in Exhibit B-67, BCUC IR 3.19.5 to 3.19.7.1.

[827] Exhibit B-67, BCUC IR 3.19.2. Also see T9, p. 1450, ll. 2 to 20.

future, the program may also develop to provide certain energy savings targets for the Energy Specialists.[828]

- 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.[829]

(h) Energy Solutions Managers

523. Energy Solutions Manager positions are FEU's staff. The primary goal of the Energy Solutions Manager position is to increase participation in FEU EEC programs.[830] Ms. Smith explained:[831]

> So what -- if you can think of these roles as EEC sales roles, in essence. It's the role of the EEC ESM to go out and find commercial customers that have energy efficiency and conservation opportunities, and bring them into our programs, and kind of help them through. They're not managing a set number of accounts. They do things like put on lunch-and-learns, and presentations to groups of commercial customers that they would then subsequently work with to get them into our programs, and get them undertaking efficiency and conservation activity.

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[828] Smith and Bennett: T9, p. 1451, ll. 2 to 23.

[829] Exhibit B-9, BCUC IR 1.217.2.2.

[830] Exhibit B-80, Undertaking No. 47 provides the number of program participants generated by the two existing ESMs.

[831] Smith: T9, p. 1437, ll. 10 to 20.

For example, as set out in the 2012-2013 EEC Plan, the Energy Solution Managers will be undertaking the Medium-Large Education Sessions.[832]

524. As the Energy Solutions Manager is targeting participation in commercial programs for smaller and medium sized organizations, the budget for the Energy Solution Manager positions falls to the Commercial Program Area generally and the Energy Solutions Managers allocate time spent on working on customer participation in specific programs to those programs.[833] The FEU have three Energy Solution Manager positions, one for Vancouver Island, one for the Lower Mainland and one for the Interior. The Vancouver Island position is not currently filled.[834] The Energy Solution Managers are FEU employees.

525. The practice of having positions focused on sales activities dedicated to increasing participation in EEC programs is quite common. 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.[835]

526. The Energy Solutions Managers track their success based on the number and total incentive value of the EEC program applications that they source or assist with – energy savings are associated with the EEC programs and increased participants therein rather than with the Energy Solutions Manager roles.[836]

G. NEW PROGRAM AREAS

527. The FEU have proposed three new Program Areas: Furnace Scrap-it Program ($10 million per year), Solar Thermal ($4 million per year), and Thermal Energy for Schools ($11

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[832] Exhibit B-25, Appendix 1, p. 57.
[833] Exhibit B-67, BCUC IR 3.19.1.
[834] Smith: T9, p. 1433, l. 26 to p. 1434, l. 4.
[835] Exhibit B-9, BCUC IR 1.217.1.
[836] Exhibit B-17, BCUC IR 2.122.2.

million per year). In this section, the FEU highlight the evidence supporting the three new Program Areas. The three new Program Areas will only proceed if non-energy benefits are reflected in the economic screen, as they do not pass the TRC test. However, these Program Areas are beneficial and the Commission should approve activity in these Program Areas in conjunction with the adoption of the SCT.

(a) Furnace Scrap-It Program Area

528. The proposed EEC expenditures of $10 million per year for each of 2012 and 2013 for the Furnace Scrap-It Program will replace about 8,500 older furnaces annually with super-efficient furnaces. The Furnace Scrap-it Program, which is modeled on programs offered by other utilities,[837] represents an opportunity to create deep energy savings in the residential customer class. There is significant information on the record supporting the acceptance of this Program Area.

The Opportunity: Significant Potential Savings

529. The FEU's Conservation Potential Review shows that home heating represents the highest proportion of natural gas use by residential customers and the largest potential contributor to space heating energy savings is a furnace early retirement initiative.[838] Compared to other provinces across Canada, B.C. has a higher proportion of older furnaces and the lowest rate of adoption of high-efficiency furnaces.[839] It is estimated that there are 560,000 standard- and mid-efficiency furnaces in British Columbia. There is substantial evidence that shows that customers are keeping these old, but functioning, furnaces beyond their rated operating lives of approximately 20 years.[840] Owners are not upgrading them due to a poor payback period on the purchase of a new furnace (~20 years at current rates). It is estimated

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[837] Exhibit B-9, BCUC IR 1.202.2. Numerous jurisdictions currently offer incentives 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. Incentives range from $100 to $750. See this response for details.

[838] Exhibit B-1, Appendix K-2, Conservation Potential Review Summary. The full study is included in Exhibit B-9-1, Attachment 196.1.

[839] Exhibit B-9, BCUC IR 1.201.1 and 1.202.2.

[840] Exhibit B-9, BCUC IR 1.202.1.

that at the present rate of retirements it would take approximately 23 years for British Columbians to replace their inefficient furnaces.[841] The time lag in retirements, which is expected to be approximately 5-10 years, represents a lost opportunity for financial savings for homes and small businesses and GHG reductions, which could otherwise be captured through incentives.

530. Part of the potential savings associated with advancing standard and mid-efficiency furnace retirements have been targeted by the *LiveSmart BC: Efficiency Incentive Program,* which is expected to provide rebates for about 3,900 super-efficient furnaces in 2011. The Furnace Scrap-It program would provide an incentive for early replacement of an additional 8,500 furnaces per year (some of which might be administered through the LiveSmart BC program as well). The FEU's Furnace Scrap-It Program incentives would accelerate the replacement of British Columbia's inefficient furnaces by about 50 percent.[842] The net result is short-term energy cost savings for customers and GHG emission reductions.[843]

Program Structure and Budget

531. The Furnace Scrap-It program provides incentives for early replacement of working, inefficient gas furnaces. The installed efficient equipment is assumed to have an AFUE of 96 percent and the assumed baseline for the existing equipment 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.[844]

532. The preliminary budget for the program is set out in the following table.[845] Further explanation of inputs follows.[846]

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[841] In 2009, the total furnace shipments to BC were 36,000, although a sizable proportion of those are for new construction. Assuming two-thirds of those furnaces shipped were replacement, it would take 23 years for British Columbians to replace their inefficient furnaces.

[842] Exhibit B-1, Appendix K-1, p. 13

[843] Exhibit B-1, Appendix K-1, p. 13.

[844] Exhibit B-9, BCUC IR 1.189.2.

[845] Exhibit B-9, BCUC IR 1.202.5.

[846] Exhibit B-9, BCUC IR 1.202.5.

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**

Forecast Participation Levels

533. Based on past program participation levels, effective marketing, and partnerships with trade allies, LiveSmartBC and other electric utilities, the proposed Furnace Scrap-It program target of 8,500 participants annually is achievable. In support of this forecast:[847]

- In the 2008-2009 ENERGY STAR® Heating System Upgrade program the FEU provided 8,429 rebates for furnaces purchased between September 2008 and December 31, 2009, and an additional 9,137 rebates in partnership with LiveSmartBC.

- Discussions with industry partners at the 2010 CPR Achievable Potential workshop suggested 2012 estimates of 6,028 units as the lower limit and 16,423 units as the upper limit.

- In the 2008 REUS study, almost 25% of the FEU's customers suggested that their furnaces were more than 20 years old, while the 8,500 unit target represents only 1% of the FEU's residential households.

[847] Exhibit B-9, BCUC IR 1.202.1.

- The FEU will be engaging in effective marketing and collaborative partnerships. Since expanded EEC program funding was approved in 2009, the FEU's residential program offering as a whole has more visibility in the market, making new program introductions more likely to get greater traction at the outset. The establishment of the FEU contractor program and a proposed contractor incentive will provide greater buy-in from trade allies to help promote the program to customers. The FEU will collaborate with heating system manufacturers to find ways to integrate the offer into their marketing strategies through co-operative advertising opportunities. Partnerships with LiveSmart BC and the electric utilities will further drive program participation.

534. Program design has not yet been completed and further consultation with relevant stakeholders will provide better insights into the actual program uptake and program design considerations. The program will be designed to be available to the most deserving customer segments through targeted marketing and program rules to minimize free riders and establish stringent controls and governance.[848] For instance, 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.[849]

Participant Incentive Levels Are Appropriate

535. The Furnace Scrap-It Program is based on incentives of $1,000, which aligns with the provincial and federal government rebate programs as follows:[850]

[848] Exhibit B-9, BCUC IR 1.202.3.
[849] Exhibit B-9, BCUC IR 1.202.3.
[850] Exhibit B-9, BCUC IR 1.202.5.

- In the 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.

536. Experience from these government rebate programs suggests that they were effective in driving heating system upgrades. 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.[851]

Other Elements of the Program Area

537. The response to BCUC IR 1.202.7 describes other elements of the Program Area, including: the contractor incentive ($100 per 8,500 contractors for a total of $850,000); marketing ($250,000 in 2012 and $100,000 in 2013) that could include communications partnerships with LiveSmartBC, municipal governments, furnace manufacturers and dealers to help drive program awareness); and product stewardship program ($185,000 for a combination of incentives, program management, and outreach to contractors and customers).[852] The FEU are also continuing to investigate the possibility of offering funding under this Program Area through LiveSmartBC.[853] The FEU would provide further details to the EEC stakeholder group as this program is developed further.

[851] Exhibit B-9, BCUC IR 1.202.5.

[852] Exhibit B-9, BCUC IR 1.202.3 and 1.202.7.

[853] Exhibit B-9, BCUC IR 1.202.6

Forecast Energy Savings and Cost-Effectiveness

538. The annual energy savings for the 2012 and 2013 Furnace Scrap-It program are estimated to be 106,417 GJ 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). The NPV of savings over the lifetime of the measure is over 1 million GJ. Two years of cumulative savings approach the Upper Achievable Potential estimate of 369,000 GJ outlined in the Conservation Potential Review, representing significant energy and GHG emissions reductions for the Province.[854]

539. The estimated savings are presented in the table below.[855]

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			

540. The Furnace Scrap-It program by itself does not pass the TRC but passes the FEU's proposed SCT.[856] Specifically, the TRC test result is 0.56, while under the FEU's proposed

[854] Exhibit B-9, BCUC IR 1.202.4.

[855] Exhibit B-9, BCUC IR 1.202.3 and 1.202.4.

[856] Exhibit B-9, BCUC IR 1.201.1.

SCT the result is 1.18.[857] A variety of possible SCT results have also been presented by the FEU in response to information requests.[858] There are significant non-energy benefits associated with the Furnace Scrap-it program and the FEU submit that the SCT is appropriate for this program. Further, when considered in conjunction with FEU's existing Programs Areas, the Furnace Scrap-it program would be part of an overall cost-effective portfolio of EEC programs using the SCT.[859]

Conclusion on Furnace Scrap-it Program

541. The FEU submit that the Furnace Scrap-it program is supported by strong evidence of potential energy savings. The Furnace Scrap-it Program is similar to other programs that the FEU have implemented in the past and is the most developed of its proposed new Program Areas.[860] The FEU submit that the $10 million in expenditures for each of 2012 and 2013 should be accepted by the Commission in conjunction with the adoption of the SCT.

(b) Solar Thermal Program Area

542. The Application requested a budget of $8 million over the next 2 years ($4 million for 2012 and $4 million for 2013) for a new Solar Thermal Program Area. Given the early stages of development of these programs, however, the FEU have agreed that a prorated amount for 2012 would be appropriate to allow the FEU to continue program design and pursue implementation of the programs for 2013.[861] The Solar Thermal Program Area offers energy source reductions from natural gas to solar for domestic hot water for residential and commercial applications and solar for space conditioning preheat for commercial and industrial applications.[862] The programs also support the government's climate action goals and policies focused on fostering the development of market-ready technologies that promote energy

[857] Exhibit B-9, BCUC IR 1.201.1.
[858] Exhibit B-9, BCUC IR 1.201.1.1. Exhibit B-17, BCUC IR 2.107.2.
[859] Exhibit B-69, BCSEA IR 3.26.3.
[860] Stout: T9, p. 1461, ll. 9 to 17; Smith: T9, p. 1490, ll. 15 to 24.
[861] Smith: T9, p. 1487, l. 19 to p. 1488, l. 4.
[862] Exhibit B-9, BCUC IR 1.203.2.

conservation and efficiency and the use of renewable resources.[863] The FEU submit, for the reasons set out below, that the Solar Thermal Program Area has merit and should be accepted in conjunction with the adoption of the SCT.

The Need For Sustained Activity to Develop Solar Thermal

543. Solar thermal equipment comes with a high upfront capital cost, which most customers are not willing to absorb for the energy bill savings and other benefits expected.[864] Past solar thermal initiatives have been successful in promoting the adoption of solar thermal energy through the use of incentives. It is essential for market transformation to continue the positive momentum that has been gained over the last few years through those programs, developing its market share, associated jobs and economic benefits.[865]

544. Incentive programs that had been offered by PSECA, Natural Resources Canada's EcoEnergy for Renewable Heat program, and SolarBC's Residential program, were time limited and have come to an end as planned.[866] However, the results of those programs, discussed below, suggest a strong demand for solar thermal within the residential, commercial and industrial sectors:

- 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 further capital funding

[863] Exhibit B-1,Appendix K-1, pp. 13-14.
[864] Exhibit B-1, Appendix K-1, pp. 13 to 14.
[865] Exhibit B-1, Appendix K-1, pp. 13 to 14.
[866] Exhibit B-9, BCUC IR 1.203.2.

from the Government of B.C. has not been allocated for the PSECA program. Therefore, PSECA solar thermal incentives are no longer available.[867]

- The SolarBC Residential program offered incentives to encourage 540 households across BC to install solar hot water which resulted in 4,353 GJ saved every year and annual GHG emission reductions of 94 tonnes of carbon dioxide. 240 or (54 percent) of all the residential installations since 2008 occurred in 2010. NRCan's EcoEnergy for Renewable Heat program funded over $20.5 million for 1,268 commercial solar thermal hot water systems and industrial solar for space conditioning preheat systems throughout Canada. 514 or (41 percent) of all the commercial and industrial installations since 2007 occurred in 2010. Both the SolarBC Residential and NRCan's EcoEnergy for Renewable Heat program indicate an active industry interest for solar thermal and resulted in an increased uptake percentage each year that those programs were available.[868]

545. Budgets at other levels of government (provincial and municipal) are inadequate to provide the kind of scale needed to capitalize on this interest for solar thermal and carry on the market transformation effort.[869] FortisBC Inc. (electric) and LiveSmartBC both offer incentives for solar thermal;[870] however, the budgets of those programs are inadequate on their own to provide the kind of scale needed to start the market transformation effort for solar thermal domestic hot water. If the Program Area is approved, the FEU may collaborate with the existing LiveSmartBC program to offer an additional incentive for solar thermal hot water for residential customers.[871]

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[867] Exhibit B-9, BCUC IR 1.203.2.1.

[868] Exhibit B-1, Appendix K-1, pp. 13 to 14.

[869] Exhibit B-1, Appendix K-1, pp. 13 to 14.

[870] 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.

[871] Exhibit B-9, BCUC IR 1.203.5.

546. The Solar Thermal Program Area has a goal of starting to achieve some economies of scale.[872] 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.[873] The FEU therefore submit that there is a need in the marketplace for a program to provide incentives for the adoption of solar thermal technologies.

Program Details

547. While much work remains to be done in designing the Solar Thermal programs, the FEU submit that the high-level planning to date is sufficient to show that the programs have merit. The FEU anticipate the 2012 and 2013 funding to be broken down into three solar programs: Solar Thermal Hot Water – Residential (50%); Solar Thermal Hot Water – Commercial (37.5%); and Solar Thermal Air – Commercial/Industrial (12.5%).[874] Each program is described below.

- **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.[875]

[872] Exhibit B-9, BCUC IR 1.201.4

[873] Exhibit B-9, BCUC IR 1.203.4.

[874] The original budget allocation to each of these three programs is shown in Exhibit B-9, BCUC IR 1.203.1, but the 2012 budget must now be prorated.

[875] Exhibit B-9, BCUC IR 1.189.2.

- **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.[876]

- **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.[877]

548. Natural gas would be used as a backup fuel source for all 3 of these programs.[878]

549. Some of the critical components needed to guide the development and feasibility of future Solar Thermal 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.[879] 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

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[876] Exhibit B-9, BCUC IR 1.189.2.
[877] Exhibit B-9, BCUC IR 1.189.2.
[878] Exhibit B-9, BCUC IR 1.203.1
[879] Exhibit B-9, BCUC IR 1.203.3.2.

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 that it 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 in Q2 of 2012 to gather data to estimate the level of energy savings associated with the installation of solar thermal.[880]

550. 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.[881]

551. The FEU plan to establish further details surrounding program design, delivery and controls pending funding envelope approval.[882]

Cost-Effectiveness Results

552. Individual solar thermal programs fail the TRC test and SCT due to the high incremental cost of solar equipment, and the prevailing low cost of natural gas. TRC and SCT results are as follows:[883]

Program	Project Type	TRC	SCT
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

[880] Exhibit B-9, BCUC IR 1.203.3.2.

[881] Exhibit B-9, BCUC IR 1.203.1.1.

[882] Exhibit B-9, BCUC IR 1.203.1.

[883] Exhibit B-9, BCUC IR 1.201.1. A variety of possible SCT (or modified TRC test) results have also been presented by the FEU in response to information requests: Exhibit B-9, BCUC IR 1.201.1.1. Exhibit B-17, BCUC IR 2.107.2. The Ratepayer Impact Measure results for the individual programs 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: Exhibit B-9, BCUC IR 1.203.4.

553. However, Solar Thermal programs are "technology innovation programs" under the DSM Regulation. A "technology innovation program" is a program to develop a technology that is (a) not commonly used in British Columbia, and (b) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy.[884] The cost-effectiveness of a "technology innovation program" must be judged at a portfolio level pursuant to section 4(4) of the DSM Regulation. On a portfolio basis, solar thermal programs will be able to proceed in a material fashion only if the proposed SCT or another modified TRC test that recognizes non-energy benefits is used to assess cost-effectiveness. The FEU's proposed SCT would effectively capture such non-energy benefits as job creation, and environmental attributes that are not reflected in the TRC test.[885]

554. The FEU submit that using the SCT on a portfolio basis is appropriate given the longer term benefits of solar thermal market transformation. Mr. Plunkett provided extensive evidence supporting the pursuit of market transformation programs despite low cost-effectiveness results. For instance:[886]

> Several considerations can lead DSM program administrators to promote efficiency measures in their programs despite standard cost-effectiveness calculations indicating that the present worth of their societal resource benefits do not exceed current cost estimates. Cost-effectiveness calculations are static snapshots, predicated on point estimates of the measure's cost, as well as its performance and the future value of its energy savings over its expected lifetime. All these numbers are predictions of expected values based on engineering and economic judgment about future efficiency and energy market conditions. They are subject to wide variation over time, the more so the further into the future the estimates are applied. It is not practical to constantly update rapidly-changing cost estimates and change course on the basis of ever-changing cost-effectiveness calculations. The estimates can be applied accurately over a fairly wide range, but not necessarily precisely to a single point – such as a benefit/cost ratio of 1.0.
>
> . . .

[884] "Technology innovation program" is defined in the DSM Regulation, Section 1.

[885] Exhibit B-1, Appendix K-1, pp. 13 to 14.

[886] Exhibit C4-4, BCSEA Evidence, pp. 19 to 23.

> Static measure cost-effectiveness calculations under the standard definition of the TRC do not consider the dynamic influence programs are designed to have on future costs of high-efficiency measures with low current market penetration. The history of DSM programs in North America is replete with successful efforts to capitalize on economies of scale in manufacturing and distribution to drive down future costs of emerging efficiency technologies by stimulating consumer demand for high-efficiency products and equipment. Sustained national, regional and even state-level efforts have increased demand for expensive high-efficiency products by offering financial incentives to consumers and/or suppliers. The resulting increases in volume led to major cost reductions, which in turn led to faster and higher market penetration over time.

Conclusion on Solar Thermal

555. The Solar Thermal programs will provide incentives to adopt technologies that will provide significant energy savings and GHG reductions with the ultimate goal of achieving market transformation. The DSM Regulation has recognized the value of such market transformation programs by requiring them to be evaluated on a portfolio basis. Employing the SCT on a portfolio basis so as to permit material funding of solar thermal program development and incentives in 2012 and 2013 is appropriate and should be accepted based on the evidence filed.

(c) Thermal Energy for Schools Program Area

556. The FEU does not currently offer any program targeting the adoption of thermal energy, although boiler upgrades as part of a district energy system may qualify under an existing program. The proposed Program Area fills this void to encourage schools to adopt efficient thermal energy systems, with resulting energy and non-energy benefits. Incentives will be provided to the qualifying customer directly, without regard to the identity of a project partner. The evidence demonstrates that this Program Area is in the public interest.

Opportunity Addressed By Thermal Energy for Schools Program Area

557. The need to replace worn out equipment (such as central boilers, individual rooftop air-handling units, and ancillary equipment) is urgent for many schools across BC, but the incremental costs are a major barrier for schools to proceed with replacing their energy

systems. In addition, schools are challenged with compliance with government legislation to become carbon neutral via reduction in carbon emissions and/or through the purchase of carbon offsets. Faced with limited budgets and constraints on capital and debt, the ability of school districts to achieve these goals is limited.[887]

Program Area Details

558. The FEU initially proposed a $22 million incentive program for geoexchange and energy efficiency retrofits in up to 260 schools over two years. However, given the early stages of development of these programs, the FEU have agreed that a prorated amount for 2012 would be appropriate to allow the FEU to continue program design and pursue implementation of the program for 2013.[888] The Thermal Energy for Schools program will provide capital incentives for state-of-the-art low carbon energy systems such as geoexchange systems, high-efficiency boiler upgrades, as well as educational energy monitoring equipment. These state-of-the-art low carbon energy systems continue to incorporate natural gas as a critical energy input, whether as the primary component or as a back-up and peaking energy source.[889] These systems replace the existing heating and cooling system for elementary and secondary schools, which will vary by site.[890]

559. The assumed measure life is 20 years and the typical incremental cost is expected to be approximately $525,000 per site. The FEU expect to process fewer than 200 rebates annually.[891]

Cost-Effectiveness Results and Broader Benefits

560. The Thermal Energy Services for Schools Program Area does not pass the TRC test, but the non-energy benefits considered under the SCT make two of the three individual

[887] Exhibit B-1, Appendix K-1, pp. 14 to 15. Exhibit B-9, BCUC IR 1.204.3.1.
[888] Smith: T9, p. 1490, ll. 4 to 12.
[889] Exhibit B-1, Appendix K-1, pp. 14 to 15.
[890] Exhibit B-9, BCUC IR 1.189.2.
[891] Exhibit B-9, BCUC IR 1.189.2.

programs cost effective. Under the EEC portfolio approach, the Thermal Energy Services for Schools EEC program should all proceed.

561. The Thermal Energy Services 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.[892] TRC and SCT Results for examples of these projects are as follows:[893]

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

562. All three examples fail 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. The Elementary School project resulted in a negative value TRC, which should be viewed as non-passing benefit-cost ratios.[894] The negative result is due to this example project having an increased electric usage that exceeds the natural gas savings, resulting in a negative benefit-cost ratio.[895] However, the analyses show that all secondary and average projects are individually cost-effective using the FEU's proposed SCT, with a 3 percent discount rate, a 30 percent deemed adder, and based on the biomethane ceiling price.[896]

563. There are a number of non-energy benefits associated with this Program Area that would be captured using the 30 percent proposed deemed adder for non-energy benefits in the SCT.[897] The scope of this Program Area has been restricted to schools to address a clearly defined financial need, to provide benefits that target BC families, and to provide

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[892] Exhibit B-9, BCUC IR 1.201.1.

[893] Exhibit B-9, BCUC IR 1.201.1.

[894] Exhibit B-9, BCUC IR 1.189.2.

[895] Exhibit B-9, BCUC IR 1.201.1.

[896] Exhibit B-9, BCUC IR 1.189.2. A variety of possible SCT results have also been presented by the FEU in response to information requests: Exhibit B-9, BCUC IR 1.201.1.1. Exhibit B-17, BCUC IR 2.107.2.

[897] Exhibit B-1, Appendix K-1, pp. 14 to 15.

important educational and training opportunities about energy efficiency and environmental stewardship for present and future generations of students.[898] 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; GHG reductions; and, reductions for the schools in required emission offset purchases.[899]

564. As a "technology innovation program" the cost-effectiveness of the Thermal Energy for Schools program should be evaluated on a portfolio basis, not on an individual program or Program Area basis.[900] Under the FEU's proposed SCT, the Thermal Energy for Schools program is part of an overall cost-effective portfolio.[901]

Independent of Project Ownership Model

565. 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 school 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.[902]

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[898] Exhibit B-1, Appendix K-1, pp. 14 to 15.

[899] Exhibit B-9, BCUC IR 1.204.1.1.

[900] Section 4(4)."Technology innovation program" is defined in the DSM Regulation, Section 1. Exhibit B-9, BCUC IR 1.204.3.1.

[901] Exhibit B-69, BCSEA IR 3.26.3.

[902] Exhibit B-9, BCUC IR 1.204.3.

Summary: Thermal Energy for Schools

566. The evidence is that the Thermal Energy for Schools Program Area meets a defined need in elementary and secondary schools in the Province and will result in energy savings and other significant benefits. Under the FEU's proposed SCT, the Thermal Energy for Schools Program Area is part of an overall cost-effective portfolio.

(d) Conclusion on New Program Areas

567. The FEU recognize that its new Program Areas need further development and program design. For this reason, Ms. Smith agreed that a reasonable approach would be for the Commission to ask that the FEU come back for acceptance of expenditures for these programs when it is has more detailed programs developed,[903] with the caveat that any further regulatory process should be minimized in the interests of all stakeholders.[904] The FEU submit, however, that if the Commission were to approve the FEU's proposed SCT or other modified TRC, that it would be preferable to accept expenditures for the new Program Areas for 2012 and 2013 (with reduced expenditures in 2012). As discussed below, the FEU must manage the portfolio to the cost-effectiveness guidelines, and the results will be available to stakeholders and the Commission.

H. ACCOUNTABILITY MECHANISMS AND ADMINISTRATIVE EFFICIENCY

568. The FEU's proposals for 2012 and 2013 are based on the accountability mechanisms that were approved by the Commission in the 2008 EEC Decision[905] and discussed in the 2010-2011 RRA and the NGV-EEC proceeding filing.[906] The following sections elaborate on the Commission-approved EEC framework and discuss possible variations to it. The rules governing how the FEU develop and fund EEC programs should be transparent, administratively efficient, and allow for sufficient Commission oversight. The FEU submit that the current approach strikes the right balance.

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[903] Smith and Bennett: T9, p. 1551, l. 20 to p. 1552, l. 12.

[904] Smith and Bennett: T9, p. 1551, l. 20 to p. 1552, l. 12.

[905] Order G-36-09, Reasons for Decision, p. 42. See also Exhibit B-1, Appendix K-1, pp. 4-7.

[906] Exhibit B-9, BCUC IR 1.205.1.

(a) The Approved Framework

569. In the present Application, the FEU have put forward a total spending envelope for approval, with the scope of that spending envelope to be defined by the Program Areas identified in the Application. This request is consistent with the key elements of the existing EEC framework that resulted from the EEC Application Decision.

570. In the EEC Application, the Companies had requested that the Commission approve the overall expenditure level, rather than approving the funding levels by program area, or by individual program initiative. The Commission had approved this approach, indicating (at page 42):

> …while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

571. The EEC Decision, at page 41, summarized what the FEU had proposed regarding accountability mechanisms:

> In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. 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.

572. The Commission noted in the EEC Decision that interveners supported this approach (at page 41):

> BCSEA-BCSC states that they: ". . . support this approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20) [Emphasis added.]

573. The Commission then accepted these accountability mechanisms stating:[907]

> The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

574. The Commission Panel also directed "that the annual EEC Report include . . . 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."[908]

575. This is the process that the FEU have followed to date. The Annual Reports for 2009 and 2010 are included in the Application. The minutes of stakeholder consultation meetings are also included in the evidence. By and large, the current process has worked well, and the questions in this proceeding about how the portfolio is being administered are isolated. Nevertheless, a good outcome of this proceeding for all concerned would be for the Commission to elaborate on the ground rules to be applied prospectively under the current approach.

(b) The Existing Stakeholder Engagement Process is Appropriate

576. In cross-examination, Commission counsel suggested that "insomuch as there is no terms of reference at this point, and the stakeholder committee is consultative only" it gave

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[907] Order G-36-09, Reasons for Decision, p. 42. See also Exhibit B-1, Appendix K-1, pp. 4-7.

[908] Order G-36-09, Reasons for Decision, p. 42.

the FEU "a carte blanche, as it were, in terms of the decision-making on how to use the EEC funds."[909] FEU's witnesses disagreed, citing a number of reasons:

- Ms. Smith indicated that the FEU manage a portfolio of activity to a set of cost-effectiveness guidelines and provide with Commission with very extensive compliance reporting on that activity.[910] The FEU are ultimately accountable for the results of the EEC programs.[911]

- The FEU provide details on its EEC programs and take input from stakeholders through the stakeholder group.[912] Mr. Bennett emphasized that the FEU have good business reasons to listen to its stakeholders because their ongoing support is important: "…we're going to be back before the Commission asking for extension to programs, and we can't be ignoring the needs, the advice of our stakeholders."[913]

577. The stakeholder engagement process is necessarily consultative, not consensus based or binding.[914] The FEU are responsible for the management of its business and, under the *Utilities Commission Act*, it is the Commission that accepts or rejects EEC expenditure schedules and it is the FEU that are accountable for the prudence of their expenditures. The Commission cannot delegate its authority to accept or reject expenditures and the FEU cannot responsibly hand over the management of its EEC portfolio to stakeholders who are not accountable for the outcomes.

578. A number of Staff exhibits and questions from Commission counsel addressed whether a more rigorous stakeholder engagement process was appropriate. Ms. Smith was

[909] Fulton: T9, p. 1523, l. 26 to p. 1524, l. 4.
[910] Smith: T9, p. 1524, ll. 12 to 20.
[911] Smith and Bennett: T9, p. 1524, l. 25 to p. 1526, l. 1.
[912] Stout: T9, p. 1524, ll. 5 to 11.
[913] Bennett: T9, p. 1475, ll. 2 to 5.
[914] Stout: T9, p. 1521, l. 8 to p. 1522, l. 8.

open to different processes,[915] but observed that the FEU's current stakeholder engagement process is consistent others in the Province such as BC Hydro's.[916]

579. Further, a more elaborate stakeholder process, without clear justification, is not necessarily better for customers. The stakeholder engagement process is one of three oversight mechanisms around EEC spending, with the other two being the process for accepting expenditure schedules and annual reporting. The level of scrutiny of EEC programs in this proceeding has been significant. Preparing Annual Reports is not a trivial exercise for the EEC group; the last Report took 3 months to prepare.[917] All of these processes cost money. Adding to the stakeholder consultation processes without obtaining efficiencies elsewhere in these processes will come with greater cost to customers.[918] Time spent on undertaking these reviews is time not spent by the EEC Group on delivering programs. In short, the FEU are committed to transparency and to participating in the processes that the Commission establishes, but submit that if there is going to be more involved stakeholder consultation then care should be taken to realize regulatory efficiencies elsewhere.[919]

(c) Summary on Accountability Mechanisms and Administrative Efficiency

580. The FEU submit that the current accountability processes are effective and provides a reasonable level of flexibility for the FEU to able to manage its portfolio in a cost-effective manner.

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[915] Smith: T9, p. 1535, ll. 13 to 18.
[916] Smith: T9, p. 1520, ll. 12 to 21.
[917] Smith and Bennett: T9, p. 1549, ll. 10 to 17.
[918] Stout: T9, p. 1533, l. 6 to p. 1534, l. 9.
[919] Stout: T9, p. 1533, l. 6 to p. 1534, l. 9.

PART TWELVE: CONCLUSION

581. The FEU submit, for the reasons articulated in this Submission, that the evidence confirms:

- the proposed delivery rates are just and reasonable; and
- the proposed financial treatment, the overall envelope of EEC activity, the proposed SCT, and the existing oversight mechanisms, are appropriate.

The FEU therefore respectfully submit that the Commission should approve the orders as specified in the attached updated Draft Order.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: December 2, 2011

[original signed by Matthew Ghikas]

Matthew Ghikas

Counsel for the FortisBC Energy Utilities

Dated: December 2, 2011

[original signed by Chris Bystrom]

Chris Bystrom

Counsel for the FortisBC Energy Utilities

APPENDIX A

DRAFT ORDER

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by the FortisBC Energy Utilities
(comprising FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area,
FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.)
for Approval of 2012 and 2013 Natural Gas Rates

BEFORE: D.A. Cote, Panel Chair/Commissioner
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

O R D E R

WHEREAS:

A. On May 4, 2011, the FortisBC Energy Utilities (FEU or the Companies) filed an Application (Exhibit B-1) for their Revenue Requirements for FortisBC Energy Inc. (FEI), the Fort Nelson Service Area of FEI (Fort Nelson), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Energy (Vancouver Island) Inc. (FEVI), and for approval of interim and permanent natural gas delivery rates effective January 1, 2012 and permanent rates effective January 1, 2013, pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the Act), with any variance between 2012 interim rates and permanent rates to be refunded to or collected from customers by way of a rate rider following the approval of 2012 permanent rates;

B. FEI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 5.59 percent effective January 1, 2012 and a further 6.29 percent permanent increase effective January 1, 2013;

C. FEI further seeks approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes for 2012, and approval of the cost allocation to Thermal Energy Services (previously referred to as Alternative Energy Services) for 2012 and 2013 as set out in the Application;

D. Fort Nelson region seeks, among other things, approval pursuant to sections 59 to 61 of the Act, no change to delivery rates effective January 1, 2012 and a 1.32 percent delivery rate increase effective January 1, 2013;

E. Fort Nelson also seeks approval of the RSAM rider for applicable rate classes for 2012 as set out in the Application;

F. FEW seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 5.02 percent effective January 1, 2012 and a further 6.54 percent permanent increase effective January 1, 2013;

G. FEW also seeks approval of the RSAM rider for applicable rate classes for 2012 as set out in the Application;

H. FEVI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction, to maintain current natural gas rates for all customers other than those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012. FEVI proposes to utilize the surplus that will exist in the Rate Stabilization Deferral Account (RSDA) to allow for rates to remain unchanged for 2013;

I. FEVI further seeks approval of its schedule of demand and commodity charges, forecast gross O&M expenditures and, pursuant to section 2.10 of the Special Direction, its forecast cost of service, forecast capital expenditures, and forecast revenue;

J. The FEU seek, among other things, approvals including: allocation of costs for shared services between the Companies; discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts; changes to depreciation rates; and pursuant to section 44.2 of the Act, for Energy Efficiency and Conservation (EEC) expenditures;

K. On May 6, 2011, the Commission issued Order G-81-11 establishing Regulatory Timetable for the review of the Application as well as setting dates for a Workshop and a Procedural Conference and Orders L-42-11 and L-45-11 Amended the Regulatory Timetable;

L. A Workshop took place on May 18, 2011 and a Procedural Conference took place on June 15, 2011;

M. On July 19, 2011, the FEU filed an Evidentiary Update (Exhibit B-11) and on September 12, 2011 the FEU filed a second Evidentiary Update (Exhibit B-21);

N. On October 3, 2011, the Commission began an oral public hearing to review the 2012/2013 RRA Application (the Oral Public Hearing);

O. At the Oral Public Hearing, the FEU filed revised financial schedules for FEVI (Exhibit B-52) and Fort Nelson (Exhibit B-66);

P. The Commission has reviewed and considered the Application, the evidence and the submissions and has determined that the Application should be approved.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to sections 59 to 61 of the *Utilities Commission Act* (the Act), the following approvals are granted for FEI subject to the updating of financial schedules with the opening balance of net plant-in-service and rate base deferral accounts and the agreed to reduction in the forecast 2012 and 2013 additions to the EEC rate base deferral account:
    a. Approval of permanent delivery rates for all non-bypass customers effective January 1, 2012 and January 1, 2013, representing an increase of 5.59 percent for 2012 and an additional 6.29 percent for 2013. The increase is to be applied to the delivery charge and the basic charge will remain at 2011 levels.
    b. Approval of the RSAM rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2U, 2X, 3, 3U, 3X and 23 effective January 1, 2012 of ($0.032)/GJ as set out in Section 3.4.3 of the Application (the 2013 RSAM rider will be adjusted with the FEI Fourth Quarter 2012 Gas Cost filing).
    c. Approval of the 2012 and 2013 cost allocation to Thermal Energy Services (formerly Alternative Energy Services) as set out in Section 5.3.18 and Appendix G of the Application.
    d. Approval of the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for 2012 and 2013 as set out in Section 5.5 of the Application.
    e. Approval of the 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 set out in Section 5.5 of the Application effective January 1, 2012.
2. The following approvals are granted for FEVI subject to the updating of financial schedules with the opening balance of net plant-in-service and rate base deferral accounts and the agreed to reduction in the forecast 2012 and 2013 additions to the EEC rate base deferral account:
    a. Pursuant to sections 59 to 61 of the Act and section 2.1 of the Vancouver Island Natural Gas Pipeline Agreement Special Direction (the "Special Direction"), approval of permanent rates for FEVI for 2012 and for 2013 for Core Market sales and transportation customers, other than customers who have specified rates in their transportation service agreements, at the same level as 2011 rates.
    b. Pursuant to section 2.10(a)(i) of the Special Direction, approval of FEVI's forecast Cost of Service for 2012 and 2013 as set out in Schedules 5 and 6 of Undertaking No. 24 (Exhibit B-52).
    c. Pursuant to section 2.10(a)(i) of the Special Direction, approval of FEVI's forecast capital expenditures for 2012 and 2013, as set out in Section 6.2 of the Application.
    d. Pursuant to section 2.10(a)(ii) of the Special Direction, approval of FEVI's forecast revenue for 2012 and 2013, based on its proposed rates, as set out in Schedules 11 and 12 of Undertaking No. 24 (Exhibit B-52).
    e. Pursuant to sections 59 to 61 of the Act, approval of the forecast gross O&M expenditures for 2012 of $36.117 million and for 2013 of $36.232 million.

f. Pursuant to sections 59 to 61 of the Act, approval of the 2012 and 2013 cost of gas as set out in Schedules 5 and 6 of Undertaking No. 24 (Exhibit B-52), and discontinuation of the quarterly reporting of gas costs for FEVI as set out in Sections 5.2 and 6.3 of the Application effective the first quarter of 2012.

g. Pursuant to sections 59 to 61 of the Act, approval of the difference between the net revenues received and the actual cost of service, excluding O&M variances from forecast, to be allocated to the RSDA for 2012 and 2013, as set out in Section 3.4.2 of the Application.

3. Pursuant to sections 59 to 61 of the Act, the following approvals are granted for FEW subject to the updating of financial schedules with the opening balance of net plant-in-service and rate base deferral accounts and the agreed to reduction in the forecast 2012 and 2013 additions to the EEC rate base deferral account:

   a. Approval of permanent delivery rates for all customers effective January 1, 2012 and January 1, 2013, representing an increase of 5.02 percent for 2012 and an additional 6.54 percent for 2013.The increase is to be applied to the delivery charge, holding the basic charge at 2011 levels.

   b. Approval of the RSAM rider for customers served under FEW Rate Schedules SGS 1/2, LGS 1, LGS 2 and LGS 3 effective January 1, 2012 of $0.524/GJ as set out in Section 3.4.3 of the Application (the 2013 RSAM rider will be adjusted with the FEW Fourth Quarter 2012 Gas Cost filing).

4. Pursuant to sections 59 to 61 of the Act, the following approvals are granted for Fort Nelson subject to the updating of financial schedules with the opening balance of net plant-in-service and rate base deferral accounts and the agreed to reduction in the forecast 2012 and 2013 additions to the EEC rate base deferral account:

   a. Approval of permanent delivery rates for all customers effective January 1, 2012 and January 1, 2013, representing no change for 2012 and an increase of 1.32 percent for 2013. The changes are to be applied to the delivery charge and the minimum monthly service charge.

   b. Approval of the RSAM rider, and corresponding changes to the minimum monthly service charge, for customers served under Fort Nelson Rate Schedules 1, 2.1, 2.2 and 25 effective January 1, 2012 of ($0.011)/GJ as set out in Section 3.4.3 of the Application (the 2013 RSAM rider will be adjusted with the Fort Nelson Fourth Quarter 2012 Gas Cost filing).

5. Pursuant to sections 59-61 of the Act, the following approvals are granted for FEI, FEVI, FEW and Fort Nelson to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012:

   a. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and each of FEI, FEVI and FEW, as reflected in the Corporate Services Agreements between FortisBC Energy Holdings Inc. and FEI, FEVI and FEW as described in section 5.3.18 of the Application.

   b. Approval of the allocation of costs for shared services between FEI and FEVI, as described in section.

   c. Approval of the allocation of costs for shared services between FEI and FEW, as described in section 5.3.18 of the Application.

d. Approval to allow for charges between regulated entities to be based on a fully loaded benefits and concessions charge and to not include overheads or a facilities fee, as described in section 5.3.18 of the Application.

e. Approval of the consolidated Core Market Administration Expense (for FEI, FEVI and FEW), and allocation percentages, as set out in section 5.2 of the Application.

f. Approval of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI, FEVI, FEW and Fort Nelson all as set out in section 6.2, Appendix G and Exhibits B-11 and B-21 to the Application and summarized in the following table.

Type of Change	Account	Company	Reference
New Account	Compliance with Emissions Regulations	FEU	Section 6.3.2.3; Additions and Amortization period TBD
	Customer Service Variance Account	FEU	Section 6.3.3.10; Additions and Amortization period TBD
	2012-2013 Revenue Requirement Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2012, allocated to FEU based on average customers
	Long Term Resource Plan Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2013, allocated to FEU based on average customers
	Gas Assets Records Project	FEU	Section 6.3.5.11; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	BCOneCall Project	FEU	Section 6.3.5.12; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	Residual Delivery Rate Riders	FEI	Section 6.3.6.3 and BCUC Order No. G-195-11; amortization period of 1 year commencing January 1, 2012
	Muskwa River Crossing 2011	FN	July 19 Evidentiary Update (Exhibit B-11);the 2011 revenues to be refunded to customers in 2012 due to the delay in implementation of the Muskwa River Crossing Project
	NGV Incentives	FEI	September 12 Evidentiary Update (Exhibit B-21) Transfer of NGV Incentives provided to customers for 2010 and 2011 from the EEC deferral account to this new rate base account; disposition to be determined

Type of Change	Account	Company	Reference
	AES Inquiry	FEI	September 12 Evidentiary Update (Exhibit B-21); amortization period of 5 years commencing January 1, 2012
	US GAAP Transitional Account	FEI, FEVI	Section 3.2.2; a one-time deferral account to capture the unamortized pension and OPEB transitional obligation amortized by plan over EARSL
	US GAAP Pension and OPEB Funded Status Account	FEI, FEVI	Section 3.2.2; an ongoing deferral account to capture the annual pension and OPEB funded status adjustment
	Fort Nelson 2012 Revenue Surplus Account	FN	A rate base deferral account to record the 2012 revenue surplus for return to customers in 2013
	US GAAP Uncertain Tax Positions	FEI, FEVI	Section 3.2.2; an ongoing non-rate base deferral account to capture any differences that arise from the implementation of US GAAP Financial Accounting Standards Board Interpretation No. 48
Amortization Period Change-New or Modified	Revenue Stabilization Account Mechanism	FEW	Section 6.3.1.3; recovery through Rate Rider 5, 3 year recovery period consistent with FEI and FN, commencing January 1, 2012
	Gas in Storage Interest	FEI	Section 6.3.1.4; 3 year amortization period, commencing January 1, 2012
	Property Tax Variance Account	FEW, FN	Section 6.3.3.1; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Tax Variance Account	FEW	Section 6.3.3.6; 1 year amortization period, commencing January 1, 2012
	Vancouver Island HST Implementation	FEVI	Section 6.3.3.7; 1 year amortization period, commencing January 1, 2012
	Victoria Regional Centre CPCN	FEVI	Section 6.3.4.3; 1 year amortization period, commencing January 1, 2012
	Deferred Removal Costs	FEU	Section 6.3.5.5; 2 year amortization period, commencing January 1, 2012
	2010-2011 Customer Service O&M and Cost of Service	FEU	Section 6.3.5.9; 8 year amortization period, commencing January 1, 2012

Type of Change	Account	Company	Reference
Other	Energy Efficiency and Conservation	FEU	Section 6.3.2.1; 1. Combined EEC rate base deferral account additions of $15.0 million in 2012 and $15.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period; 2. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and FEW on an average customer basis; 3. The creation of the EEC rate base deferral account for FEW, with additions included on a net-of-tax basis and amortized in rates over a ten year period; 4. The creation of the EEC Incentive non-rate base deferral account for FEI attracting AFUDC, to capture the remaining portion of the EEC costs as incurred and allocated by FEI to each utility based on the actual spend in the service area of each utility in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.
	CNG and LNG Service Costs and Recoveries	FEI	Section 6.3.2.6; inclusion of variations from the revenue forecast pertaining to Rate Schedule 16
	Property Tax Variance Account	FEW	Section 6.3.3.1; include the forecast balance of the existing Propane Plant Property Tax Deferral account in the Property Tax Variance account
	Tax Variance Account	FEI	Section 6.3.3.6; include the balance of the existing LILO reassessment costs deferral into the Tax Variance Account
	Gains and Losses on Asset Disposition	FEU	Section 6.3.5.6; 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; 20 year amortization period, commencing January 1, 2012
	Biomethane Variance Account	FEI	Appendix G, 2.1; classification of this account as non-rate base
Discontinuance	Residential Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012
	Commercial Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012

Type of Change	Account	Company	Reference
	IFRS Transitional Account	FEI, FEVI	Section 3.2.2; discontinuation of this account effective January 1, 2012

g. Approval of changes to the following accounting policies to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012:

   i. The depreciation and amortization rates and the creation of a separate sub account (474.02) to record future additions to Distribution Systems Meters/Regulator Installations with depreciation expense for this sub account calculated using a whole life rate, set out in Sections 5.4.2 and 5.4.5 of the Application.

   ii. The negative salvage rates and the treatment of negative salvage as set out in Section 5.4.3 of the Application.

   iii. Modification to the approved Lead Lag days with the removal of the GST and PST lead days and the insertion of the proposed HST and REC lead days as set out in Section 6.1 of the Application.

6. With respect to Energy Efficiency and Conservation ("EEC") expenditures, the Commission orders as follows:

   a. Pursuant to section 44.2(a) of the Act, the Commission accepts the following EEC expenditure schedules for the FEU to be spent on the EEC program areas described in Appendix K-1 of the Application, including the expansion of the interruptible industrial Program Area eligibility to customers of FEVI and all EEC program eligibility to customers of FEW and Fort Nelson:

      i. $13.35 million for FEI for each of 2012 and 2013;

      ii. $1.5 million for FEVI for each of 2012 and 2013;

      iii. $0.15 million for FEW for each of 2012 and 2013;

      iv. An additional $49.5 million for FEI for each of 2012 and 2013 to be spent in the service areas of FEI, FEVI, FEW and Fort Nelson.

   b. Pursuant to sections 59 to 61 of the Act, the Commission approves the treatment of EEC costs in accordance with the EEC deferral accounts as described in the table of deferral accounts above in section 6.

   c. With respect to assessing EEC expenditures, the Commission directs FEU pursuant to section 43 of the Act to continue to file an EEC Annual Report in which it will:

      1. Continue to evaluate EEC expenditures as an overall portfolio.

      2. Continue to report on funding transfers between approved program areas.

      3. Continue to evaluate EEC expenditures on the basis previously approved by the Commission, except with respect to the following changes:

a. The overall portfolio should have a benefit-cost result of 1.0 or greater, using a Societal Cost Test consisting of the following three modifications to the current benefit-cost analysis:

   i. Use of a social discount rate of 3 percent, rather than the Companies' weighted average cost of capital;

   ii. Use of the ceiling price for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas, for all EEC programs;

   iii. Use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity.

b. The inclusion of spillover in the calculation of the Net-to-Gross Ratio when estimating program effects.

7. **DATED** at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

APPENDIX B

BOOK OF AUTHORITIES

An Application by FortisBC Energy Utilities

[COMPRISING FORTISBC ENERGY INC., FORTISBC ENERGY INC., FORT NELSON SERVICE AREA, FORTISBC ENERGY (WHISTLER) INC., AND FORTISBC ENERGY (VANCOUVER ISLAND) INC.]

2012 AND 2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES

BOOK OF AUTHORITIES OF FORTISBC ENERGY UTILITIES (FOR SUBMISSION)

DECEMBER 2, 2011

INDEX

1. Decision, In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements, March 13, 2009 (BCUC Order No. G-16-09) (pages 31-39)

2. Decision, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Return on Equity Capital Structure, December 16, 2009 (BCUC Order No. G-158-09) (pages 6-15)

3. Enbridge Gas Distribution Inc. v. Ontario (Energy Board), [2006] O.J. No. 1355

4. ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board), 2005 ABCA 122

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

F2009 AND F2010 REVENUE REQUIREMENTS

DECISION

March 13, 2009

Before:

L.A. O'Hara, Panel Chair and Commissioner
R.J. Milbourne, Commissioner
A.A. Rhodes, Commissioner

determinations in this Decision based on the evidence and submissions before it, in a manner consistent with the overall scheme of the *Act* and HC2.

2.1.3 The Prudency Test

It was common ground among the parties to the hearing that the following paragraphs from the Ontario Court of Appeal decision in *Enbridge Gas Distribution Inc. v. Ontario(Energy Board)* [2006] O.J. No. 1355, 41 Admin L.R. (4^{th})69(C.A.) ("*Enbridge Gas*") represent the law on the proper approach to an examination of the prudency of a utility's expenses:

> **10** The approach of the OEB to the "prudence" inquiry is captured in the following extract from its reasons:
>
> > While the parties described it in somewhat varying terms, in the Board's view they were in substantial agreement on the general approach the Board should take to reviewing the prudence of a utility's decision.
> >
> > The Board agrees that a review of prudence involves the following:
> >
> > * Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
> >
> > * To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
> >
> > * Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
> >
> > * Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.
>
> **11** Neither the Divisional Court nor either party to this appeal takes issue with the correctness of the above quoted passage from the OEB's reasons. The "prudence" inquiry described by the Board has two stages. At the first stage,

> the decision of Enbridge is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision. At the second stage of the inquiry, reached only if the presumption of prudence is overcome, Enbridge must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, Enbridge at the time it made the decision.
>
> **12** In the above quoted extract from its reasons, the OEB expressly alluded to the limited role played by hindsight. Hindsight, that is knowledge of facts relevant to the prudence of the business decision gained after the decision was made, could not be used at the second stage of the "prudence" inquiry to determine the ultimate question of whether the decision was prudent. Those facts could, however, be taken into consideration at the first stage in determining whether the presumption of prudence had been rebutted.

BC Hydro submits that "[t]he correct approach to "prudency" has three elements: (1) a rebuttable presumption that utility decisions, and the resulting costs are prudent; (2) hindsight may not be used to assess whether decisions were prudent but may be used to rebut the presumption; and (3) decisions that are the subject of a prudency inquiry are prudent if they were objectively reasonable." It cited *Enbridge Gas* and the Alberta Court of Appeal decision in *ATCO Gas and Pipelines Ltd. v. Alberta Energy and Utilities Board* 2005 CarswellAlta 582, 2005 ABCA 122 (*"ATCO 2005"*) in support of its position (BC Hydro Argument, pp. 20-24). Based on those authorities, BC Hydro asserts that it is apparent that the scope of the prudency test "applies to all management decisions, and their cost consequences, that flow from management's obligations to manage the affairs of the company [and] all decisions with respect to expenditures ... whether capital or operating," noting, however, that while "it does not apply to all elements in this proceeding such as, for example, amortization of regulatory accounts", it means that "[a]s is suggested in *Hemlock [Valley]*, the Commission is obliged to set rates that allow for recovery of the revenue requirement as between customer classes, and over time...." (BC Hydro Argument, p. 26).

No Intervenor takes a contrary position in respect of the prudency aspect of expenditures that reflected BC Hydro's past decisions, or that the appropriate standard is that reflected in *Enbridge* Gas, and crystallized in *ATCO 2005* as the "two-part test." In essence, the onus to rebut the presumption of prudency is borne by the party seeking to impugn the decision of the utility, but once rebutted, the objective test of the utility's decision is the reasonableness of that decision in light of the facts known to it at the time the decision was made (BC Hydro Argument, p. 22).

However, in regard to other decisions that "prospectively" forecast expenses in the test period, BCOAPO submits that the presumption of prudency on the part of BC Hydro does not apply, and that the onus for establishing the reasonableness of such expenditures rests with BC Hydro (BCOAPO Argument, pp. 4-5). In reply, BC Hydro submits that no authority is cited for the BCOAPO view, that there is no basis for it in the authorities cited by BC Hydro, and that the position of the BCOAPO is "simply incorrect" (BC Hydro Reply, p. 6).

The JIESC makes a similar point to that of BCOAPO, submitting that BC Hydro bears the burden of proof that the requested rate and corollary relief ought to be granted (JIESC Argument, p. 4).

In reply, BC Hydro revisits the authorities cited in its Final Argument, and asserts that "BC Hydro's management has exercised its legal responsibilities in establishing capital and operating budgets for the F2009 and F2010 fiscal periods that will allow BC Hydro to meet its service obligations. All such decisions get the benefit of the presumption of prudence. The fact that some expenditures arising from management decision-making will happen at a future time does not make such decisions any less the responsibility of BC Hydro, or any more the responsibility of the Commission" (BC Hydro Reply, p.6).

Given the parties divergent positions on the scope of the Commission Panel's discretion in reviewing BC Hydro's forecasts and planned expenditures in its RRA, and the extent to which a presumption of prudency accrued to BC Hydro in respect of its decisions in determining its revenue requirements and the differing views as to which party bore the "onus of proof" in respect of rebutting, or establishing, that presumption of prudency, pursuant to item 3 of Exhibit A-26, the Commission Panel invited submissions from the parties in respect of a hypothesis that BC Hydro could be perceived as claiming "immunity" from Commission amendment or variation of any of its planned or forecast expenditures in the absence of a finding of imprudence on BC Hydro's part.

In its opening submissions on item 2, BC Hydro had distinguished between externally forecast components and its planned expenditure components of its revenue requirements. In particular, BC Hydro distinguished forecasted expenditures arising from the world at large, which it exemplified as matters such as interest rates and wholesale market prices for electricity, from operating costs, which it states are planned expenditures arising from its budgeting processes. On the former, BC Hydro states that it bears the balance of persuasion, and the Commission must satisfy itself on the evidence what, for example, interest rates should be for the purpose of setting BC Hydro's revenue requirement. It is only on the latter, which BC Hydro states reflect its managements' legal obligation to determine what is necessary to meet its obligations to provide service, that BC Hydro asserts that it receives a presumption of prudency (T15: 2689-2691).

BC Hydro further distinguished the planned expenditure components by identifying the basis on which they could be "forecasts" based on expected vs. approved spending in current but incomplete fiscal years (T15: 2090). BC Hydro summarized its position as being that not all of its forecast expenditures receive the benefit of the presumption of prudency, only those that result from the planning obligations on BC Hydro to meet its legal obligation to serve (T15: 2692). BC Hydro also clarified that *Hemlock Valley* was not cited by it in respect of any prudency related matters *per se*, but was tabled as authority for BC Hydro's position that the Commission may not trade-off other factors against BC Hydro's right to the opportunity to earn its allowed rate of return (T15: 2692).

BC Hydro rejected the notion that it was seeking immunity from review of its planned expenditures and stated that its "question" was "how are they to be reviewed and what is the burden that Hydro bears with respect to demonstrating that its planned expenditures ought to be recovered in rates" (T15: 2705).

BCOAPO characterized BC Hydro's position as "a direct challenge to the very notion of meaningful rate regulation," in that it meant that "the Commission must defer to the utility's word as to how much money it wants to spend on operations in the coming period unless the Commission or another party can meet an evidentiary onus to demonstrate that the utility's revenue should be less than applied for", characterizing that position as "a total reversal of the well established onus that rests on the shoulders of a utility to justify its applied-for revenue requirement." BCOAPO noted that if the burden were the other way around, strictly speaking in terms of a fair hearing, all that would be required for the utility to do is say "here's what we're entitled to", and if the evidentiary burden is on the Intervenors, we are the ones who would somehow have to muster all the evidence that probes into the reasonableness of those proposed expenditures." BCOAPO pointed to the Commission's publication "Understanding Utility Regulation: A Participants' Guide to the British Columbia Utilities Commission ("Participants' Guide")" and its guidance at page 26 " ... the burden of proof is on the utility to justify its application to the Commission" and, "[F]or this reason, the utility is expected to include written evidence necessary to support its application to the Commission." BCOAPO further referred to the statement at page 38 of the Participants' Guide: "When the utility applies for an increase in rates to be charged to its customers, it must justify the revenue requirement that supports the request for an increase" (T15: 2731-2734).

BCOAPO stated that "BC Hydro's effort to reverse the onus in establishing its approved prospective operational costs would presumptively insert the utility's managers above the judgment of the regulator and strip much of the substance out of the *Act* and the Commission itself." As authority for its position BCOAPO referenced a November 2008 Alberta Utilities Board ("AUB") Decision 2008-113 in respect of the 2008-2009 General Rate Application of ATCO Gas (*"ATCO 2008"*), noting at the outset that the statutory scheme in Alberta stipulates, as a matter of law, that the onus rests on the utility to justify rate increases, but that, in BCOAPO's view, was insufficient to distinguish the case from the BC Hydro situation (T15: 2739). BCOAPO characterized the Alberta statutory scheme as nothing more than a codification of a well understood regulatory principle.

BCOAPO quoted from page 13 of *ATCO 2008* where the AUB discussed both retrospective and prospective expenditures. In terms of past expenditure performance, the AUB stated: "Because the utility's rates in the base year and other past years had been approved by regulation as just and reasonable and because the quality of service of the utility had also been regulated, the interests of customers in receiving acceptable service at reasonable prices were protected by regulation. In that environment, any decisions made by the utility within those rates and quality guidelines can be presumed to be prudent insofar as the balance between the monopoly power of the utility and its customers is present." In terms of future expenditures the AUB stated: "Operating expenses and capital expenditures forecast by a utility to be incurred in the test years cannot be presumed to be prudent because the balance between customer and company interests that would be present in a competitive market is simply not present and no regulatory examination has yet occurred to counter balance the monopoly power of the utility" (T15: 2742-2743).

BCOAPO submitted that both "common sense" and the principle of the line of reasoning by the AUB in *ATCO 2008* are confirmatory of the legislative intent of the *Act,* and that BC Hydro's position seeking to reverse the onus with respect to an application for approval of forecast expenditures to be recovered in rates should be rejected (T15: 2744).

The JIESC, COPE, CEC, and IPPBC generally concurred with the essence of BCOAPO's arguments on this issue.

Terasen submitted that the AUB in *ATCO 2008* clearly relied on the statutory scheme in making its determinations, and that in B.C., the *Act* puts no such statutory obligation on a utility to justify its expenditures. Terasen further submitted that what might be in the Participants' Guide did not establish such a burden. Terasen argues that there is no such burden on either the applicant or the intervenor(s) because there is a statutory obligation on the Commission to set rates that are just and reasonable, which obliges the Commission to listen to all the evidence, apply its judgment to the evidence, and to establish the rates (T15: 2785-2786).

Terasen characterizes BC Hydro's position as saying that "the rates it has sought in its application, and in particular the operating expenses it has sought in its application must be accepted unless the Commission rules that its forecasts involve expenditures that the Commission determines are imprudent." Terasen does not support BC Hydro's position, on the basis that the *Act* does not establish a test of imprudency in determining rates in a revenue requirement proceeding, rather it adopts a standard of reasonableness and justness as a test of rates. In summary, Terasen submitted that rates should be determined on the basis of the evidence in the proceeding, that forecast expenditures should not be disallowed capriciously, and that the Commission should not substitute its views on how the utility should be operated for those of the management of the company. Terasen expresses particular concern that the imposition of a prudency test in respect of forecasts could lead to increasingly complex and burdensome revenue requirements proceedings (T15: 2795-2798).

Terasen also argued that it was appropriate to subject prior actions taken by utility management that become the subject of a retrospective review to a prudency test, and referenced the AUB's reasoning in the *ATCO 2008* decision in that regard (T15: 2799).

In reply, BC Hydro states its understanding of Terasen's position as being that "management's obligation is to decide what those (operating) expenses should be, and that they may not be simply substituted for by a different number by the Commission to achieve other objectives because that would then undermine the ability of the utility to earn a return on its investment." BC Hydro notes that the large volume of evidence on the record virtually all came from BC Hydro, and that unless the Commission found that evidence wanting, most of its revenue requirement is likely to be accepted so "the issue [of prudency] is really around the edges" (T15: 2814).

BC Hydro points out that in its view the presumption of prudency with respect to its decisions, whether retrospective, or prospective, did not mean that they could not be set aside, or that the onus had shifted, or that the evidentiary burden had shifted, and, at the end of the day "[it] isn't perhaps as big a deal as its being made out to be." BC Hydro describes the issue in terms of, having filed its application, what are the questions raised by intervenors, Commission Staff and the Commission Panel that perhaps rebut the presumption, asserting that this was not a wholesale change in the way things had been done, and was fundamentally unlikely to affect the substance of the Commissions decision "except for here or there on a few particular cost issues" (T15: 2815-2816).

BC Hydro also addresses the *ATCO 2008* decision, distinguishing it from BC Hydro's position, noting firstly that it dealt with a forecast of debenture rates, a matter typical of those to which BC Hydro said the presumption of prudency did not, in its view, apply. Secondly, BC Hydro points to the AUB legislative framework, which references a regulation requiring that a determination be made by the Commission as to the prudent costs incurred by a gas distributor, which discretion would be frustrated if the presumption of prudence claimed by ATCO prevailed, and submits that that is not the case with respect to BC Hydro's revenue requirement in this proceeding. BC Hydro contrasts the Alberta regulatory scheme with that of [HC2], noting that nothing in [HC2] section 4 fetters the Commission's ability to look at every single element of BC Hydro's cost structure (T15: 2826-2828).

In summary, BC Hydro states its position as "[it] does bear a burden of persuasion with respect to its case generally. But with respect to certain of its decisions [...] which relate primarily to the decisions of management, it gets a presumption of prudence. It's a rebuttable presumption, and that's all it gets. And that doesn't shift the burden in the way that the Commission here seems to assume it does" (T15: 2830-2831). In an exchange with the Panel Chair, BC Hydro stated that its claimed presumption of prudency would be rebutted in any specific instance arising from the evidence in the proceeding by its witness' acknowledgement that the matter at issue could be accomplished in some alternative way that would be more efficient, regardless of the prudency test that the Commission applies or doesn't apply (T15: 2833-2834).

2.1.4 Commission Determination in Respect of Item 3 of Exhibit A-26

Having considered the extensive submissions and authorities cited by the parties, the Commission Panel determines that in the case of reviewing the cost consequences of BC Hydro's past management decisions a rebuttable presumption of prudency is relevant, and that the two-part test arising from the *Enbridge Gas* and *ATCO 2005* decisions applies.

In its review of BC Hydro's planned and forecast expenditures for the test period the Commission Panel finds that, as suggested by Terasen, BC Hydro's presumption of prudency has little, if any, relevance to the matters reviewed, and accordingly makes its determinations in this Decision

based on the evidence before it in a manner consistent with the overall scheme of the *Act* and HC2.

2.2 Other Matters

BC Hydro raised two matters in its Argument in which it advanced the proposition that the Commission's discretion was lawfully fettered. Firstly, in respect of the consideration of trend and benchmarking information in the Commission Panel's determinations, BC Hydro stated that "it would be unlawful for the Commission to reach any conclusions with respect to the Application on the basis of trend and benchmarking information, and the ratios in response to the Commission Panel IR (Exhibit B-33-A), without regard to BC Hydro's decisions that resulted in those trends and ratios." While it cites no statutory or legal authority for its position, it submits that "the Commission should base its final orders on the reasons for the changes to BC Hydro's cost structure over time, and the prudence of BC Hydro's decisions that resulted in the changes" (BC Hydro Argument, p. 30).

Secondly, in respect of consideration of the Commission Panel accepting final rate schedules for filing under subsection 61(1) of the *Act*, BC Hydro said that such an approach, despite its attractiveness, would be unlawful. It cites as statutory authority for its position the new subsection 44.2(2) of the amended *Act*, which precludes the Commission from so doing "'to the extent that the amendment ... is for the purpose of recovering [DSM] expenditures' unless the DSM expenditures have been filed and accepted by the Commission – which will not happen until the 2008 LTAP is resolved" BC Hydro Argument, p. 129).

The above matters are dealt with at Section 4.10 and Section 5.5.6 of this Decision, respectively.

As well, BCOAPO in its Argument, in respect of the Commission Panel's requests for argument on certain matters (Exhibit B-24), takes the position that "The Commission has no jurisdiction to order BC Hydro to change its insurance arrangements in any way." While it cites no statutory authority for its position, it submits that "[t]he Commission's only purchase point on this question is in

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.
TERASEN GAS (WHISTLER) INC.

AND

RETURN ON EQUITY AND CAPITAL STRUCTURE

DECISION

December 16, 2009

BEFORE:

Anthony J. Pullman, Commissioner/Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

2.0 JURISDICTION AND THE FAIR RETURN STANDARD

In this Section the following issues are addressed:

- What are the interests of the parties and the Commission's obligations under the *Act*?
- What is the fair return standard and how does the Commission Panel determine whether it is currently being met?
- Are US data relevant in this determination?
- If the fair return standard is not being met for TGI, how should the Commission Panel proceed to ensure that it is met?

2.1 The Interests of the Parties and the Commission's Obligations under the *Act*

Terasen states that the impact of its Application is to increase TGI's revenue requirements by $44.9 million, an increase of approximately 3.6 percent ($38 per year) to the annual bill of a TGI residential customer in the Lower Mainland. Further, Terasen states that the impact can be broken down as follows:

Company	Impact of 1% Equity Increase ($000)	Impact of .25% ROE Increase ($000)
TGI	$2,400	$3,100
TGVI	N/A	$800(1)

(1) Terasen notes that the revenue requirement increase for TGVI may not necessarily translate to a customer rate impact because of the soft cap mechanism.

(Source: Exhibit B-3, BCUC 3.5, 3.6)

The Intervenors take exception to the timing and amount of the increases being sought. Counsel for JIESC characterizes them as "worse than unreasonable, they are blatantly opportunistic and must be denied" (T2:23). The British Columbia Old Age Pensioners Organization *et al.* ("BCOAPO") submits that, "these increases would occur despite the Applicant...providing the exact same service

quality and reliability as it currently does. In other words, it represents money for nothing."
(BCOAPO Argument, para 1)

It is clear that Terasen has a significant interest in receiving the relief sought in the Application and the Intervenors have a significant stake in minimizing it.

Terasen has made the Application pursuant to sections 59 and 60 of the *Act*. Those sections are quoted in their entirety in Appendix C to this Decision.

Under section 60(1)(b) of the *Act*, when setting a rate the Commission must have due regard to the setting of a rate that:

(i) is not unjust or unreasonable within the meaning of section 59;

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands; and

(iii) encourages public utilities to increase efficiency, reduce costs, and enhance performance.

Under section 59(5) of the *Act* a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; and

(c) unjust and unreasonable for any other reason.

The Industrial Customer Group ("ICG") submits that the *Act* requires the Commission to balance the interests of the parties and set a just and reasonable rate that provides the utility with a fair return on the rate base. ICG submits that section 59 of the *Act* explicitly requires the Commission to consider the rates from the customer perspective, specifically whether the proposed rate is fair and reasonable for the nature and quality of the service. Part of that consideration must include the economic impact of the rate for the service on customers. The Commission's primary responsibility is to regulate rates as a surrogate for competition and to keep rates within the reasonableness one would expect in a properly functioning market. Considering the customer perspective is one-half of the balance equation in a regulated environment. When acting as the surrogate for competition, the Commission cannot and must not protect Terasen from all competitive risk by raising the ROE at the expense of customers. Doing so would ignore the interest of the customers who are captive to the monopoly. (ICG Argument, p. 5)

Terasen submits that the following quotation from page eight of the Commission's 2006 Decision on Terasen's ROE, Capital Structure and the AAM ("2006 ROE Decision") correctly sets out that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital:

> "The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital." (Terasen Reply, para 6)

2.2 The Fair Return Standard

Terasen cites the TQM Decision, which summarizes the fair return standard at page 6:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)." (Terasen Argument, para 12)

Terasen and the Intervenors address the fair return standard from the perspectives of the return on invested capital of the utility, the return on the equity, the level of financial risk, the creditworthiness and financial integrity of the utility, and, on the premium paid over book value for TI by Fortis Inc. in 2007.

In her evidence, Ms. McShane states: "The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes." (Exhibit B-1, Tab 3, p. 3)

Ms. McShane addresses the maintenance of the creditworthiness and financial integrity of the utility and opines that the capital structure of TGI, in conjunction with the returns allowed on its sources of capital, should provide the basis for a stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that Terasen should be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. (Exhibit B-1, Tab 3, p.26; Terasen Argument, para 101)

The Intervenors do not disagree with the A rating but observe that Terasen has enjoyed an A rating for many years. (JIESC Argument, p. 12)

JIESC points out that:

- in 2007, Fortis Inc. "purchased the TGI equity (sic) paying a premium of $900 million for it. A premium over book value upon which Terasen is not permitted to allow either a debt or equity return. This amounts to 1.7 times the equity value";
- in February 2009, a time when "debt markets were still recovering from the 2008 financial turmoil" TGI was able to issue $100 million debt; and

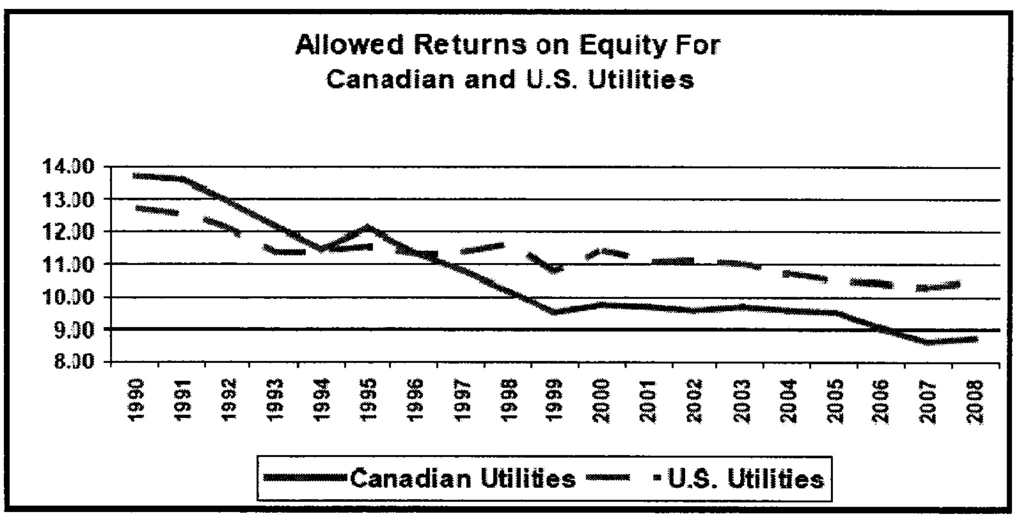
- in May 2009 TGI's bond rating was confirmed at "A" by both DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's"). (JIESC Argument, p. 13)

Terasen points out that TGI's Moody's rating actually is A3 and submits that the rating is "only one notch above BBB+, which is a level at which even Dr. Booth believes TGI should not be." (Terasen Reply, para 82)

Terasen also addresses the issue of acquisition premia and refers the Commission to its 2006 ROE Decision where the Commission addressed the acquisition of TI by Kinder Morgan Inc. ("KMI") and stated at page 13: "There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination." (Terasen Reply, para 94)

2.3 The Applicability of US Data in Determining the Fair Return Standard

Terasen provides the following chart to compare the differences between ROEs allowed to electric and natural gas utilities by state regulatory agencies in the US with the ROEs allowed by Canadian regulatory agencies:



(Exhibit B-1, p. 14)

Terasen includes two reports as appendices to the Application:

i) a report sponsored by the Ontario Energy Board ("OEB") entitled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" dated June 14, 2007 and authored by Concentric Energy Advisors ("CEA") (the "CEA Report"); and

ii) a report sponsored by the Canadian Gas Association ("CGA") entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis" authored by National Economic Research Associates, Inc ("NERA") dated February 2008 (the "NERA Report").

The CEA Report made ten conclusions, of which three are germane:

1. "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing US companies or other provinces' utilities that would explain the difference in ROEs";

2. "(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the US, do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus US utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE proceedings in Canada and the US, these differences are determined to be negligible"; and

3. "(9) As a result of the interplay between the Canadian and US markets, Canadian utilities compete for capital essentially on the same basis as utilities in the US." (Exhibit B-1, Appendix 3)

The NERA Report concludes, in part:

"We find that the regulatory institutions and customs for setting regulated prices for investor owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions…"

> "We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences in Figure 1 [A Figure showing the Allowed Return Differential (Canada - US) for Gas Distribution Utilities in the period 1992-2007]." (Exhibit B-1, Appendix 4, Executive Summary)

Terasen filed the evidence of Mr. Donald A. Carmichael, a financial consultant and advisor, as Tab 2 to the Application. His opinion evidence addresses the integration of markets and competition for capital. Mr Carmichael states that the globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past, and points to the fact that:

- many of Canada's largest institutional investors have become major players on international stock markets and non-Canadian private equity situations;
- the market in Canada for the new issuance of foreign bonds and debentures has grown rapidly reflecting Canadian lenders' desire to diversify their portfolios with new issuers and to achieve higher returns than those available from domestic issuers; and
- the funding requirements for announced infrastructure projects in Canada will be significant and will directly compete with debt and equity financing for utilities. (Exhibit B-1, Tab 2, pp. 32-35)

Terasen submits that restrictions on foreign investments by Canadians have been removed and that competition for capital is not constrained by provincial or national borders. Canadian and international capital markets have become more integrated than in the past. Large amounts of capital are required for infrastructure projects in Canada and around the world. Terasen submits that TGI's capital structure and return on equity must be comparable to other companies of similar risk to allow it to successfully compete for capital. (Terasen Argument, para 19)

The NEB addressed the issue in the TQM Decision where it stated:

> "In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis.
>
> A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. ...As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place." (TQM Decision, pp. 66-67)

In addition, the AUC stated that it would, "review the market based return data available on the record in respect of the sample US utility proxy groups and employ this data in its CAPM [Capital Asset Pricing Model] and DCF [Discounted Cash Flow] determinations." (AUC Decision 2009-216, para 205)

Terasen submits that global competition for capital means that TGI's capital structure must be comparable to its North American peers. In Terasen's view, the TQM Decision recognizes this capital requirement, which should also be recognized by the Commission. (Terasen Argument, para 95)

In the 2006 ROE Decision the Commission addressed what it saw as the two issues of relying on US data to establish appropriate capital structures and ROEs for utilities. On the first issue (i.e. that there are opportunities for Canadian investors to commit capital globally) the Commission noted that Canadian investors faced a considerable foreign exchange risk when investing and was not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

On the second issue (i.e. that in measuring the risk premium it is necessary to look beyond Canadian data) the Commission stated that it was prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when those data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data give unreliable results; based on the fact that the US and Canadian economy and capital markets were closely integrated. (2006 ROE Decision, p. 50)

BCOAPO submits that "select US utilities...are not useful in determining comparable returns and comparable risk." (BCOAPO Argument, para 7)

Dr. Laurence Booth provided a written opinion of the fair return for TGI on behalf of the Intervenors. In his evidence, Dr. Booth states: "The message from these....disasters of US regulatory policy [i.e. the bankruptcy of Pacific Gas and Electric; the Enron and WorldCom frauds; the failure of US entities such as Lehman Brothers; and 'stock market disasters represented by pipelines like Duke Energy'] is that the US is not Canada, no matter what American witnesses before the Canadian regulatory tribunals seem to think. Regulation in the US has followed a different path to that in Canada, as is patently obvious to anyone who looks at its results. Drawing any insights from how investors perceive US utilities (or banks) given this different regulatory approach in my judgment is of very little value. I would strongly advise Canadian regulatory tribunals to ignore the advice of experts, who have US experience in mind when they from (sic) their judgments. Instead, they should focus on Canadian solutions that have worked rather than US solutions that have resulted in disaster." (Exhibit C11-5, p. 103)

Terasen submits that the evidence demonstrates that Dr. Booth's attempt to use Enron and WorldCom as examples of light-handed US utility regulation fails; neither Enron nor WorldCom were US utilities or utility holding companies, and Dr. Booth's citation of Enron, WorldCom, or Duke Energy fails to support the argument that the Commission should not consider US utilities in its determination of a fair return on equity. (Terasen Argument, para 352-53)

Commission Determination

In view of the fact that no party took issue with the articulation of the fair return standard by the NEB in the TQM Decision, the Commission Panel endorses it. It also agrees with Terasen that the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody's.

As for the Intervenors' submissions that this is not the time for a rate increase, and ICG's submission that the Commission must balance the requirements of customers with those of Terasen, the Commission Panel adopts the Commission's statement in the 2006 ROE Decision where it made it clear that its obligation was and is to set rates that are fair and reasonable, and to allow a utility the opportunity to earn a fair rate of return.

The Commission Panel has considered the premium paid by Fortis Inc. to acquire the equity capital of TI in 2007. As was the case with respect to the premium paid by KMI for the shares of TI discussed in the 2006 ROE Decision there is no evidence before the Commission that any of the premium paid by Fortis Inc. will be included in any of the Companies' rate bases and recovered from their customers. Further, as was the case with the KMI acquisition, the Commission imposed "ring-fencing" conditions upon Fortis Inc. The Commission Panel considers that the Commission's role is to determine an appropriate capital structure and return on equity for Terasen and that the acquisition of TI by Fortis Inc. is not relevant to the Commission Panel's determination in this regard.

As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so.

Case Name:

Enbridge Gas Distribution Inc. v. Ontario (Energy Board)

Between
Enbridge Gas Distribution Inc., appellant (respondent in appeal), and
Ontario Energy Board, respondent (appellant in appeal)

[2006] O.J. No. 1355

210 O.A.C. 4

41 Admin. L.R. (4th) 69

147 A.C.W.S. (3d) 131

2006 CarswellOnt 2106

Docket: C44102

Ontario Court of Appeal
Toronto, Ontario

D.H. Doherty, M.J. Moldaver and E.E. Gillese JJ.A.

Heard: March 23, 2006.
Judgment: April 7, 2006.

(29 paras.)

Administrative law -- Judicial review and statutory appeal -- Standard of review -- Correctness -- Appeal by the Ontario Energy Board from an order of the Divisional Court setting aside the Board's order made on an application by Enbridge Gas Distribution for a rate increase and directing a new hearing before a different panel of the Board -- Appeal allowed -- Court erred in determining that Board improperly used hindsight when deciding whether added transportation costs incurred by Enbridge justified rate increase -- When impugned passage was read in context of entire judgment, it was to be read in manner consistent with the rest of the Board's reasons.

Administrative law -- Boards and tribunals -- Reasons -- Appeal by the Ontario Energy Board from an order of the Divisional Court setting aside the Board's order made on an application by En-

bridge Gas Distribution for a rate increase and directing a new hearing before a different panel of the Board -- Appeal allowed -- Court erred in determining that Board improperly used hindsight when deciding whether added transportation costs incurred by Enbridge justified rate increase -- When impugned passage was read in context of entire judgment, it was to be read in manner consistent with the rest of the Board's reasons.

Appeal by the Ontario Energy Board from an order of the Divisional Court setting aside the Board's order made on an application by Enbridge Gas Distribution for a rate increase and directing a new hearing before a different panel of the Board. The Board was charged with the responsibility of fixing the rate that Enbridge, a gas distributor and seller to consumers in Ontario, could charge customers for its gas. The Board refused in part Enbridge's application for a rate increase. On appeal to the Divisional Court, the Court held unanimously that the Board erred in law in its application of the legal test to be applied when deciding whether Enbridge was entitled to a rate increase to reflect higher transportation costs incurred by Enbridge as a result of certain agreements it had entered into. In reaching its conclusion, the Divisional court read a passage from the reasons of the Board as demonstrating, contrary to statements made earlier in the reasons of the Board, that the Board had improperly used hindsight when deciding whether the added transportation costs incurred by Enbridge justified a rate increase. On Enbridge's application for a rate increase, the Board was obliged to decide whether the rate increase sought was "just and reasonable". In making that decision, the Board was required to balance the competing interests of Enbridge and its consumers. The balancing process was achieved by the application of what was known as the "prudence" test. Enbridge was entitled to recover its costs by way of a rate increase only if those costs were "prudently" incurred. Knowledge of facts relevant to the prudence of the business decision gained after the decision was made could not be used at the second stage of the "prudence" inquiry to determine the ultimate question of whether the decision was prudent. Those facts could, however, be taken into account at the first stage in determining whether the presumption of prudence had been rebutted. As a result, the Board could use the fact that increased transportation costs had been incurred by Enbridge to decide whether the presumption of prudence was rebutted, but could not use that fact in making the ultimate determination of whether Enbridge's decision to enter into the contracts was prudent. The Divisional court held that reference to a notional deferral account as a "key element of the prudence review" indicated a misuse of hindsight in respect of all contracts under review.

HELD: Appeal allowed. The Board's order was restored. It was an error to read the words "prudence review" as referable only to the second part of the "prudence" inquiry. When the impugned passage was read in the context of the entire judgment, it could and should be read in a manner consistent with the rest of the reasons of the Board. In sum, the phrase "prudence review" was to be read as referring to the entire inquiry, which avoided creating a flat out contradiction between the impugned passage and the rest of the judgment insofar as it described the "prudence" inquiry.

Statutes, Regulations and Rules Cited:

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, s. 36

Ontario Energy Act, 1998

Appeal From:

On appeal from the order of the Divisional Court (Lane, Molloy and Power JJ.) dated March 2, 2005.

Counsel:

David M. Brown and Manizeh Fancy for the appellant in appeal

J.L. McDougall, Q.C., Jerry H. Farrell and Michael D. Schafler for the respondent in appeal

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The judgment of the Court was delivered by

D.H. DOHERTY J.A.:--

I

OVERVIEW

1 This is an appeal with leave by the Ontario Energy Board ("OEB") from the order of the Divisional Court that set aside the order of the OEB made on an application by Enbridge Gas Distribution Inc. ("Enbridge") for a rate increase and directing a new hearing before a different panel of the OEB.

2 Enbridge is a gas distributor and seller of gas to consumers in Ontario. The OEB is charged with the responsibility of fixing the rate that Enbridge can charge consumers for its gas. Enbridge applied for a rate increase. The OEB refused that request in part and Enbridge appealed to the Divisional Court. The Divisional Court unanimously held that the OEB erred in law in its application of the legal test to be used when deciding whether Enbridge was entitled to a rate increase to reflect higher transportation costs incurred by Enbridge as a result of certain agreements it had entered into. In reaching its conclusion, the Divisional Court read a passage from the reasons of the OEB as demonstrating, contrary to statements made earlier in the reasons of the OEB, that the OEB had improperly used hindsight when deciding whether the added transportation costs incurred by Enbridge justified a rate increase.

3 I would allow the appeal and restore the order of the OEB. When the impugned passage is read in the context of the entire judgment, it can and should be read in a manner that is consistent with the rest of the reasons of the OEB. When read in that way, the passage demonstrates no error in law.

II

FACTUAL BACKGROUND

4 Prior to 1996, Enbridge shipped gas from western Canada along the TransCanada pipeline system to Ontario. Beginning in 1996, Enbridge entered into four agreements to acquire transportation services on other pipelines. The first two agreements, Alliance 1 and Alliance 2, provided for transportation along the Alliance pipeline running from Alberta to Chicago. The third agreement, Vector 1, related to transportation along the Vector pipeline running from to Chicago to southwestern Ontario. The fourth agreement, Vector 2, also related to a pipeline running from Chicago to southwestern Ontario but contemplated the transportation of gas sourced in Chicago.

5 The new routes became operational in 2000. They proved more costly than the TransCanada pipeline route. In 2000, Enbridge applied to the OEB for an increase in its rates effective in 2001. That increase was said to reflect, in part, the added costs attributable to the Alliance and Vector contracts.

6 Enbridge's application for a rate increase did not proceed to a hearing in 2000. Enbridge entered into a provisional settlement, conditional upon various contentious issues being deferred to a hearing at a later date. As a term of the 2000 settlement, Enbridge agreed to set up what was described as a "notional deferral account." This account was to record the difference between Enbridge's actual transportation costs using the Alliance/Vector pipelines and its notional costs had it used the TransCanada pipeline system.

7 Enbridge's rate increase application proceeded to hearing in June 2002. It was common ground that Enbridge had added costs as a result of the Alliance/Vector contracts. The issue was whether Enbridge was entitled to recover these costs by increasing its rates.

III

THE DECISION OF THE OEB

8 On Enbridge's application for a rate increase, the OEB was obliged by s. 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, to decide whether the rate increase sought was "just and reasonable." In making that decision, the OEB was required to balance the competing interests of Enbridge and its consumers. That balancing process is achieved by the application of what is known in the utility rate regulation field as the "prudence" test. Enbridge was entitled to recover its costs by way of a rate increase only if those costs were "prudently" incurred.

9 The OEB concluded that the added costs associated with the Alliance 1 and Alliance 2 contracts were not prudently incurred and therefore could not be recovered by way of a rate increase. The OEB did, however, hold that the added costs associated with Vector 1 were prudently incurred and therefore could be recovered. Finally, the OEB held that it had insufficient information to decide whether any added costs associated with the Vector 2 contract were prudently incurred by Enbridge. On its appeal to the Divisional Court, Enbridge challenged the OEB's findings with respect to the Alliance 1 and Alliance 2 contracts.

10 The approach of the OEB to the "prudence" inquiry is captured in the following extract from its reasons:

> While the parties described it in somewhat varying terms, in the Board's view they were in substantial agreement on the general approach the Board should take to reviewing the prudence of a utility's decision.
>
> The Board agrees that a review of prudence involves the following:
>
> * Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
> * To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

* Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
* Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

11 Neither the Divisional Court nor either party to this appeal takes issue with the correctness of the above quoted passage from the OEB's reasons. The "prudence" inquiry described by the Board has two stages. At the first stage, the decision of Enbridge is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision. At the second stage of the inquiry, reached only if the presumption of prudence is overcome, Enbridge must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, Enbridge at the time it made the decision.

12 In the above quoted extract from its reasons, the OEB expressly alluded to the limited role played by hindsight. Hindsight, that is knowledge of facts relevant to the prudence of the business decision gained after the decision was made, could not be used at the second stage of the "prudence" inquiry to determine the ultimate question of whether the decision was prudent. Those facts could, however, be taken into consideration at the first stage in determining whether the presumption of prudence had been rebutted.

13 The records from the notional deferral account kept by Enbridge demonstrated that, during the ten-month period for which the account operated, Enbridge's transportation costs were significantly higher under the Alliance contracts than those costs would have been had Enbridge used the TransCanada pipeline system. The amount of the added transportation costs could not have been known to Enbridge when it entered into the relevant contracts, but became known to Enbridge only after the ten-month period with the benefit of hindsight. Consequently, the OEB could use the fact of the increased transportation costs incurred by Enbridge to decide whether the presumption of prudence was rebutted, but could not use that fact in making the ultimate determination of whether Enbridge's decision to enter into the contracts was prudent.

14 After the OEB accurately described the "prudence" inquiry, it proceeded to apply that inquiry individually to the Alliance 1, Alliance 2, and Vector 1 contracts. The OEB then turned to the Vector 2 contract. That contract was somewhat different than the other three in that it provided for the transportation of gas sourced in Chicago and not Alberta. Accordingly, it was not part of the alternative transportation path created by the other three contracts.

15 In considering the Vector 2 contract, the OEB said:

> The Board notes that the Vector 2 decision was independent from its previous decisions to enter into the Alliance 1 and 2 and Vector 1 contracts and was not required in order to complete the single continuous transportation path from the western Canada supply basin to southern Ontario. <u>In addition, the Board notes that the cost consequences of the Vector 2 contract were not included in the calculation of the Notional Deferral Account, which is a key element of the Board's prudence review of the Alliance and Vector arrangements</u> [emphasis added].

IV

THE REASONS OF THE DIVISIONAL COURT

16 The Divisional Court fastened upon reference by the OEB to the notional deferral account as "a key element of the Board's prudence review" in concluding that, despite the earlier proper description of the "prudence" inquiry by the OEB, it had improperly used hindsight gained by reference to the notional deferral account in deciding that the Alliance 1 and Alliance 2 contracts were not prudent.[1]

17 The Divisional Court applied a correctness standard of review in determining whether the OEB conducted a proper "prudence" inquiry. In this court, counsel for the OEB advanced a forceful argument that the standard of review should, at the highest, be one of reasonableness. It is unnecessary to decide the correct standard of review. Assuming without deciding that correctness is the proper standard of review, the reasons of the OEB clear that standard.

18 The Divisional Court acknowledged that the OEB's reasons must be read as a whole. The court also accepted that the OEB had correctly described the "prudence" inquiry and that the Board was well aware of a distinction which had to be drawn between the use of hindsight in the first and second stage of the inquiry. Despite the OEB's clear statement of the proper test, the Divisional Court ultimately held that the reference to the notional deferral account as a "key element of the prudence review" indicated a misuse of hindsight in respect of all of the contracts, including the Alliance contracts. This single sentence demonstrated to the Divisional Court that, despite the earlier passages from the reasons, the OEB had "slipped in its application of the test and did allow hindsight to creep into its consideration of prudence."

19 In reaching this conclusion, the Divisional Court must have read the words "prudence review" in the impugned passage as referring only to the second stage of the "prudence" inquiry. On that reading, the OEB had improperly used information provided in the notional deferral account to determine the ultimate question of the prudence of the contracts.

20 The Divisional Court erred in reading the words "prudence review" as referable only to the second part of the "prudence" inquiry. Taken as a whole, the reasons indicate that the phrase "prudence review" and similar phrases (*e.g.* "review of prudence") were used throughout the reasons, not as terms of art with a fixed single meaning but in different ways in different parts of the reasons. Sometimes the phrase "prudence review" or an equivalent phrase was used to refer to the entire "prudence" inquiry. Sometimes the OEB used the phrase "prudence review" to refer only to the second stage of that inquiry at which the ultimate question of the prudence of the contracts had to be decided. For example, when describing the submissions of Enbridge at para. 3.1.1, the OEB used the phrase "prudence review" to describe the entire process, including the first stage at which the presumption of prudence operated and during which the information provided in the notional deferral account was clearly relevant. Similarly, under the heading "Board Comments and Findings" (para. 3.12) the OEB used the subheading "Review of Prudence" to describe the entire "prudence" inquiry, including the first stage. Other references to the same phrase in the reasons (*e.g.* para. 3.12.5) used the phrase in the narrower sense to refer only to the second stage of the "prudence" inquiry.

21 Considered in isolation, the phrase "prudence review" in the impugned passage from the reasons of the OEB may be open to the interpretation provided by the Divisional Court. However, the words viewed in isolation can also be taken as referring to the entire "prudence" inquiry. This latter reading is consistent with earlier usage of similar terminology in the reasons and, more significantly, is consistent with earlier statements describing the "prudence" inquiry and the limited role played by hindsight in that inquiry. I read the phrase "prudence review" as referring to the entire inquiry, which avoids creating a flat out contradiction between that passage and the rest of the judgment insofar as it described the "prudence" inquiry.

22 Reasons are sometimes internally inconsistent and that inconsistency can demonstrate an error in law. However, the requirement that the reviewing court read reasons as a whole dictates that, where different parts of the same reasons can reasonably be read so as to maintain consistency within the reasons, that reading must be preferred over one which sends the reasons careening off in different directions and creates an error in law.

23 The reasons of the OEB, read as a whole, do not reveal any legal error in the "prudence" inquiry conducted by the OEB in respect of the Alliance 1 and Alliance 2 contracts.

V

THE OEB'S STANDING TO APPEAL

24 I will make brief reference to one additional argument made by Enbridge. It submitted that the OEB had no standing to appeal the decision of the Divisional Court to this court. Enbridge contends that the *Ontario Energy Act, 1998* gives the OEB authority to participate in an appeal taken to the Divisional Court under the right of appeal provided in that statute. Enbridge argues however, that the *Ontario Energy Act, 1998* does not give the OEB any authority to seek leave to appeal a decision of the Divisional Court in this court.

25 I agree with counsel for the OEB that, as a party to Enbridge's appeal in the Divisional Court, the OEB had standing to seek leave to appeal to this court. That standing flows not from the *Ontario Energy Act, 1998* but from s. 6(1)(a) of the *Courts of Justice Act*, R.S.O. 1990, c. C.43.

26 Enbridge blended its argument that the OEB did not have standing to appeal the order of the Divisional Court with submissions that the OEB should not be allowed to advance arguments on appeal in support of the correctness of its own decision. In *Children's Lawyer for Ontario v. Goodis* (2005), 75 O.R. (3d) 309 (C.A.), this court held that the extent to which a tribunal will be allowed to make submissions in a proceeding involving a decision of that tribunal is a matter for the discretion of the court in which the proceedings are being conducted. The court also considered the factors relevant to the exercise of that discretion in the context of a judicial review application. As this is an appeal and not a judicial review application, it may be that the *Goodis* analysis is not applicable. However, assuming in Enbridge's favour that the analysis does apply, I am satisfied that the factors identified in that analysis do not support Enbridge's contention that the OEB should not have been allowed to participate in this appeal.

27 The OEB advanced essentially two arguments on this appeal. It submitted that the Divisional Court should have used a reasonableness standard of review, and it argued that the reasons of the Board, read as a whole, did not reveal the legal error found by the Divisional Court. The OEB was the only appellant in this court. Its submissions were essential to a proper hearing of both issues.

28 I do not share Enbridge's concern that the participation of the OEB in this appeal could harm the appearance of the OEB's impartiality in any future proceedings involving Enbridge. This appeal came down to a very narrow point. Everyone agreed that the OEB had outlined the proper approach to be taken on Enbridge's application for a rate increase. The narrow question was whether the OEB had "slipped" in one part of its analysis. There is no reason to think that the Board arguing that the reasons reveal no such "slip" should cause any legitimate concern about the impartiality, real or apprehended, of the OEB in its future dealings with Enbridge. Enbridge is after all a sophisticated entity that has a long standing relationship with the OEB. Like all regulated bodies, I am sure Enbridge wins some and loses some before the OEB. I am confident that Enbridge fully understands the role of the regulator and appreciates that each application is decided on its own merits by the OEB.

VI

29 I would allow the appeal and restore the order of the OEB. The OEB has not asked for costs and I would make no order as to costs.

D.H. DOHERTY J.A.
M.J. MOLDAVER J.A. -- I agree.
E.E. GILLESE J.A. -- I agree.

cp/e/qw/qlmxf

e/drs/qlCG/qljal

1 The Divisional Court referred to another passage from the OEB's reasons (para. 3.12.20) and suggested that the OEB had also misused hindsight in that passage. I do not propose to refer to it in detail, as the Divisional Court ultimately determined that this reference alone did not raise "serious concerns" that the OEB had misapplied the "prudence" test. It is sufficient to say that I think it raises no concerns about the misuse of hindsight. The passage indicates that subsequent events validated the risk of higher costs associated with potential in service delays. Enbridge was advised of that risk before it entered into the contracts. The nature and extent of the risk flowing from potential delays was, therefore, properly factored into the second stage of the "prudence" inquiry. The fact that the risk came to pass is some indication of the validity of the risk.

In the Court of Appeal of Alberta

Citation: ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board), 2005 ABCA 122

Date: 20050329
Docket: 0201-0015-AC
Registry: Calgary

Between:

ATCO Gas and Pipelines Ltd.

Appellant (Applicant)

- and -

Alberta Energy and Utilities Board

Respondent (Respondent)

The Court:

The Honourable Mr. Justice Willis O'Leary
The Honourable Madam Justice Anne Russell
The Honourable Mr. Justice Neil Wittmann

Reasons for Judgment Reserved of The Honourable Madam Justice Russell
Concurred in by The Honourable Mr. Justice O'Leary
Concurred in by The Honourable Mr. Justice Wittmann

Appeal from the Decision of the
Alberta Energy and Utilities Board
Dated the 13th day of December, 2001

Reasons for Judgment of
The Honourable Madam Justice Russell

[1] On December 13, 2001, following a Deferred Gas Account Reconciliation Hearing, the Alberta Energy and Utilities Board (the "Board"), in its Decision 2001-110, found the appellant ATCO Gas and Pipelines Ltd. ("ATCO") acted imprudently in managing its gas supplies for the winter of 2000/2001. As a result the Board ordered ATCO to pay $4 million to its customers to compensate them for missed cost savings. In ***Atco Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)***, 2003 ABCA 188, ATCO was granted leave to appeal that decision pursuant to s. 26 of the ***Alberta Energy and Utilities Board Act***, R.S.A. 2000, c. A-17 and section 70 of the ***Public Utilities Board Act***, R.S.A. 2000, c. P-45, on the following issue:

> Did the Board err in law in determining the appropriate standard to be applied with respect to the prudence and reasonableness of the decision of the Applicant utility in the context of this case?

[2] The chambers judge expressly denied leave on the calculation of the $4 million refund.

[3] The City of Calgary ("Calgary") opposed ATCO's application at the Reconciliation Hearing before the Board and was permitted to make submissions on this appeal.

INTRODUCTION

[4] ATCO is a gas distribution utility. It is governed by legislation which authorizes the Board to regulate public utilities and to "ensure that the public pays a fair and reasonable rate for the gas and the owner of the gas obtains a fair and reasonable return on its investment": ***Atco Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*** (2004), 339 A.R. 250, 2004 ABCA 3 at para. 36 ("***Atco Gas***"). Customers of ATCO are charged the actual cost ATCO incurs for the gas it supplies.

[5] The Board has statutory authority to set just and reasonable rates: ***Gas Utilities Act***, R.S.A. 1980, c. G-4, s. 28; ***Public Utilities Board Act***, R.S.A. 1980, c. P-37, s. 81. Gas utility rates, or Gas Cost Recovery Rates (GCRRs) are meant to reflect the market price a utility pays to purchase natural gas. Gas utilities generally apply semi-annually to have GCRRs set by the Board. At the end of a rate period, the Board sets the upcoming rate period's GCRR through a process of reconciling the forecast costs with the actual costs incurred. To account for the risks of fluctuating costs, utilities are allowed to accumulate variances between forecast costs and actual costs: ***ATCO Electric Limited v. Alberta (Energy and Utilities Board)***, 2004 ABCA 215 at para. 26 ("***ATCO Electric***"). That variance is accumulated in a Deferred Gas Account (DGA).

[6] GCRRs are based on forecasts of future prices and costs, as well as any revenue surplus or deficiency incurred from the previous season as a result of the variance between actual costs and

forecast costs. GCRRs are intended to ensure any surplus will be distributed to customers, or to allow the utility to recover any deficiency, depending on the DGA balance. GCRRs are also intended to minimize future variance between actual costs and forecast costs.

[7] Where there is a significant change in gas supply costs between regular applications, a utility is encouraged to apply to the Board for approval of an adjustment to the GCRR in order to minimize the DGA balance: AEUB Order U2000 308. ATCO made such an application in January 2001.

[8] This appeal relates to the reconciliation of ATCO's DGA for the 2000/2001 winter season, and the test applied by the Board in assessing the prudence demonstrated by ATCO in managing its gas supplies during that period.

BACKGROUND

[9] ATCO owns a natural gas storage facility near Carbon, Alberta (the "Carbon facility") which is capable of storing enormous quantities of gas. A certain amount of the gas in storage is needed to provide the minimum pressure required to meet minimum design deliverability. That gas is called 'base gas', or 'cushion gas', and is a rate base asset.

[10] ATCO's practice was to purchase gas and inject it into storage at the Carbon facility during the summer months when demand was low, and to withdraw the stored gas during the winter when demand was high. The gas injected and withdrawn on a cyclical basis is called 'working gas', and is essentially gas inventory.

[11] Because the demand for gas corresponds with price, the practice of injecting and withdrawing working gas can have a favourable effect on prices, referred to as a "physical hedge."

[12] Although ATCO acknowledges the potential cost benefit to customers, it denies engaging in the practice of injecting and withdrawing gas from storage for the purpose of managing gas prices. Rather, ATCO argues its use of storage from the Carbon facility was to meet the operational requirements of the pipeline system, withdrawing gas at variable rates in order to manage fluctuations in demand.

[13] Commencing in the winter of 2000/2001, ATCO decided the Carbon facility was no longer needed for operational purposes. ATCO says its decision was based in part on previous decisions of the Board, which ATCO interpreted as not permitting it to engage in financial hedging because it would be costly over time and adversely affect retail gas market development. Other factors which led ATCO to discontinue use of the Carbon facility for operational purposes were deregulation in the gas utility industry and an abundance of gas supply in the open market in this province. ATCO claims it had no assurance of a market for its gas supply as a result of those factors. However, the Board found that the proposed deregulation of Carbon was not relevant to ATCO's use of gas storage during the 2000/2001 winter season, when the Carbon facility was still in use.

[14] Prior to the 2000/2001 winter season, ATCO had used a flexible withdrawal strategy, dependent on seasonal fluctuations in demand. During the winter of 2000/2001, ATCO changed to a flat withdrawal strategy, meaning that ATCO withdrew gas from the Carbon facility at set monthly flat rates. ATCO claims that as a result of its withdrawal strategy during that season of unprecedented high gas prices, it generated savings to its customers of about $60 million. However, Calgary contends that savings realized from the sale of gas purchased during the summer months when gas prices were low, does not exonerate ATCO from abandoning a flexible withdrawal strategy during the winter, which would have achieved additional savings. Calgary also notes that ATCO's own expert admitted that flexibility has value in a competitive market.

[15] ATCO says its flat withdrawal strategy was designed to avoid speculation as to future prices in the day-to-day management of gas in storage, in keeping with the Board's cautions against engaging in trading.

[16] In Order U2000-161, the Board determined that the use of financial hedging had not previously been used as a method of gas portfolio management (AB VIII, E7). It rejected arguments that ATCO had acted inappropriately by failing to engage in the purchase of gas for storage and simultaneous sale of it on the forward market for later withdrawal. The Board did so on the basis that such activity would be tantamount to trading, for which it had not given any approval (AB VIII, E-8). However, in that Order, the Board recommended that:

> [ATCO] revisit the issue of using financial hedging to help manage its gas portfolio and provide... a comprehensive cost/benefit analysis for its use prior to applying for a winter period Gas Cost Recovery Rate (GCRR) effective November 1, 2000, in order to determine if there is a general consensus among its sales customers for implementation of this form of risk management. (AB VIII, E8-E9)

[17] In a subsequent Order, U2000-183, the Board approved a storage strategy for the April 1, 2000 - March 31, 2001 storage season. That strategy allowed ATCO to buy blocks of fixed price physical gas in the summer and sell blocks of fixed price physical gas for the winter. Order U2000-183 states:

> In . . . Order [U2000-161] the EUB agreed that ATCO GS acted appropriately in the circumstances at that particular time by following the DGA procedures in place, which did not include the use of forward markets or other forms of financial hedging as a method of gas portfolio management. The EUB recommended however that ATCO GS revisit the issue of using financial hedging to help manage its gas portfolio.

[18] Orders U2000-161 and 183 do not support ATCO's position that it was prohibited by the

Board from engaging in financial hedging.

[19] ATCO claims its decision to switch withdrawal strategies reflected the fact that the historical need to vary withdrawals in response to operational requirements for the pipeline system no longer existed. ATCO relies in part on expert reports recommending the best solutions for fluctuations in gas prices. Two of those reports are dated March 16 and April 2, 2001. But since ATCO's decision was made prior to the winter of 2000/2001, those reports could not possibly have influenced it. A third report, dated January 14, 2000 may be applicable, but does not expressly support ATCO's decision to cease using flexible withdrawal; it merely outlines the value and risks inherent in using various strategies.

[20] At ATCO's DGA Reconciliation Hearing in 2001, Calgary introduced a report, prepared by its expert VanderSchee, which concluded that had ATCO withdrawn gas at flexible rates in response to price fluctuations during the winter of 2000/2001 rather than withdrawing at a flat rate, it could have saved customers an additional $8.9 million. According to VanderSchee, such a strategy avoids the need to purchase gas at elevated prices by providing a utility with some flexibility to withdraw variable amounts of gas from storage in response to fluctuations in market prices.

[21] ATCO counters that VanderSchee's report was based on hindsight, and that the recommended strategy would have required ATCO to engage in trading.

Board Decision

[22] The Board ruled that ATCO's decision to implement flat withdrawal in the context of the winter period for 2000/2001 was imprudent. In its decision, the Board applied the following test of prudence:

> . . . [T]he utility would be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information that the owner of the utility knew or ought to have known at the time the decision was made. In making a decision, a utility must take into account the best interests of its customers, while still being entitled to a fair return.

[23] The Board noted that both before and during the winter period 2000/2001, gas forecasts predicted higher gas prices. While the Board recognized that ATCO did not have the benefit of the computer program used by VanderSchee, and could not have predicted the actual price fluctuations so as to realize the optimal savings calculated with the benefit of hindsight, in the Board's view, ATCO ought to have employed a strategy similar to that described by VanderSchee. The Board accepted that VanderSchee's method was not a trading strategy.

[24] The Board held that ATCO ought to have done something to mitigate the high gas prices over the 2000/2001 winter season. The Board found that some of the options available to ATCO at the

time included: continued withdrawal of gas on a flexible basis depending on market conditions, as had been done in the past; use of the excess deliverability on days when gas prices spiked; sale of that portion it did not intend to use; or development of other strategies to deal with the forecast high gas prices.

[25] The Board estimated the total savings not realized by ATCO to be $4 million, and ordered ATCO to refund that amount to its customers through reduced rates in the future.

RELEVANT LEGISLATION

[26] Both the appellant's and respondents' facta make reference to the ***Gas Utilities Act,*** R.S.A. 2000 c. G-5, the ***Alberta Energy and Utilities Board Act***, R.S.A. 2000, c. A-17 and the ***Public Utilities Board Act***, R.S.A. 2000, c. P-45. The gas sales in question and the decision under appeal took place prior to the coming into force of the 2000 Revised Statutes of Alberta on January 1, 2002 by proclamation O.C. 424/2001. Accordingly, although the R.S.A. 2000 statutes apply with respect to ATCO's application for leave to appeal, which occurred after the proclamation date, the matters before the Board, now under appeal, are governed by the ***Gas Utilities Act***, R.S.A. 1980, c. G-4, as amended ("***GUA***"), the ***Alberta Energy and Utilities Board Act***, S.A. 1994, c. A-19.5 ("***AEUBA***"), and the ***Public Utilities Board Act***, **R.S.A.** 1980, c. P-37, as amended ("***PUBA***"). Therefore, all references in this decision are to those Acts as amended on the relevant dates.

[27] All relevant legislation is listed in Appendix A, attached hereto.

BRIEF CONCLUSIONS

[28] The only question before this Court is one of law relating to the test for prudence set by the Board. The application of the four factors of the pragmatic and functional analysis to that question results in a standard of review of reasonableness *simpliciter*.

[29] Applying that standard, we find the Board's test for prudence reasonable and dismiss ATCO's appeal.

STANDARD OF REVIEW

[30] This is an appeal from the decision of an administrative tribunal. Therefore, this Court must determine, in light of the governing legislation, the appropriate level of scrutiny to be applied on review of that decision: ***Pushpanathan v. Canada (Minister of Citizenship and Immigration)***, [1998] 1 S.C.R. 982 ("***Pushpanathan***") at para. 26; ***Dr. Q v. College of Physicians and Surgeons of British Columbia***, [2003] 1 S.C.R. 226, 2003 SCC 19 ("***Dr. Q***") at paras. 21-22; ***Voice Construction Ltd. v. Construction & General Workers' Union, Local 92***, 2004 SCC 23 ("***Voice***") at para. 15.

[31] The standard of review must be determined by applying the pragmatic and functional analysis developed in ***U.E.S., Local 298 v. Bibeault***, [1988] 2 S.C.R. 1048, which entails consideration of four contextual factors: (1) the presence or absence of a privative clause or statutory right of appeal; (2) the expertise of the tribunal relative to that of the reviewing court on the issue in question; (3) the purposes of the legislation and the provision in particular; and (4) the nature of the question – law, fact or mixed law and fact: ***Pushpanathan,*** *supra* at paras. 29-38; ***Canada (Deputy Minister of National Revenue) v. Mattel Canada Inc.***, [2001] 2 S.C.R. 100, 2001 SCC 36 ("***Mattel***") at para. 24; ***Dr. Q***, *supra* at para. 26; ***Law Society of New Brunswick v. Ryan***, [2003] 1 S.C.R. 247, 2003 SCC 20 ("***Ryan***") at para. 27; ***Voice,*** *supra* at para. 16; ***A.U.P.E. v. Lethbridge Community College***, 2004 SCC 28 ("***Lethbridge***") at para. 14. None of those four factors are determinative: ***Pushpanathan,*** *supra* at para. 27; ***Mattel,*** *supra* at para. 24, but evaluated collectively, they will indicate the appropriate degree of deference to afford the administrative decision-maker.

[32] There are three standards of review, from least to most deferential: correctness, reasonableness, and patent unreasonableness: ***Canada (Director of Investigation and Research) v. Southam Inc.***, [1997] 1 S.C.R. 748 at para. 30; ***Baker v. Canada (Minister of Citizenship and Immigration)***, [1999] 2 S.C.R. 817 at para. 55; ***Ryan,*** *supra* at paras. 20 & 24.

[33] Legislative intent underlies each factor in the pragmatic and functional analysis: ***Dr. Q***, *supra*; ***Voice,*** *supra* at para. 18. In this case, the governing legislation is the ***GUA***, the ***AEUBA***, and the ***PUBA***. (See Appendix A)

Privative Clause/Right of Appeal

[34] Section 10 of the ***AEUBA*** gives the Board the same jurisdiction and powers granted to the Public Utilities Board ("PUB"). Thus, the Board has jurisdiction to "hear and determine all questions of law or of fact" pursuant to s. 30 of the ***PUBA***.

[35] Section 26 of the ***Alberta Energy and Utilities Board Act***, R.S.A. 2000, c. A-17 and s. 70 of the ***Public Utilities Board Act***, R.S.A. 2000, c. P-45 allow for appeals from decisions of the Board on questions of law or jurisdiction where leave has been granted. Such a statutory right of appeal implies legislative intent to afford the Board less deference on questions of law or jurisdiction: ***Barrie Public Utilities et al. v. Canadian Cable Television Association et al.*** (2003), 304 N.R. 1, 225 D.L.R. (4^{th}) 206 at 217 (S.C.C.) ("***Barrie***"). However, granting leave on a matter of law or jurisdiction will not necessarily attract a correctness standard: ***Barrie,*** *ibid*; ***Alberta Energy v. Goodwell Petroleum*** (2003), 339 A.R. 201, 2003 ABCA 277 at para. 23. Matters falling within the Board's expertise will warrant deference even where there is a statutory right of appeal: ***Pezim v. British Columbia (Superintendent of Brokers)***, [1994] 2 S.C.R. 557 at 591 ("***Pezim***"); ***Atco Gas***, *supra* at para. 35.

[36] This factor suggests that the Board's decision be afforded limited deference.

Relative Expertise

[37] The Board is a specialized tribunal with expertise in the area of gas utility regulation, which includes protecting the public interest by balancing the competing interests of customers and utilities: ***Coalition of Citizens v. Alberta (Energy and Utilities Board)*** (1996), 187 A.R. 205 at para. 14 (C.A.); ***ATCO Ltd. v. Calgary Power*** **Ltd.**, [1982] 2 S.C.R. 557 at 576; ***Atco Gas,*** *supra* at para. 34; ***ATCO Electric*** at para. 53. However, the expertise of the Board relative to that of this Court will depend on the issue in question: ***Pushpanathan,*** *supra* at para. 33; ***Barrie,*** *supra* at 219.

[38] In this case, the issue for which ATCO was granted leave is the following:

> Did the Board err in law in determining the appropriate standard to be applied with respect to the prudence and reasonableness of the decision of the Applicant utility in the context of this case?

[39] This question could be understood in two ways. Did the Board have jurisdiction to set and apply a standard of prudence in reviewing ATCO's decisions? Alternatively, assuming the Board did have jurisdiction, did the Board employ the proper standard of prudence in respect of ATCO's management decisions? If it is the former, the issue involves legislative interpretation, for which the Board's expertise does not necessarily exceed that of this Court. However, if it is the latter, the issue straddles the line between statutory interpretation and industry-specific practice, in which case, the Board's expertise may very well exceed that of this Court. For the reasons that follow, I conclude the question is one of law and not of jurisdiction.

[40] In support of its position that the proper standard of review is correctness, ATCO argues that any authority the Board has in terms of denying recovery of costs or imposing obligations on ATCO to refund are matters of statutory interpretation, which go to the Board's jurisdiction. However, ATCO was not granted leave on the jurisdictional argument.

[41] ATCO argues the broad applicability of the issue respecting prudence suggests minimal deference, citing ***Chieu v. Canada (Minister of Citizenship and Immigration)*** (2002), 208 D.L.R. (4^{th}) 107 at 120. While conceding the Board has expertise, ATCO says in the absence of a statutory framework, the Board has no expertise with respect to the test for prudence.

[42] ATCO's submissions on the leave question focus predominantly on what ought to be the proper test for prudence, as do submissions by the Board and by Calgary. None of the parties make submissions regarding the Board's jurisdiction to set such a test. Moreover, the issue on which leave was granted was framed as one of law and not as one of jurisdiction. Therefore, focus will be

confined to the issue of law as to whether the Board adopted the proper test of prudence.

[43] The Board enunciated its test of prudence in the context of rate-setting. Fixing just and reasonable rates is a matter squarely within the Board's expertise: ***TransAlta Utilities Corp. v. Alberta Public Utilities Board*** (1986), 68 A.R. 171 at para. 22 (C.A.) ("***TransAlta***"); ***Industrial Power Consumers Assn. of Alberta v. TransAlta Utilities Corp.*** (2000), 255 A.R. 194 at para. 4 (C.A.). The issue is polycentric and requires expertise.

[44] Given the nature of the legal issue and the context surrounding it, the expertise of this Court does not exceed that of the Board which suggests the Board must be afforded curial deference.

Legislative Purpose

[45] The purpose of the governing statutory scheme as a whole, and the specific applicable provisions in particular, must also be considered in determining the appropriate standard of review: ***Dr. Q***, *supra* at para. 30; ***Lethbridge***, *supra* at para. 18.

[46] The Supreme Court of Canada spoke generally to the mandate conferred on the Board by the ***GUA*** and the ***PUBA*** in ***ATCO v. Calgary Power***, [1982] 2 S.C.R. 557 at 576:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities.

[47] The general legislative mandate on the Board is to protect the public interest by way of regulating public utilities. A reviewing court should grant deference where the statutory scheme governing an expert tribunal allows the tribunal to balance competing interests and address broad policy concerns: ***Pezim***, *supra* at 591-92; ***ATCO Electric***, *supra* at para. 56.

[48] In reconciling the DGA and setting a 'just and reasonable' prospective GCRR, the Board conducted a prudence review of the Board's management decisions respecting withdrawal from storage. The question is whether the Board applied the correct test for prudence.

[49] Specific provisions of the governing legislation that confer authority on the administrative tribunal can also be indicators of limited review.[1] Although there is no particular provision in any

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[1] In ***TransAlta***, *supra* at para. 22, Kerans J.A. stated:

. . . Sometimes a legislature invites limited review not by purporting to limit the power of the reviewing court but rather by conferring delegated legislative powers on the tribunal. When the delegation is manifest, as when the tribunal is empowered to "make regulations", the matter is beyond dispute. In other cases, the delegation is not so obvious but is found in the description of the powers of a tribunal in terms which are at once imprecise and evocative. The use of elastic adjectives is usually considered by a court as an implicit granting of a power of the governing Acts which refers to a prudence review, the applicable legislative provisions do give the Board authority to fix 'just and reasonable' rates, a specific mandate connected to the general legislative purpose: ***Re City of Dartmouth*** (1976), 17 N.S.R. (2d) 425 at 432 (S.C.A.D.). The words 'just and reasonable' suggest that the criteria with which the Board exercises its power is flexible and discretionary, and subject to limited review.

[50] The Board has authority to fix just and reasonable rates, taking into account retrospective considerations respecting revenues and costs: ***GUA***, ss. 28(a) and 32(a); ***PUBA***, ss. 81(a) and 83(a). The Board also has authority to fix just and reasonable standards to be observed by utilities: ***GUA***, s. 28(c); ***PUBA***, s. 81(c).

[51] The discretion to determine what is just and reasonable includes the discretion to define justness and reasonableness: see ***Memorial Gardens Association (Can.) Ltd. v. Colwood Cemetery Co.*** [1958] S.C.R. 353 at 357; and ***TransAlta***, *supra* at para. 24, citing ***Edmonton, Jasper Place et al v. Northwestern Utilities Ltd.*** (1960) 34 W.W.R. 241 (Alta. S.C.A.D.). Such discretion suggests a legislative intent to give deference to the Board's methodology in fixing rates and standards. Support for that premise is found in ***Newfoundland Light & Power Co. v. P.U.C. (Bd.)*** (1987), 25 Admin. L.R. 180 (NFCA). There the Court rejected the argument that the Board had exceeded its jurisdiction in determining a just and reasonable rate of return by failing to adopt a particular methodology. That decision was cited with approval in ***Newfoundland (Board of Commissioners of Public Utilities) (Re)*** (1998), 164 Nfld. & P.E.I.R. 60 at para. 29 (NFCA) by Green J.A., who stated:

> . . . The Board therefore has a broad discretion to adopt appropriate methodologies for the calculation of allowable rates of return. So long as the methodologies chosen are not inconsistent with generally accepted sound public utility practice and the purposes and policies of the Act, and can be supported by the available opinion evidence, the determination of what constitutes a just and reasonable return in a given case will generally be within the province of the Board and will not normally be interfered with.

[52] ATCO's customers are charged with the actual cost of gas supplied by ATCO. Actual costs incurred by a utility are reflected in the DGA balance. Those costs depend in part on that utility's management strategy, including the execution and management of a hedging plan. Assessing management decisions may necessarily factor into a reconciliation hearing and the Board's determination and implementation of just and reasonable rates: see Costello, K., "Should Commissions Pre-Approve a Gas Utility's Hedging Activities?" (***NRRI***, 34^{th} Annual Regulatory

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to the tribunal to form its own "opinion" or make "policy" or to exercise a "discretion" - in fine, to make law. The key power of this Board is to fix "fair and reasonable" rates. This is a good example of a grant of a wide discretion.

Conference: Tampa, Florida, December 10, 2002).

[53] The Board's determination of the test governing its review of ATCO's management decisions accords with the general legislative mandate to serve the public interest by balancing the consumer's interest in just and reasonable rates with the utility's interest in earning a reasonable rate of return. In light of the discretionary nature of the specific rate-setting provisions, this factor suggests that deference be given by this Court.

Nature of the Question

[54] Leave to appeal is granted only on questions of law or jurisdiction, which would generally favour less deference. However, as the question relates to the management of a utility and marketing strategies, it is one for which the Board has greater expertise than does this Court. Where the question of law is at the core of the administrative decision-maker's expertise, some deference is owed to that decision-maker: ***Voice***, *supra* at para. 29.

[55] ATCO argues the Board erred in its articulation and application of the prudence test, in finding ATCO imprudent. The application of the test is an issue of mixed fact and law. Because the governing legislation grants a right of appeal with leave only on questions of law or jurisdiction, questions of mixed fact and law can only come before this Court where there is an extricable legal question: see ***Housen v. Nikolaisen***, [2002] 2 S.C.R. 235 at para. 36. The Board's application of its prudence test is an issue inextricably bound to the facts and is therefore not properly before us. The question of whether the prudence test set by the Board was correct, is extricable and is a question of law. Because it is a question which falls within the discretion granted to the Board by its governing legislation, some deference must be afforded.

Conclusion on Standard of Review

[56] In the context of this case, only one of the four ***Pushpanathan*** factors, the statutory right of appeal, indicates a less deferential standard. Otherwise, the Board's expertise and the governing legislation suggest the Board be given a high degree of deference, given the nature of the issue.

[57] In a decision released after oral argument concluded in this case, this Court found that because the legal question engaged was of general import, the appropriate standard to be applied to the Board's decision concerning entitlement to carrying costs is in the mid-range of judicial review spectrum, that is reasonableness. But the Court also found that "the Board enjoys expertise superior to this Court in determining the appropriate methodology for calculating prudent costs of financing a particular segment of a utility's operations": ***ATCO Electric***, *supra* at para. 62. Thus, Fraser C.J.A. concluded the appropriate standard to apply to that decision is patent unreasonableness. However, here, the Court is not being asked to review a methodology of calculation of rates, but rather whether the Board erred in determining the appropriate standard in reviewing the reasonableness of managerial decisions.

[58] Considering the four contextual factors in this case, and the import of the prudence test to the utilities industry, I conclude the appropriate standard of review is reasonableness *simpliciter*. Applying that standard, the Court must ask "whether there is a rational basis for the decision . . . in light of the statutory framework and the circumstances of the case": ***Cartaway Resources Corp. (Re)*** (2004), 319 N.R. 1, 2004 SCC 26 at para. 49.

ANALYSIS

Did the Board err in law in determining the appropriate test to be applied with respect to the prudence and reasonableness of the decision of the Applicant utility in the context of this case?

[59] The Board concluded ATCO acted imprudently because it "could have, and ought to have, maximized the value of the 'excess' deliverability by using it on days when prices were spiking or by selling the deliverability it did not intend to use . . .", and by failing to do so, ATCO "was not acting in the best interests of customers . . ." In reaching that conclusion the Board adopted the following test of prudence:

> . . . a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take into account the best interests of its customers, while still being entitled to a fair return.

[60] The Board cited its earlier Decision 2000-01, wherein it stated:

> [The concept of prudence]. . . has been recognized as a tool available to regulators, and in most instances involves an evaluation of whether or not a decision reflects good judgment and discretion and is reasonable in the circumstances which were known, or reasonably should have been known when the decision was made.

[61] ATCO maintains that the proper test for prudence requires the presumption of managerial prudence, and that the Board erred by failing to presume management had acted prudently. Although the Board did not expressly presume prudence, it may have done so implicitly by determining to uphold ATCO's decision unless it was satisfied that ATCO acted unreasonably: AB I, p. F21. But ATCO also submits that mere unreasonableness or error in judgment is not sufficient to establish imprudence and that a regulator is not entitled to step into the role of a manager. In ATCO's view, if any error was made at all, it was a mere error of judgment and not outside the realm of what any reasonable business person would do. Any such error would not constitute negligence and could thus not properly constitute imprudence.

[62] In the course of ATCO Pipelines 2003/2004 General Rate Application (Tab 18 ATCO's authorities), Calgary disputed any presumption of prudence in regulatory law that ATCO Pipelines' forecasts are reasonable, which in its view would be a reversal of the onus of proof. Further, Calgary says there is no logical reason to apply a presumption of correctness to a utility budget. Instead, Calgary says the utility has the onus of establishing the reliability of its forecast expenditure. Calgary says there is no major difference between the Board's and ATCO's articulation of the test for prudence, and that ATCO's main complaint is with the application of the test.

[63] Calgary also notes that the test applied by the Board has been applied by the Ontario Energy Board, which addressed the test for prudence in the context of rate regulation in the transportation industry in RP - 2001-0029. That Board acknowledged that a presumption of prudence on the part of a regulated utility is implicit in the framework underlying rate regulation. The Ontario Energy Board said that in considering the prudence of any action, it is engaged in a retrospective review of the reasonableness of the utility's action at a given point, and the forseeability of any changes in circumstances is critical to that review. At para. 2.36 that Board stated:

> A poor outcome does not govern the assessment of prudence. Prudence is however, called into question if the commitment was made casually, that is without a reasonable level and scope of analysis, or recklessly, or primarily for some ulterior non-utility or ulterior corporate purpose. (Calgary authorities Tab 18 p. 21)

[64] The term "prudence" is well known in the utility rate-making industry and has a significant history. Included in Calgary's materials is a 2002 paper from The National Regulatory Research Institute of Ohio State University (the "NRRI") entitled, "State Commission Regulatory Considerations Concerning Security-Related Cost Recovery in Utility Network Industries", which references a 1985 NRRI publication: *The Prudent Investment Test in the 1980's* (the "*Prudent Investment Test*"). *The Prudent Investment Test* describes the history of the concept of prudence and its use in regulated public utilities. The authors describe the concept of prudent investment as: "a regulatory oversight standard that attempts to serve as a legal basis for adjudging the meeting of utilities' public interest obligations, specifically in regard to rate proceedings": ch. 2, p. 20. The 2002 NRRI paper cited by Calgary and *The Prudent Investment Test* at 93, both suggest that before a regulator investigates the prudence of a utility, the presumption of prudence must be rebutted.

[65] As a standard in public utility regulation, prudence is described as a concept borrowed from legal principles, such as negligence. In other words, the public utility will be held to a managerial duty of care:

> What is prudent is deemed to be ascertainable through the reasonable efforts of competent managers with sound and reasonable judgment. That risk is involved in managerial decision making is judicially acknowledged. But, the deliberate exposure to substantial risk in the exercise of managerial discretion is by its very nature imprudent, for risk is to be avoided, if not altogether, at least insofar as possible

under the circumstances: *The Prudent Investment Test*, p. 47.

[66] A presumption of prudence triggers an onus of proof on the party impugning managerial decisions. However, if that presumption is rebutted, a public utility's decision will be reviewed, applying an objective test of reasonableness to the facts and circumstances surrounding the decision, without relying on hindsight: *The Prudent Investment Test*, p. 93

[67] In determining whether a company had exercised proper discretion in matters requiring business judgment, the U.S. Supreme Court in ***State of Missouri ex re, Southwestern Bell Telephone Company v. Public Service Commission of Missouri*** 262 U.S. 276, 289 (1923), stated:

> The Commission is not the financial manager of the corporation and it is not empowered to substitute its judgment for that of the directors of the corporation; nor can it ignore items charged by the utility as operating expenses unless there is an abuse of discretion in that regard by the corporate officers.

[68] In support of its submission that for actions to qualify as imprudent they must be dishonest or obviously wasteful, ATCO cites the dissenting judgment of Justice Brandeis, in footnote 1 at 289 of that case:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.

[69] In ***West Ohio Gas Co. v. Public Utilities Commission of Ohio (No. 1)***, 294 U.S. 63, 68 (1935), at p. 25 the U.S. Supreme Court held that:

> A public utility will not be permitted to include negligent or wasteful losses among its operating charges. The waste or negligence, however, must be established by evidence of one kind or another, either direct or circumstantial.

The Court continued at p. 26:

> Good faith is to be presumed on the part of the manager of a business. . . In the absence of a showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.

[70] There, the Court concluded that imposition of a penalty was wholly arbitrary in the absence

of evidence showing any warning to the company that fault was imputed to it and that it must give evidence of care.

[71] The Board concedes that the standard of prudence is similar to the standard of care required in assessing negligence, but argues that with respect to a regulated public utility, the test is not what a reasonable businessman would have done in the circumstances, but rather what a reasonable public utility would have done. In ***Acker v. United States***, 298 U.S. 426, 431 (1936), cited in *The Prudent Investment Test* at 32, regarding management judgment, the U.S. Supreme Court held that:

> ...[T]he charge is for a public service, and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs...

[72] The Board's broad discretion to set just and reasonable utilities rates must be exercised in the public interest, which requires consideration of both sides of the rate paying equation: ***ATCO Electric***, *supra* at 132. That process implicitly entails scrutiny of management decisions. With respect to negotiated settlements Fraser C.J.A. held in ***ATCO Electric*** at para. 145 that the Board "is entitled to assume that what the utility has negotiated and agreed to is in fact in the utility's best interests." However, in the context of rate setting, the starting point for scrutinizing management decisions is the presumption that it is in the utility's interest to make prudent decisions which also reflect the interests of its customers, by avoiding needless expenditure. That presumption will matter only when the scales are evenly balanced.

[73] In this case, in determining to uphold ATCO's decision unless satisfied ATCO had acted unreasonably, the Board correctly acknowledged the presumption of prudence. The test it articulated to be applied in reviewing the prudence and reasonableness of ATCO's decisions is reasonable.

CONCLUSION

[74] ATCO's complaint with the Board's application of the prudence test involves questions of fact, and is not properly before this Court. The only matters at issue on this appeal are whether the Board properly acknowledged a presumption of prudence, and properly articulated the test of prudence, in assessing ATCO's management decisions. The Board's articulation of the prudence test is consistent with its previous decisions and with the line of authority addressing the concept of prudence in the context of public utilities. Given the governing legislation and the circumstances of this case, there is a rational basis for the test of prudence articulated and relied on by the Board in its decision.

[75] Accordingly, the appeal is dismissed.

Appeal heard on April 21, 2004

Reasons filed at Calgary, Alberta
this 29th day of March, 2005

Russell J.A.

I concur:

O'Leary J.A.

I concur:

Wittmann J.A.

Appearances:

H.M. Kay, Q.C.
L.E. Smith, Q.C.
For the Appellant

J.R. McKee
A.E. Domes
for the Respondent

P.L. Quinton-Campbell
R.B. Brander
for the Third Party

Appendix "A"

Current Legislative Provisions

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

. . . . .

Public Utilities Board Act, R.S.A. 2000, c. P-45

70(1) Subject to subsection (2), on a question of jurisdiction or on a question of law, an appeal lies from the Board to the Court of Appeal.

(2) Leave to appeal shall be obtained from a judge of the Court of Appeal on application made within one month after the making of the order, decision, rule or regulation sought to be appealed from, or within any further time that the judge under special circumstances allows, and on notice to the parties and to the Board, and on hearing those of them that appear and desire to be heard, and the costs of the application are in the discretion of the judge.

. . . . .

Applicable Repealed Legislative Provisions

Alberta Energy and Utilities Board Act, S.A. 1994, c. A-19.5 [repealed] ("***AEUBA***")

10(1) Fort he purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB and the PUB that are granted or provided for by any enactment or by law.

. . . . .

Gas Utilities Act, R.S.A. 1980, c. G-4, as amended. [Repealed] ("***GUA***")

16 When it is made to appear to the board, on the application of any owner of a gas utility or of any municipality or person having an interest, present or contingent, in the matter in respect of which the application is made, that there is reason to believe that the tolls demanded by an owner of a gas utility exceed what is just and reasonable, having regard to the nature and quality of the service rendered or of the gas supplied, the Board

> ***(a)*** may proceed to hold any investigation that it thinks fit into all matters relating to the nature and quality of the service or the gas supplied, or to the performance of the service and the tolls or charges demanded therefor,
>
> . . .
>
> ***(c)*** may disallow or change, as it thinks reasonable, any tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any contract existing between the owner of the gas utility and a municipality at the time the application is made that the Board considers fair and reasonable.
>
> . . .

25(1) No owner of a gas utility shall

> ***(a)*** make, impose or extract any unjust or unreasonable or unjustly discriminatory or unduly preferential individual or joint rate, commutation rate or other special rate, toll, fare, charge or schedule for any gas or service supplied or rendered by it within Alberta,
>
> . . .
>
> ***(c)*** adopt, maintain or enforce any regulation, practice or measurement that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or otherwise in contravention of law, or provide or maintain any service that is unsafe, improper or inadequate, or withhold or refuse any service that can reasonably be demanded and furnished when ordered by the Board,
>
> . . .

28 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which shall be made after giving notice to and hearing the parties interested,

> ***(a)*** fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed thereafter by the owner of the gas utility,
>
> . . .
>
> ***(c)*** fix just and reasonable standards, classifications, regulations, practices, measurements or service which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,
>
> . . .
>
> ***(e)*** require an owner of a gas utility to supply and deliver gas to the persons, for the

purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

. . .

32 In fixing just and reasonable rates, tolls or charges, or schedules thereof, to be imposed, observed and followed thereafter by an owner of a gas utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,
(ii) a subsequent fiscal year of the owner, or
(iii) 2 or more of the fiscal years of the owner referred to in subclauses (I) and (ii) if they are consecutive

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines has been due to undue delay in the hearing and determining of the matter, and

(d) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

. . . . .

Public Utilities Board Act, R.S.A. 1980, c. P-37, as amended. [Repealed] ("***PUBA***")

30 The Board may, as to matters within its jurisdiction, hear and determine all questions of law or of fact.

. . .

81 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which shall be made after giving notice to and hearing the parties interested,

> (a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules thereof, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed thereafter by the owner of the public utility;
>
> . . .
>
> (c) fix just and reasonable standards, classifications, regulations, practices, measurements or service which shall be furnished, imposed, observed and followed thereafter by the owner of the public utility;
>
> . . .

. . .

83(1) Subject to subsection (2), in fixing just and reasonable rates, tolls or charges, or schedules thereof, to be imposed, observed and followed by an owner of a public utility,

> (a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of
>
> > (i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules thereof,
> > (ii) a subsequent fiscal year of the owner, or
> > (iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,
>
> and need not consider the allocation of those revenues and costs to any part of such a period,
>
> . . .
>
> (b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules thereof, as the Board determines is just and reasonable.
>
> (c) the Board may give effect to such part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules thereof, as the Board determines has been due to undue delay in the hearing and determining of the matter, and
>
> (d) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b)

or (c), is to be used or dealt with.

1981, c. E-4.1, s. 17; 1984, c. 60, s. 4; 1988, c. S-13.75, s. 9; 1995, c. 11, s. 14.