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

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

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. - Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

In accordance with the Regulatory Timetable set for this proceeding, we enclose for filing:

1. the electronic version of FortisBC Energy Inc.'s Final Submission regarding Non-PBR Issues; and

2. two legal authorities which have been cited in the Final Submission.

FortisBC Energy Inc. is also contemporaneously filing in this proceeding a joint submission with FortisBC Inc. on PBR Plan Design.

Sixteen hard copies of the enclosed will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher Bystrom

CRB/ccm
Encl.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT,

R.S.B.C. 1996, CHAPTER 473 (THE "ACT")

and

RE: FORTISBC ENERGY INC.

APPLICATION FOR APPROVAL OF A MULTI-YEAR PERFORMANCE

BASED RATEMAKING PLAN FOR 2014 THROUGH 2018

FINAL SUBMISSION OF

FORTISBC ENERGY INC.

REGARDING NON-PBR ISSUES

April 25, 2014

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PART ONE: INTRODUCTION AND OVERVIEW

A. Introduction

1. FortisBC Energy Inc. ("FEI") filed its Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the "Application") on June 10, 2013, with evidentiary updates filed on July 16, 2013, August 23, 2013 and February 21, 2014.[1]

2. As more particularly described in the Application, FEI respectfully requests the following:

(a) Approval of the mechanisms of FEI's proposed multi-year performance based ratemaking ("PBR") plan (the "PBR Plan").

(b) Approval of FEI's Delivery Rates for all non-bypass customers effective January 1, 2014, resulting in a 0.6 percent increase to the delivery charge compared to the 2013 delivery charge.

(c) Approval of the Rate Stabilization Adjustment Mechanism ("RSAM") rider effective January 1, 2014.

(d) Approval of the discontinuance, modification and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts.

(e) Approval of changes to FEI's accounting policies.

(f) Approval of the continuation of the debiting of the Midstream Cost Recovery Mechanism ("MCRA") and crediting of delivery margin revenue in the amount of $3.6 million as described in Section C2.3 of the Application.

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[1] Exhibits B-1, B-1-1, B-1-3, B-1-5 and B-15. Errata and amendments to the Application were filed on December 13, 2013 regarding the total factor productivity report in Appendix D (Exhibit B-1-4) and on March 3, 2014 regarding the cost-effectiveness test for low-income demand side management programs (Exhibit B-43).

(g) Approval of the allocation of costs for corporate services and shared services.

(h) Acceptance of Energy Efficiency and Conservation ("EEC") expenditures schedules for 2014 to 2018, with the continuation of the EEC framework previously approved by the Commission with some changes.

FEI has provided an updated list of its Approvals Sought and Draft Order in its Evidentiary Update dated February 21, 2014 (the "February 2014 Evidentiary Update").[2]

3. In parallel with this Application, FEI's sister company, FortisBC Inc. ("FBC"), has filed its own Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018. As the review of the methodology of the PBR Plan for both FEI and FBC (together, "FortisBC") was combined, FortisBC has addressed the methodology of the proposed PBR Plan in a joint Final Submission (the "PBR Submission").

4. This Final Submission will therefore address the aspects of the Application that fall outside the methodology of the PBR Plan. In the section below, FEI provides an overview of the non-PBR components of the Application and where they are addressed in this Submission.

B. Overview

5. In this proceeding FEI is seeking approval of a PBR Plan for 2014 to 2018 and its delivery rates for 2014, as well as acceptance of EEC expenditures schedules over the term of the PBR from 2014 to 2018 (the "PBR Period"). FEI and FBC have addressed the methodology for the PBR Plan in their PBR Submission. In this Submission, FEI addresses those components of the proposed 2014 delivery rates and other approvals that fall outside the PBR Plan methodology. These components include the 2014 demand and other operating revenue forecasts, the 2013 base year O&M ("2013 Base O&M"), the 2013 base year capital costs ("2013 Base Capital"), financing costs, taxes, accounting policies and deferral accounts. An overview of the topics addressed in this Submission is provided below.

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[2] Exhibit B-1-5.

6. As under cost of service rate setting, a component of setting FEI's delivery rates under the PBR Plan is the demand forecast. FEI has set out its 2014 demand forecast in Section C1 of the Application using the same forecast methodology used in past revenue requirement applications and approved by the Commission for rate setting purposes. The 2014 demand forecast is used to derive a forecast of revenue at existing rates which, when compared against FEI's costs for 2014, determine the extent to which FEI's existing rates should be adjusted to recover those costs. The 2014 demand forecast is addressed in Part 2 of this Submission.

7. A second component in setting the 2014 delivery rates is FEI's forecast of other operating revenue ("Other Revenue"), including, for example, revenue from late payment and connection charges and FortisBC Energy (Vancouver Island) Inc. ("FEVI") wheeling charges. This Other Revenue offsets FEI's costs during the year. FEI has set out its forecast of Other Revenue for 2014 in Section C2 of its Application. As no material issues were raised with respect to this forecast, the Other Revenue forecast is not addressed in this Submission. If issues are raised by interveners in their Final Submissions, FEI will respond in its Reply Submission.

8. Under the PBR Plan, FEI's controllable costs will be derived by a PBR formula rather than being set on a forecast cost of service basis. FEI has described the calculation of controllable O&M and capital costs under the PBR Plan on pages 54 to 67 of the Application as updated by the February 2014 Evidentiary Update. This Submission will be focussed on the starting input to this calculation, which is the 2013 Base O&M and 2013 Base Capital (together referred to as the "2013 Base Year Costs"). FEI's proposed 2013 Base Year Costs rely on the O&M and capital costs that were approved by the Commission for 2013 ("2013 Approved"), pursuant to Commission Order G-44-12 and Reasons for Decision dated April 12, 2012 (the "2012-2013 RRA Decision"), regarding the FEU's 2012-2013 Revenue Requirements and Rates Application (the "2012-2013 RRA"). Adjustments to the 2013 Approved amounts are made for sustainable savings realized by FEI during the 2012-2013 period as well as for deferred O&M charges and accounting policy changes. Consistent with PBR theory, this approach provides the appropriate base costs for the PBR Plan based on FEI's level of required resources at the outset of the PBR Period as determined by the Commission through a full oral public hearing process.

This provides the correct starting costs from which FEI will be expected to find efficiencies to meet the efficiency factors in the PBR formula. FEI's proposed 2013 Base O&M and 2013 Base Year Capital Costs are addressed below in Parts 3 and 4 of this Submission, respectively.

9. While not the focus of this Submission, FEI has included in Section C3 and C4 of its Application a forecast of its O&M and capital expenses over the PBR Period for information and reference purposes. These forecasts are indicative of the future trends, opportunities and challenges that FEI expects during the PBR Period. The O&M and capital forecasts are used in Section B7 of the Application to compare the delivery margin under the PBR Plan with the delivery margin under the cost of service forecasts. This comparison provides a reasonableness check on the PBR Plan as discussed in the PBR Submission. As described in Section B of the Application, the formula-based approach generates costs for the 2014-2018 years that are below the Company's forecast costs. FEI will therefore be required to find productivity improvements during the upcoming PBR Period in order to mitigate the cost increases that it is forecasting.

10. While FEI has undertaken considerable effort to develop its O&M and capital forecasts for the PBR Period, these forecasts are not a detailed cost of service forecast such as were produced for the 2012-2013 RRA on which the 2013 Approved amounts are based. While FEI has responded in detail to information requests regarding its forecasts, FEI is not seeking approval of its forecasts of O&M and capital as the proposed PBR Plan is not based on these forecasts. FEI has therefore not addressed these forecasts further in this Submission. If interveners choose to take issue with aspects of the forecasts in their Final Submissions, FEI will respond in its Reply Submission to the extent necessary.

11. As discussed above, FEI has proposed 2013 Base Year Costs which will be used to determine future costs under the PBR formula. In addition, FEI's delivery rates will be set to recover items that are not tracked under the PBR formula. These include interest expense, return on equity, taxes, pension and OPEB expenses and insurance costs, depreciation and

amortization, CPCN expenditures and other deferred charges.[3] In this Application, FEI is seeking delivery rates that will recover these costs for 2014. To set the delivery rates in subsequent years of the PBR Period, forecasts of these expenses, projected deferral account balances, and other rate base information will be provided during the Annual Review process.[4] The Annual Review process is discussed more fully in FortisBC's PBR Submission.

12. In Section D of the Application, FEI has provided its forecast of its financing costs and tax expenses, as well as a discussion of accounting policies and procedures and deferral accounts. FEI's delivery rates are impacted by various accounting policies and procedures, including cash working capital, depreciation expense, and the allocation of shared and corporate services. FEI is requesting changes to accounting policies related to the allocation of O&M and capital costs to align with US GAAP and the treatment used by FBC. FEI is also requesting changes to the treatment of depreciation expense that are necessary for the proper functioning of the PBR Plan, as well as a new allocation method for executive cross charges between FEI and FBC that reflects the level of integration of the executives at this time. Lastly, FEI is seeking approval of the creation of two new deferral accounts, modification to the amortization periods or other features of a number of existing accounts and the discontinuation of 18 deferral accounts that are no longer required. FEI also has a number of deferral accounts for which no changes are sought and which will continue as previously approved.[5] Financing, taxes, accounting policies and deferrals are addressed in Part 5 of this Submission.

13. Part 6 of this Submission addresses Directive 63 from the 2012-2013 RRA Decision regarding FEI's use of the BCUC Uniform System of Accounts ("BCUC USoA"). As discussed in Part 6, FEI submits that its new revised code of accounts provides more meaningful and comparable information than the BCUC USoA which has not been substantially updated since 1961.

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[3] Application, Section 6.3.2, pp. 68 to 70.

[4] Application, Section 6.8, pp. 78-79.

[5] Application, p. 290, Footnote 60.

14. Part 7 of this Submission addresses the allocations to thermal energy services ("TES"), which are now provided solely by FortisBC Alternative Energy Services Inc. ("FAES"). As described in Part 7, all employees who are dedicated solely to FAES have been transferred out of FEI, while FEI's time tracking process ensures that all costs attributable to FAES operations have been, and will continue to be, appropriately charged. Costs for corporate and administrative services provided to FAES are recovered by FEI through an annual overhead allocation to the thermal energy services deferral account ("TESDA") as determined by the Commission. FEI has proposed the TESDA Overhead Allocation Variance Account to capture any variance in the overhead allocation.

15. This Application also includes a request for acceptance of EEC expenditure schedules for 2014 to 2018 for FEI, FEVI and FortisBC Energy (Whistler) Inc. ("FEW", and together with FEI and FEVI, the "FEU").[6] These EEC expenditures are not subject to the PBR formula, but are captured in deferral accounts and amortized as approved by the Commission. The FEU have provided substantial evidence in this proceeding demonstrating that its proposed EEC expenditures over the PBR Period are in the public interest. This evidence includes the FEU's 2014-2018 EEC Plan, which provides details on each program including cost-effectiveness test results and estimated program participation. In the FEU's submission, the evidence demonstrates the FEU's commitment to rigorous program planning and cost effectiveness testing. The FEU's EEC expenditures are addressed in Part 8 of this submission.

16. FEI submits that the totality of the evidence provided in this proceeding demonstrates that the approvals sought are just and reasonable and in the public interest. FEI respectfully requests that the Commission approve the Application.

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[6] FEI notes that amalgamation of the FEU was approved by the Commission in Order G-21-14 on February 26, 2014. Assuming amalgamation as of January 1, 2015, the FEU will be simply FEI from that date forward.

PART TWO: 2014 DEMAND FORECAST

A. 2014 Demand Forecast

17. Section C1 of the Application provides FEI's 2014 demand forecast for natural gas and resulting revenues and margins at existing rates. This section of the Application includes yearly forecasts beyond 2014 for informational purposes only. The demand forecast for 2015 and subsequent years of the PBR Period will be updated through the Annual Review process.[7] Please see FortisBC's PBR Submission for a discussion of the Annual Review process.

18. As described in Section C1.3 of the Application, FEI's 2014 demand forecast is based on the same methodology used in previous years and accepted by the Commission for the purpose of setting rates. The three key inputs into the demand forecast are: the forecast number of customers for each residential and commercial customer class; the forecast average use per customer ("UPC") for each residential and commercial customer class; and the demand from Industrial customer classes as determined by the annual Industrial Survey. The 2014 demand forecast results are presented in Section C1.4 of the Application.

19. As explained in Section C1.4.2 of the Application, FEI has used a Revenue Stabilization Adjustment Mechanism ("RSAM") since 1994. The purpose of the RSAM is to stabilize delivery margin received from residential and commercial customer classes on a UPC basis. The RSAM captures variances from forecast to actual UPC for factors such as weather that cannot be forecast with any degree of accuracy. If UPC rates vary from the forecast levels used to set the delivery rates, FEI records the delivery revenue differences in the RSAM deferral account for refunding or recovering through a rate rider to the RSAM rate classes. The RSAM does not capture variances from the industrial demand forecast or variances from the customer additions forecast.

20. FEI has filed an analysis in Appendix E5 of the Application to comply with Commission Directive #1 in the 2012-2013 RRA Decision to file a financial analysis of the impact

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[7] Application, p. 78; Exhibit B-11, BCUC IR 1.56.

of variances in the forecast of customer additions. FEI's analysis shows that there is a small positive impact on the earned return when adding a customer that was not forecast and conversely a small negative impact to earned return when not adding a customer that was forecast. Any increase or decrease in earned return is temporary until the next time delivery rates are reset. There has been no consistent historical trend of over or under forecasting customer additions. Moreover, the historical 10 year average would suggest it is more likely for FEI to experience a slight decrease in earned return (approximately $227 thousand) compared to the forecast due to actual customer additions being, in general, less than forecast.[8] In summary, this analysis demonstrates that FEI's customer additions forecast methodology of relying on third-party residential housing forecasts and historical trends for commercial additions[9] is reasonable and that there is no evidence of bias in these forecasts.

21. FEI's demand forecast for natural gas for transportation ("NGT") customers has been presented separately in Section C1.4.6 and Appendix H of the Application.[10] The demand forecasts were substantially revised in FEI's evidentiary updates.[11] FEI delivers NGT, which includes Compressed Natural Gas ("CNG") and Liquefied Natural Gas ("LNG") service, under Rate Schedules 6P, 16, 46 and 25. While revenue under Rate Schedules 6P and 25 are minor (at approximately $0 and $100 thousand, respectively), FEI is forecasting $1.9 million in revenue under Rate Schedule 16 and the new Rate Schedule 46 in 2014.[12] This revenue serves to offset the overall delivery cost of service.

B. Issues Raised

22. The issues raised in the IR process related to the demand forecast are considered in the subsections below.

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8 Application, pp. 115-116 and Appendix E5.

9 Application, pp. 94 to 96

10 Exhibit B-1-5, Updated Version of Appendix H, Section 5.2.

11 Exhibit B-1-3 and B-1-5. See Exhibit B-11, BCUC IR 1.69.1 and Exhibit B-24, BCUC IR 2.244.1 for a discussion of the evidentiary update in Exhibit B-1-3. In the February 2014 Evidentiary Update (Exhibit B-1-5) a clean, revised version of Appendix H of the Application has been included.

12 Exhibit B-1-5, p. 6 and the Updated Version of Appendix H, Section 5.2.

(a) The Scope of the RSAM

23. The potential for the RSAM to be expanded in scope to include customer additions was considered in IRs.[13] As explained in response to those IRs, the justification for the RSAM has been to mitigate the impact of weather and other uncontrollable factors on UPC, not the impact of variances in customer additions. It is important to mitigate the impact of weather on UPC because the impact of weather on UPC is in the same direction for all residential and commercial rate classes and the variances can be material. In contrast, the impact of variances in customer additions on demand is immaterial because the number of customer additions is very small compared to the total number of customers contributing to the overall demand. Further, the direction of variances (above or below forecast) in the customer additions forecast will be different among the rate classes, which mitigates the impact of overall variances in any given year. There has also been no consistent historical trend of over or under forecasting customer additions. For these reasons, FEI has not proposed expanding the RSAM to include customer additions.[14]

24. The potential for the RSAM to be expanded to include industrial customers was considered in IRs, and FEI was asked whether the lack of an RSAM mechanism could reduce the incentive for FEI to pursue EEC measures for these customers.[15] An RSAM mechanism for industrial customers is both unnecessary and problematic. It is unnecessary because, unlike residential and commercial classes, the vast majority of the revenues from industrial customers are fixed and therefore do not vary with the actual volume of gas delivered.[16] Expanding the RSAM to industrial customers would also be problematic for interruptible industrial customers under Rate Schedules 7, 27, and 22, who receive non-firm service and only pay for the volumes

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[13] Exhibit B-11, BCUC IRs 1.61.2, 1.61.3 and 1.61.3.1.

[14] Application, p. 115; Exhibit B-11, BCUC IRs 1.61.2, 1.61.3 and 1.61.3.1.

[15] Exhibit B-11, BCUC IRs 1.67.2, 1.212.1 and 1.212.1.1, and 1.212.2.

[16] Exhibit B-11, BCUC IRs 1.57.2 and 1.212.1.

delivered. An RSAM would effectively impose a fixed revenue stream on these customers, which would be inconsistent with the interruptible service that they receive.[17]

25. FEI also has a suitable incentive to pursue EEC programs for customers, whether or not they are covered by the RSAM. This is demonstrated by the fact that FEI already has EEC programs for such customers. For customers involved in industrial manufacturing, FEI devises customer tailored energy efficiency applications and, for those customers that are larger commercial-type customers (included in Rate Schedules 4, 5, 7 & 27), FEI has EEC programs related to HVAC and efficient boilers.[18] FEI's commercial and industrial EEC programs are discussed further in Part 8 of this Submission.

26. Any adverse impact to FEI from an industrial customer adopting an EEC measure would be small and unlikely. This is because there is significant time required for industrial customers to establish a capital plan for an energy efficiency upgrade, to apply for and receive approval for an EEC incentive, and then to implement the energy efficiency upgrade. Industrial customers will therefore be able to forecast the reduced volumes as part of the Industrial Survey for that year, so that the lower volumes would be incorporated into the future year forecast.[19] Any adverse impact would therefore be limited to at most a one year period until the revenue and cost impact would be included in the next revenue requirement application or annual review.

27. In summary, expanding the RSAM to industrial customers would be inconsistent with the rate design for those customers and is not necessary to provide an incentive to pursue EEC programs. FEI therefore submits that there is no reason at this time to expand the RSAM.

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[17] Exhibit B-11, BCUC IR 1.67.2.

[18] Exhibit B-11, BCUC IR 1.212.1.2.

[19] Exhibit B-11, BCUC IR 1.212.3.

(b) Industrial Customer Forecast

28. Information requests raised a potential concern with the industrial demand forecast for Rate Schedule 22 customers and asked whether any improvements could be made to the industrial forecast methodology.[20] The concern with respect to the Rate Schedule 22 customers appears to be driven by the variances from forecast since 2008. As FEI explained with respect to the industrial demand forecast generally, FEI understands from customers that the variance has increased recently due in part to industrials customers' response to falling gas prices as compared to other sources of energy. In this situation it is not unreasonable for customers to consume more than forecast.[21]

29. FEI has explained its industrial survey methodology in detail in the Application and in response to IRs.[22] FEI does not make any adjustments to forecasts that are submitted to it by its industrial customers. The industrial survey used to develop the forecasts in this Application used the latest version of FEI's industrial survey tool. This tool is web based and allows each customer to easily review both their historical consumption levels as well as the survey data they sent FEI the previous year. FEI describes the tool as follows:[23]

> "In 2012 FEI used an enhanced forecasting tool in the form of a modern and secure web site. The web site provided each industrial customer with 10 years of historical consumption data (if available). The web site also displayed a graph of their most recent survey (if completed) compared to the actuals for 2012. The forecast to actuals graph was a new feature and designed to help each customer develop a more accurate forecast".

The materials from FEI's workshop on the demand forecast further explain the working of the survey with the aid of screen shots of the web site tool.[24] FEI has improved the survey as much as it can at this time to allow Rate Schedule 22 customers to provide a better forecast.[25]

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[20] Exhibit B-11, BCUC IR 1.67.2; Exhibit B-24, BCUC IR 2.243.

[21] Exhibit B-11, BCUC IR 1.67.2.

[22] Application, pp. 96-97; Exhibit B-11, BCUC IRs 1.67.1 and 1.67.4; Exhibit B-24, BCUC IRs 2.243.1 and 2.243.1.2.3.

[23] Exhibit B-11, BCUC IR 1.67.4.

[24] Exhibit B-2, EEC and Forecast Workshop Materials, PDF pp. 71 to 77.

30. FEI forecast methodology for industrial customers has been used for many years and approved by the Commission as reasonable most recently in the 2012-2013 RRA Decision. While there may be recent variances above forecast due to industrial customers' response to falling gas prices as compared to other sources of energy, this is not a reason to change methodology. FEI submits that its proven approach is sound and produces reasonably reliable forecasts for the purpose of rate setting.

31. While FEI's methodology is reasonable, variances from any forecast are to be expected. Variances from the industrial forecast have a small impact on rates.[26] For example, if Rate Schedule 22 customers were to decrease their forecast demand by 5%, this would increase the average rate for all non-bypass customers by $0.005 / GJ, all else equal.[27] To the extent that there are variances over the PBR Period, under the proposed PBR treatment, variances between actual and forecast industrial revenues each year will be subject to the 50/50 earnings sharing mechanism.

(c) Core Market Administration Expense ("CMAE")

32. CMAE costs are a component of FEI's cost of gas as they are required to manage FEI's natural gas and propane supply functions.[28] FEI has not requested approval of CMAE costs in this proceeding, but has instead sought approval of the CMAE costs as part of the cost of gas approval process as was done under FEI's previous PBR plans.[29] As the Commission has set a separate process for review of the CMAE costs, which is currently under consideration, FEI will not address CMAE costs further in this Submission.[30]

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[25] Exhibit B-24, BCUC IR 2.243.1.2.3.

[26] Exhibit B-24, BCUC IR 2.243.1.

[27] Exhibit B-24, BCUC IR 2.243.1.1.

[28] Application, p. 113.

[29] Exhibit B-24, BCUC IRs 2.293 and 2.294.

[30] Order G-255-13 dated December 19, 2013 established the regulatory process for review of CMAE costs. The proceeding record is on the Commission website at the following URL: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=427.

PART THREE: 2013 BASE O&M

A. Overview of the 2013 Base O&M

33. The 2013 Base O&M is the starting controllable O&M costs to which the PBR formula will be applied to derive the formulaic controllable O&M costs over the PBR Period. The 2013 Base O&M is the starting point from which future productivity is measured and should reflect the level of required resources at the outset of the PBR Plan. FEI will be managing the achievement of any savings or incremental costs on a company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. The integrity of the PBR Plan and FEI's right to a reasonable opportunity to earn a fair return therefore depends on the 2013 Base O&M being set to reflect the level of required resources at the outset of the PBR Plan. Otherwise, if the 2013 Base O&M is set below this level, the targets under the PBR Plan will be unfairly and systematically increased, potentially denying FEI its right to a reasonable opportunity to recover its prudently incurred expenses and earn a fair return over the term of the PBR Period.

34. FEI has described how it has derived its 2013 Base O&M in Section B6.2.4.1 of the Application, with details on a department-by-department basis in Section C3.[31] Table C3-2 of the Application shows a breakdown of how the 2013 Base O&M was determined.[32]

35. FEI's 2013 Base O&M begins with the 2013 O&M approved by the Commission in the 2012-2013 RRA Decision (the "2013 Approved O&M"). The 2012-2013 RRA Decision was the outcome of a full oral public hearing in which the Commission fully reviewed and determined the cost of service rates for FEI for 2012 and 2013. The 2013 Approved O&M is therefore an appropriate starting point for the 2013 Base O&M.

36. As outlined in Section B6.2.4.1 of the Application, FEI makes three adjustments to the 2013 Approved O&M to arrive at the 2013 Base O&M, as follows:

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[31] Application, as updated by Exhibit B-1-5.

[32] Table C3-2 was also updated in Exhibit B-1-5 for 2013 Actual expenditures.

(a) *Sustainable Savings*. An adjustment to recognize the sustainable savings that were realized in 2012 and 2013 that should be carried forward to future years.

(b) *2013 Deferrals*. Adjustments to include actual incurred 2013 non-controllable O&M that is held in deferral accounts in 2013.

(c) *Accounting Changes.* Adjustments are made that reclassify items from O&M to capital to reflect the accounting changes sought over the PBR Period.

37. Each of the adjustments is discussed in the subsections below.

(a) Adjustment for Sustainable Savings

38. FEI has identified $16.17 million[33] in sustainable savings compared to the 2013 Approved O&M that are appropriately embedded in the 2013 Base O&M. FEI has classified these amounts as savings because they result in a reduction in the 2013 Base O&M which is then carried forward to future years of the PBR Period.[34]

39. FEI describes the source of the sustainable savings as follows:[35]

> "The labour savings arise primarily in the Operations, Information Technology, Engineering Services & Project Management, Operations Support, Human Resources and Finance/Regulatory departments. … The labour savings are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels. Savings in non-labour resulted from the savings in meter reading and billing operations captured in the Customer Service Variance deferral account, offset by increases to support customer and code driven requirements, and the increased use of contractors."

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[33] This is the updated number based on 2013 Actuals as discussed in the February 2014 Evidentiary Update, Exhibit B-1-5. See updated Table C3-2.

[34] Exhibit B-24, BCUC IR 2.275.2.

[35] Application, p. 123.

40. The sustainable savings over the 2012-2013 period were identified by comparing FEI projected O&M costs for 2013 (the "2013 O&M Projection") to 2013 Approved O&M.[36] As stated by FEI regarding the development of the 2013 O&M Projection:

> "FEI's department managers have developed a 2013 O&M Projection by department, that can be relied upon to establish a 2013 Base O&M as a meaningful starting point for the PBR. The 2013 Projection was compiled by adjusting the 2013 Budget a) to incorporate FTE levels and an extrapolation of annualized savings, based on those that were achieved in the first 4 months of 2013, and b) to recognize pressures and opportunities of a permanent nature identified for 2013. Comparing the 2013 O&M Projection to the 2013 Allowed O&M results in the assessment of sustainable savings."

Projected savings as between 2012 and 2013 were detailed in Exhibit B-1, BCUC IRs 1.83.1 and 1.84.1.

41. FEI updated the projected sustainable savings taking into account actual spending in 2013 ("2013 Actual") as described in the February 2014 Evidentiary Update in Exhibit B-1-5. As discussed there, FEI has identified a total of $16.17 million[37] in sustainable savings compared to 2013 Approved O&M and has reduced its 2013 Base O&M accordingly. Examples of particular sustainable savings described in the Application and IR responses are briefly reviewed below:

(a) *Customer Service*. The vast majority of the sustainable savings - $12.5 million - was achieved in the Customer Service department and captured by the Customer Service Variance Deferral Account.[38] FEI anticipated the potential for these savings and applied for and received deferral treatment for these types of costs over the 2012-2013 test period. The scope of the Customer Service Deferral Account has been discussed in detail in BCUC IR 2.278.1. The savings realized include the signing of a new meter contract, resulting in $8.6 million in

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36 Exhibit B-24, BCUC IR 2.275.2.

37 This is the updated number based on 2013 Actual results as discussed in the February 2014 Evidentiary Update, Exhibit B-1-5. See updated Table C3-2.

38 Application, p. 151; Exhibit B-11, BCUC IR 1.92.1 and Exhibit B-24, BCUC IR 2.278.1.

reduced costs.[39] FEI has also described in detail the productivity improvements in Customer Service and the regulatory history related to the in-sourcing of the customer service function in the Application and in IRs. In short, FEI's Customer Care Enhancement Project has continued to generate cost savings for the benefit of customers. Other sources of savings in Customer Service were from lower billing operation costs, the transfer of the Knowledge and Learning department to existing resources in Human Resources, research studies and bad debt expense.[40]

Operations Department. Partially offsetting the cost pressures in this department, particularly in 2012, Distribution realized savings in IBEW training costs of $750 thousand which are expected to be sustainable through the PBR Period. The training efficiencies were gained through the adoption of a peer training and competency assessment training model as well as fewer new hires in 2012 and greater use of e-learning tools.[41]

(b) *Engineering Services & Project Management*. In this department, FEI realized $1.5 million in sustainable savings.[42] This includes $600 thousand reduction in processing BC One Call tickets,[43] as well as savings due to integration through the appointment of a common Director of Engineering Services and Manager, Project Management Office for the electric and gas utilities.[44]

(c) *Operations Support*. Operations Support realized $1.123 million in sustainable savings.[45] These savings are due in part to the implementation of a variety of

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39 Application, p. 144 and pp. 150-151; Exhibit B-11, BCUC IR 1.90.2.

40, Application, page 151 and see Exhibit B-11, BCUC IR 1.90.2 for further description of these savings.

41 Application, p. 139.

42 Application, Table C3-2, as updated by Exhibit B-1-5.

43 Application, p. 175; Exhibit B-24, BCUC IR 2. 264.1.

44 Application, p. 174; Exhibit B-24, BCUC IR 2.265.1.

45 Application, Table C3-2, as updated by Exhibit B-1-5.

internal productivity enhancements throughout the department, as listed in the Application.[46]

(d) *Environment Health & Safety*. EH&S realized $319 thousand in sustainable savings[47] as a result of the alignment of processes, programs and operating standards and roles between the FEI and FBC.[48]

(e) *Finance and Regulatory Services*. The 2013 O&M Projection for Finance and Regulatory Services was approximately $900 thousand lower than the 2013 Approved, reflecting efficiencies realized in the department.[49] Updating for 2013 Actual resulted in a further $180 thousand in sustainable savings.[50]

42. In the 2012-2013 RRA Decision, the Commission was critical of FEI's productivity focus. The Commission, amongst other items, directed FEI to reduce its O&M by $4 million as a productivity challenge and directed FEI to come back with a PBR or productivity plan. As demonstrated by the above, FEI has responded to this direction with renewed focus on productivity[51] and has reduced the 2013 Approved O&M by approximately $16.17 million, in addition to meeting the Commission's productivity challenge.

43. The benefit to ratepayers is that FEI has reduced the 2013 Base O&M by these savings so that they will carry forward throughout the PBR Period.

(b) 2013 O&M Deferral Accounts

44. As stated in the Application, the 2013 deferral adjustments reflect the re-basing of 2013 Approved O&M to 2013 Actual amounts for those items that are considered non-

46 Application, p. 179.
47 Application, Table C3-2, as updated by Exhibit B-1-5.
48 Application p. 187; Exhibit B-24, BCUC IRs 2.270.2 and 2.270.5.
49 Application, p. 192.
50 Exhibit B-1-5, p. 3.
51 FEI's focus on productivity is discussed on pages 11 to 13 of the Application.

controllable, and for which the variance is captured in a deferral account. In 2013, FEI recorded the following amounts in O&M related deferral accounts:

(a) $571 thousand in the Tax Variance deferral account related to PST for 9 months of 2013 (equivalent to the $762 thousand for the full year).

(b) $923 thousand in the BCUC Levies Variance deferral account, representing the difference between the actual amounts paid in 2013 and the amounts approved in rates.

(c) $93 thousand in the Insurance Variance deferral account, representing the difference between the actual insurance paid in 2013 and the amounts approved in rates.

(d) $10.605 million in the Pension and Other Post-Employment Benefits ("OPEB") Variance deferral account related to O&M.

(c) Accounting Changes

45. The 2013 Base O&M includes adjustments for two accounting changes: the allocation of retiree pensions/OPEBs and the capitalization of annual software costs. These changes reallocate costs from O&M to capital. The changes are described in Section D3.1 of the Application and are considered below in Part 5 of this Submission.

(d) Conclusion on 2013 Base O&M

46. FEI's 2013 Base O&M represents the appropriate base level of costs for the PBR period, starting with the 2013 Approved O&M and reducing it for sustainable savings realized over the last test period. Adjustments were also made to incorporate O&M deferrals during 2013 and accounting changes applied for in the Application. FEI's PBR expert Black & Veatch considers this approach to be reasonable given the fact that the current rates were set based

on a full oral hearing that occurred recently.[52] It is common to use approved rates in circumstances where the revenue requirements were recently assessed, and making known and measured adjustments is also appropriate.[53] The 2013 Base O&M is therefore a reasonable and appropriate base on which to begin the PBR Plan.

B. Issues Raised

47. This section will address the issues raised with respect to the 2013 Base O&M. O&M allocations from FEI to FAES are discussed in Part 8 below.

(a) Biomethane O&M

48. FEI's Application proposed to include in O&M the biomethane program costs that were recoverable from all customers as approved by the Commission.[54] As noted in BCUC IR 2.313.1 there were two amounts included in the 2013 Base O&M related to the biomethane program: $410 thousand for Labour and Customer Education and $84 thousand for Interconnect O&M Facilities.[55]

49. FEI stated that it would revise its proposal if necessary following the Commission's Decision on FEI's filed Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis (the "Biomethane Application").[56]

50. In FEI's February 2014 Evidentiary Update, FEI updated its 2013 Base O&M to take into account the Commission's Order G-210-13 and Reasons for Decision on FEI's Biomethane Application.[57] Order G-210-13 revised the cost allocation rules for the biomethane

[52] Application, p. 55.
[53] Application, p. 55; also see AUC Decision 2012-237, at pp. 19-20 (Exhibit B-1-1, Application, Appendix D9-3).
[54] Exhibit B-24, BCUC IR 2.347.1.
[55] Also see Exhibit B-24, Attachment 347.1, provided in response to BCUC IR 2.347.1.
[56] Exhibit B-24, BCUC IR 2.348.2.
[57] Exhibit B-1-5, p. 7.

program, ordering that all costs of the biomethane program must be captured in the Biomethane Variance Account ("BVA") for recovery from those customers who participate in the program. Biomethane O&M costs will therefore no longer be recovered in FEI's delivery rates, but through the Biomethane Energy Recovery Charge ("BERC"). The exception to this is the cost of the seven interconnection projects which were approved prior to Order G-210-13 under the Pilot Program and will continue to be recovered in delivery rates. The Commission clarified this as follows:[58]

> "FEI is correct in its understanding that the intent of the Commission Panel's decision is to apply the modifications to the Biomethane Program on a go forward basis from the date of the Decision. The Commission Panel confirms that, as such, the interconnection facility cost allocation methodology for the Pilot Program as approved in Commission Order G-194-10 applies to the costs associated with the interconnection facilities for the seven projects listed above".

51. Given the change in the cost recovery of biomethane program costs, in its February 2014 Evidentiary Update, FEI has removed the $410 thousand in biomethane program O&M from the 2013 Base Year for purposes of calculating the 2014-2018 O&M under the PBR formula.[59] This amount is now included as a flow-through item outside of the PBR Plan formula, with an offsetting recovery in Other Revenue, since it will not be recovered through delivery rates. However, as the existing approved seven interconnection projects remain recoverable in delivery rates, the $84 thousand of associated O&M remains in the 2013 Base Year O&M and will remain under the PBR Plan.

(b) CNG and LNG O&M

52. As discussed in Section B of the Application, O&M (and capital) associated with FEI's NGT program, which includes both CNG and LNG service, are excluded from the PBR Plan as they are tied to incremental revenue that is not part of the formula approach.[60] The

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[58] BCUC Letter L-10-14, dated February 18, 2014.

[59] Exhibit B-1-5, p. 8.

[60] Application, p. 56, as amended by Exhibit B-1-5.

exception to this approach, as explained further below, is the O&M in the Energy Solutions and External Relations department for NGT services.[61]

53. Attachment H of the Application provides a detailed discussion of FEI's NGT program, including the complex regulatory history that has taken place over the past 4 years. FEI has revised Attachment H twice during this proceeding. The first update was to take into account Commission Decisions, including the Commission's Decision on FEI's Application for Rate Schedule 16.[62] The second update was to take into account new regulations related to CNG and LNG service, including Special Direction No. 5 which has directed the Commission to treat CNG and LNG services as part of the natural gas class of service.[63] As a result of Special Direction No. 5, FEI is no longer seeking approval of separate classes of service to account for its CNG and LNG activities. These changes, however, do not change FEI's approach of generally excluding NGT O&M (and capital) from the PBR Plan.

54. The NGT-related O&M included in the 2013 Base O&M is offset by revenues from the Commission-determined overhead and maintenance ("OH&M") charge of $0.52/GJ, which appears as Other Revenue. Under the proposed PBR methodology, the O&M amounts will be escalated by the O&M formula over the PBR Period. The revenue recovery amounts will be re-forecast each year as part of the Annual Review process.[64]

(c) Trends in Full-Time Equivalents

55. IRs explored the level of Full-Time Equivalents ("FTEs") historically and for the 2013 base year. FEI submits that the Commission should be determining the 2013 Base O&M based on the 2013 Approved levels, and not on a detailed historical or forecast review of FTE

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[61] Exhibit B-24, BCUC IRs 2.313.1, 2.346.1.1, 2.346.2, and 2.346.3.

[62] Exhibit B-1-3.

[63] Exhibit B-1-5.

[64] Exhibit B-24, BCUC IRs 2.313.1, 2.345.1, 2.346.1.1, 2.346.2, and 2.346.3. Exhibit B-1-5, February 2014 Evidentiary Update, p. 6. (Note that the FEI staff O&M for fueling stations is different than the $289 thousand in contracting resources for NGT stations which have been excluded from the 2013 Base O&M.)

levels. A review of FTE levels was conducted in the 2012-2013 RRA proceeding and was part of the evidentiary record upon which the Commission determined the 2013 Approved amounts.

56. Nonetheless, the evidence shows that FEI's FTE levels are reasonable. For instance, the response to BCUC IR 2.253.3 shows that the increase in O&M FTEs over the 2010 to 2013 period is due to Customer Service.[65] This increase in Customer Service FTEs is a result of the in-sourcing of the customer service function which has been reviewed and approved by the Commission.

57. Further, BCUC IR 2.252.1 provides a detailed comparison of the FTE levels in September 2013 to the FTE levels forecast by FEI in the 2012-2013 RRA. As shown in that response, FEI has reduced FTE levels by 156 FTEs (excluding Customer Service) compared to the 2013 forecast in the 2012-2013 RRA. This was accomplished in part in response to the Commission's productivity challenge in the 2012-2013 RRA Decision.

58. Historical FTE counts were also examined on a department or business group basis. The IRs asked, for example, about FTEs in the Energy Solutions and External Relations ("ES&ER") and Energy Supply and Resource Development ("ES&RD") business units.[66] Although the increases in these units have been previously reviewed by the Commission in the 2010-2011 and 2012-2013 revenue requirement proceedings, FEI has summarized the reasons for the increases in BCUC IR 2.254.1 and the IRs referenced in that response. FEI has also provided a comprehensive description of the changes in business drivers to the ES&ER department in BCUC IR 2.284.1. The result of this information is a documentation of the cost pressures and changes experienced in these departments and business units and the past history of Commission approvals. This in turn illustrates why it is appropriate that the 2013 Base O&M be set using the 2013 Approved amounts.

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[65] Exhibit B-24, BCUC IR 2.252.1.

[66] Exhibit B-24, BCUC IR 2.254.1.

59. While FEI has provided the information requested in IRs, FEI submits that it is not necessary to determine an FTE count for 2013 or revisit historical FTEs and the reasons for historical increases in this proceeding. Rather, the Commission should rely on the 2013 Approved O&M which was the outcome of a full cost of service review, including a full oral public hearing process.

(d) Historical Trends in Expenditures and Comparison to Other Factors

60. Some IRs[67] appeared to seek to revisit Commission-approved O&M costs based on comparisons to costs in historical periods as far back as 2006 or based on comparison to other factors. As discussed below, FEI submits that these comparisons are not valid. More fundamentally, however, to the extent that such information is relevant, it was available for the Commission's consideration in the 2012-2013 RRA proceeding. That proceeding was based on FEI's full cost of service forecast which underwent a full oral hearing review. The 2013 Approved O&M costs represent the Commission's determination of the cost of service for 2013 based on a full evidentiary record including historical costs. FEI submits that the outcome of that proceeding is the reasonable starting place for the 2013 Base Year Costs.[68]

61. In response to these types of IRs, FEI has explained historical cost increases in an number of departments, including the following:

(a) FEI has described the drivers of cost increases in the Engineering and Project Management department since 2008, as has been previously reviewed and approved by the Commission. These include changes to the BC Safety Authority Gas Safety Regulations and the CSA Z662 standard.[69]

(b) For Operations Support, FEI reviewed the reasons for cost increases since 2008, stating: "The increases were driven by a number of items that were discussed in

[67] E.g. Exhibit B-11, BCUC IR 1.127.3; Exhibit B-24, BCUC IR 2.258.1.

[68] Exhibit B-11, BCUC 1.127.3.

[69] Exhibit B-11, BCUC IR 1.135.4.

past RRAs, including maintaining the existing radio network repeater sites, additional gas detectors, pipeline emergency response equipment, electronic meters and meter sets. Further costs were incurred for additional AMR network fees, the introduction of Measurement Canada's mandatory sampling plan SS-06 and to support additional capital work to sustain the existing pipeline."[70]

(c) FEI has described the increased costs in the Facilities department, noting that the majority of the cost increases from 2008 to 2013 are due to the two new contact centres approved through CPCN Order G-23-10 and the 2012-2013 RRA Order G-44-12.[71]

(d) FEI has outlined the drivers of cost increases in the ES&ER department since 2010, including Safety Education Messaging, the Renewable Natural Gas ("RNG") program, the Long Term Resource Plan ("LTRP"), the High Carbon Fuel Switching Program, Natural Gas Awareness, growth initiatives and inflation.[72]

62. FEI was also asked why it was appropriate to set its 2013 Base O&M for the Finance and Regulatory department at an amount that is higher than the 5-year historical average.[73] The short answer to this query is that Commission has already determined the just and reasonable O&M costs of the Finance and Regulatory department that ought to be recovered in 2013. The 2012-2013 RRA Decision did not consider it appropriate to use a 5-year average of costs for any departmental O&M expenditure. Further, the use of a 5-year average would not reflect FEI's required level of resources. As FEI stated in BCUC IR 1.117.1:

> "A review of the historical numbers shows that, for each of the past 5 years, with the exception of 2011, FEI's costs have increased. In the context of labour, benefit and non-labour inflation alone, it is not realistic to expect that the 2013 projection would be equal to the average of the previous 5 years. Rather, the expectation would be that the 2013 projection would be higher than the 2012

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70 Exhibit B-24, BCUC IR 2.267.1.

71 Exhibit B-24, BCUC IR 2.268.1.

72 Exhibit B-24, BCUC IR 2.284.1.

73 Exhibit B-11, BCUC IR 1.117.1.

> actual, all else equal. The average annual increase in the departmental O&M over the five year period is approximately 2.6%. At a minimum, the cost increase would be expected to be in line with this. But given the one-time efficiencies that are reflected in the historical numbers (the elimination of executive and support positions and unfilled vacancies), this historical average increase is understated when looking forward".

FEI has also explained the variances from the amounts approved in the 2012-2013 RRA and there is no evidence or suggestion of any imprudent expenditures. Moreover, FEI has proposed to reduce its 2013 Base O&M for this department by $1,080,000 compared to 2013 Approved to take into account sustainable savings it has achieved over the course of the 2012-2013 test period.[74]

63. Comparisons back to years as far back as 2006 may be based on the incorrect assumption that the business has remained static over the intervening years and that the costs should be expected to be similar. In fact, as discussed by FEI in response to various IRs, the business has not remained static. As noted by FEI, earlier years reflect different accounting classifications and a different set of circumstances, including different economic circumstances, regulatory requirements and different physical requirements of the system. For example, with respect to Operations, FEI explained:[75]

> "For example, several accounting and operating code changes have occurred since 2007 which preclude using 2007 as a comparative base. IBEW training costs, prior to 2010 were included in loaded labour charge-out rates effectively allocating half of these types of costs to capital and billable work; since the accounting change, these costs are now 100% O&M. Similarly, a number of code and regulation changes were introduced in 2010/2011 particularly CSA Z662, Annex M&N which increased funding requirements around gas asset security and integrity management programs".

Other reasons why comparing the 2013 Base O&M to 2007 is not valid include various cost pressures, the in-sourcing of Customer Service, and increases in Pension and OPEB.[76] In short,

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[74] Exhibit B-11, BCUC IR 1.117.1 and Exhibit B-1-5, February 2014 Evidentiary Update, p. 3.

[75] Exhibit B-11, BCUC IR 1.127.3.

[76] Exhibit B-24, BCUC IRs 2.258.1, and 2.259.1.

FEI's various explanations of cost increases demonstrate that any comparison of 2013 costs to earlier years, such as 2006, 2007 or 2008, needs to take into account the changes that have incurred in the intervening period and Commission-approved cost increases.

64. IRs also sought to compare certain categories of FEI's costs to factors that were not appropriate.[77] For example, FEI was asked for a comparison of ES&ER cost in relation to customer additions. FEI explained why this is not appropriate as follows:[78]

> "While FEI has provided the calculation requested for the years 2010 through 2014, such a calculation does not provide for a relevant or appropriate measure. This is because the ES&ER department is responsible for a variety of activities which include customer attraction, customer retention, increasing natural gas throughput, the development and implementation of new service offerings, safety education messaging, the preparation of the LTRP, internal and external communications, among others, and not all of these activities are directly related to customer additions. Furthermore, there are other areas of the Company's operations that play a role in customer retention and additions. For these reasons, the calculations provided in the schedule do not provide any meaningful or relevant information from which to base decisions."

65. Similarly, FEI was asked to compare trends in ES&ER O&M and ES&ER FTEs since 2006 to average customers and total natural gas deliveries, apparently based on the assumption that there should be a correlation.[79] As stated in FEI's response, there is no direct relationship between FTEs in this department and average customers or natural gas deliveries. FEI states:[80]

> "It is incorrect, however, to assume that costs incurred in a given year have a direct relationship with total customers and net customers added to the system in that same year. This assumption is flawed for the following reasons:
>
> - The ES&ER group not only engages in activities to retain and attract customers but also on compliance activities including the LTRP and

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[77] E.g. Exhibit B-24, BCUC IRs 2.261.1 and 2.269.1.

[78] Exhibit B-11, BCUC IR 1.111.2.

[79] Exhibit B-24, BCUC IR 2.254.2.

[80] Exhibit B-24, BCUC IR 2.254.2.

System Extension Test Filings. Please refer to BCUC IR 1.100.1 for a list of key activities for this group.

- There is often a time lag for benefits to accrue from an initiative. Activities undertaken in one period and often over a period of time will reap benefits in future periods. For example, the company began its efforts on the GGRR initiative in consultation with the government in a period before the first GGRR customer was added to the natural gas system.

- There are other external influences such as changes to codes, energy policy and regulation and the cost of gas appliances, for which FEI has limited influence, that significantly affect customer retention, additions and growth, and such changes in external factors cannot be "measured" in a such a graph.

Therefore, to base decisions on an evaluation of staffing levels against natural gas deliveries gives an inaccurate and incomplete picture of the business and the factors that affect it."

Notably, the ES&ER department includes the EEC group whose purpose is to encourage reduction in demand, not increase natural gas deliveries.[81]

66. In summary, questions of the nature described above appear to be based on the incorrect premise that trends in FEI's actual costs can be compared against some other trend that is more indicative of what FEI's costs should have been, whether that be inflation, an historical average or one particular year or set of years that appears attractive. In fact, the only determination of what levels of O&M are just and reasonable is by reference to the Commission's own decisions, which reflect the Commission's consideration of, and determinations on, the circumstances of the utility from year to year. Looking back at cost increases in previous years leads back to a Commission approval of that increase, with the exception of variances from approved. Therefore, attempts to revise the 2013 Base Year Costs by reference to some earlier period inevitably lead to a direct contradiction with the

[81] Application, p. 153.

Commission's past decisions. FEI therefore submits that the 2013 Base Year Costs should be set with referenced to the 2013 Approved amounts.

(e) Expenditures above 2013 Approved

67. While overall FEI's 2013 O&M Projection was below the 2013 Approved O&M, some categories of O&M costs were above the 2013 Approved amounts in those categories. Information requests asked whether expenditures above the 2013 Approved O&M should be included in the 2013 Base O&M.[82] FEI's general response to this issue is as follows:[83]

> "The base year is set on cost of service principles. The sustainable savings represent a combination of the factors used to adjust the base period to a cost of service. Similarly, any over expenditure of the approved budget represents the actual cost of service because the budget is just a forecast of what costs are likely to be in the period.
>
> The 2012 and 2013 Approved budgets prepared in 2011 as part of the 2012/2013 RRA were developed with the best information at the time. However, business conditions and requirements change over time affecting the level of funding and resources required. In order to reflect the current level of required resources, FEI's 2013 Base O&M reflects both increases and also decreases from the 2012 and 2013 Approved base. It would be asymmetrical to adjust for under-expenditures, but not to adjust also for the over-expenditures.
>
> FEI's approach is consistent with historical practice where the Commission has accepted that it is FEI's role to manage the prioritization of its O&M funding and that changes amongst departments have traditionally formed the base for O&M going into a new test year.
>
> In addition, not including expenditures above approved would understate the current resource requirements in the Base Year and potentially undermine the achievability of the PBR Plan. In filing a base year using updated cost of service as has been done with the various adjustments, the base year is a starting point from which future productivity is measured and should reflect the current level of required resources for the PBR Plan. FEI will be managing the achievement of any savings or incremental costs on a Company-wide basis as part of the overall

[82] E.g., Exhibit B-24, BCUC IRs 2.276.6, 2.279.3, 2.284.1, 2.287.2 and 2.287.3. Activity level view of variances for 2012 and 2013 were provided in Exhibit B-24, BCUC IRs 2.279.1 and 2.279.2.

[83] Exhibit B-24, BCUC IR 2.276.6.

> challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. This point is particularly important because of the number of years that FEI has operated under PBR. Empirical results show that the longer the utility operates under PBR the closer the X-Factor comes to the actual level of technical change across the industry. Put another way, the X-Factor is reduced over time. Since the base year is the basis by which future productivity is measured, the reasonableness of the X-factor depends in part on whether the base year reflects the current level of required resources. If the base year is underestimated, this in effect increases the X-Factor and potentially undermines the achievability of the PBR Plan."

68. FEI submits that the entire envelope of O&M expenditures needs to be considered to gauge the level of resources required by FEI at the outset of the PBR Plan, rather than cherry picking subcategories of O&M expenditures for different treatment. If the 2013 Approved O&M is to be reduced for sustainable savings as FEI has proposed, then, to be consistent, expenditures that were above 2013 Approved levels should also be incorporated into the 2013 Base O&M as FEI has proposed. The approach of cherry-picking subcategories of O&M above 2013 Approved levels artificially reduces the 2013 Base O&M, which would compromise the integrity of the PBR Plan and would be unfair to FEI.

(f) Future Efficiencies

69. A number of information requests explored the extent of future efficiencies that FEI may realize over the PBR Period.[84] While the purpose of these IRs is not always clear, the apparent thrust of some of these requests was to suggest that the 2013 Base O&M should be reduced for potential future efficiencies. Such a reduction would be unfair to the utility because it would change the basis on which the PBR Plan was proposed and would result in an artificial reduction of the 2013 Base O&M as it would not reflect the level of resources required by FEI at the outset of the PBR Plan. FEI explained as follows:[85]

> "FEI's delivery rates for the PBR Period will be calculated using the PBR formula, not using the individual departments' high level forecasts that were included in Section C of the Application. FEI will be managing the achievement of any savings

[84] E.g. Exhibit B-24, BCUC IRs 2.270.7 and 2.271.2.

[85] Exhibit B-24, BCUC IR 2.272.2.

> or incremental costs on a Company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. This latter point is particularly important because of the number of years that FEI has operated under PBR. Empirical results show that the longer the utility operates under PBR the closer the X-Factor comes to the actual level of technical change across the industry. Put another way, the X-Factor is reduced over time.
>
> The base year for a PBR is a starting point off of which future productivity is measured. The base should reflect the current level of required resources. If the Commission were to reduce the base for every potential productivity or savings that FEI is aware of, not only would this be asymmetrical, as there are many cost increases that FEI will encounter during the PBR period that it will be required to manage, but the result would be that FEI would have no opportunities remaining to achieve its significant productivity target during the PBR period, and would not have a reasonable opportunity to earn a fair return. This would be contrary to the intent of PBR, which is to incent the utility to find future productivity savings."

70. FEI reiterates that it is essential to the integrity of the PBR Plan that the 2013 Base Year Costs reflect the required level of resources at the outset of the PBR Plan. FEI's proposed PBR Plan is based in part on FEI's ability to realize potential future efficiencies in order to meet the productivity challenge embedded in the PBR formula. For example, the benefits of FEI's information technology Benefits Management practice were considered in determining FEI's proposed productivity improvement factor for the PBR Period. If the Commission were to reduce the 2013 Base O&M for future efficiencies such as this, this would compromise FEI's ability to meet the positive X-Factor and potentially FEI's right to a reasonable opportunity to earn a fair return.

(g) "Temporary Costs" or Whether 2013 Costs Continue into the PBR Period

71. A number of IRs explored whether costs incurred in 2013 would continue into the PBR Period, suggesting that, if not, then they should be removed from the 2013 Base O&M. FEI's responses to these IRs demonstrate that the costs in question would continue over the PBR Period:

(a) In the ES&ER department, FEI has explained how expenditures on the LTRP will continue over the PBR Period.[86]

(b) In the Information Technology department, in 2013, FEI experienced an increase of $600 thousand in non-labour for consulting backfills for IT, which are expected to continue.[87]

(c) In the Finance department, FEI has explained that certain costs for increased taxation services are expected to continue over the PBR Period.[88]

(d) FEI has explained that regulatory costs are expected to continue at 2013 levels even with the approval of the PBR Plan. If FEI were not under PBR, FEI would expect costs to increase rather than stay at existing levels as forecast.[89]

72. While these costs are in fact forecast to continue, this should not be the basis for the 2013 Base O&M. The question is not whether each dollar spent in 2013 will be required in 2014 or any year of the PBR Period. Rather, the 2013 Base O&M should reflect the level resources required at the outset of the PBR Plan. The controllable O&M costs over the PBR Period will then be determined in accordance with the PBR Plan.

(h) Exclusion of Certain Groups of Costs from PBR

73. IRs explored whether the Business Development and Market Development groups' costs should be excluded from PBR. The Commission's approved rates for 2012 and 2013, and for all prior years, have included the recovery of costs for these groups and have treated them no differently than other O&M costs. The Business and Marketing Development group costs should continue to be treated the same as other departmental O&M costs during the PBR Period. Each group is discussed in more detail below.

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86 Exhibit B-11, BCUC IR 1.99.1 and Exhibit B-24, BCUC IR 2.282.1.

87 Application, p. 170; Exhibit B-11, BCUC IR 1.115.1; Exhibit B-24, BCUC IR 2.290.

88 Exhibit B-24, BCUC IRs 2.291.7, 2.291.6.1 and 2.297.7.

89 Exhibit B-24, BCUC IR 2.292.

74. The Business Development group is responsible for identifying, developing and implementing new natural gas service offerings, including development of tariffs and seeking regulatory approval. Such service offerings include, but are not limited to, NGT services, low carbon product offerings, CNG and LNG for remote communities and off-grid applications and the development of high horsepower transportation applications such as ferries, locomotives and mine haul trucks. The costs captured in FEI's O&M for the Business Development group is in support of natural gas load growth initiatives, and does not include any costs for TES initiatives.[90] Pursuant to section 3 of Special Direction No. 5 to the British Columbia Utilities Commission, CNG and LNG services are now part of the natural gas class of service.[91]

75. In response to the question as to whether the Business Development group should be included in the 2013 Base to which the PBR formula is applied, FEI noted that the Business Development group is not a new group and has been part of FEI, by the specific name of Business Development or another name, for many RRA and PBR cycles and as such the costs incurred by this group have been approved by the Commission many times.[92] The costs of this group should continue to be treated the same now.

76. FEI elaborated on why the costs of this group should be included under the PBR formula, as follows:[93]

> "Business Development is responsible for identifying, developing and integrating new gas initiatives in order to adapt to changing market conditions. It is a strategic and proactive group that monitors the company's operating environment to explore and assess future customer needs and opportunities for natural gas and its use. Without such a forward-looking approach, FEI would be limited in its ability to provide new natural gas services and offerings for which our customers benefit. Further, FEI needs to be able to continue to innovate and adapt to changing market conditions and employ opportunities to mitigate potential negative impacts to existing and future ratepayers.

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90 Exhibit B-11, BCUC IR 1.110.2.1.

91 B.C. Reg. 245/2013, dated November 28, 2013. Filed under Tab 1 of Exhibit B-1-5.

92 Exhibit B-11, BCUC IR 1.110.2.

93 Exhibit B-11, BCUC IR 1.110.2.

> For clarity, as it pertains to cost allocation methodology, as new service offerings are being developed these are brought forward to the Commission for approval and it is through these regulatory proceedings that appropriate cost allocation methodologies are approved by the Commission. This has been the case with new service offerings, such as RNG, NGT and prior to the AES Decision, the AES offerings. With respect to new future business initiatives, it is not reasonable for FEI to provide a proposal of new business activities to be developed and offered to customers in future years since these have not yet been identified. When FEI next files a comprehensive rate design application along with supporting COSA models, a review of how the cost allocation related to these services integrates with the overall cost allocation methodologies employed, will be reviewed.
>
> FEI submits that there is no justification to treat the activities of the Business Development group in a different manner than any other department. As the business development activities that benefit natural gas ratepayers are ongoing activities which often require development over a period of time, often exceeding at least one year, in order to move through the various phases of feasibility, implementation and management, the cost of the Business Development group should be included in the base to which the O&M formula is applied during the PBR period. It would not be appropriate and would incur unnecessary complexity, to exclude the cost of the Business Development group from the revenue requirements in the year that they are incurred and have FEI request recovery of the actual Business Development costs at the Annual Review, for recovery in following year. In addition, FEI requires stability in personnel and budget planning and the Business Development group should be treated no differently than any other part of the company that supports FEI's sustainment, growth and customer offerings."

77. For these reasons, the Business Development group costs should continue to be treated the same as other department O&M costs.

78. The Market Development group is responsible for service process improvements, and the evaluation of market conditions, emerging gas technologies, and upcoming changes in codes and regulations on future natural gas use. The employees in the Market Development group are also responsible for the forecasting of short term and long term energy demand and customer gas use, along with the development of the company's LTRP.[94]

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94 Application, p. 154.

79. FEI was asked: "If the FEI cannot provide a clear and concise description of the methodology to allocate costs to the new customer initiatives, would it be appropriate to exclude the cost of the Market Development area from the revenue requirements in the year that they were incurred and have FEI request recovery of the actual Market Development costs at the Annual Review, for recovery in following year (i.e. 2014 Market Development cost would be reviewed at the 2014 Annual Review and recovered in 2015 rates)? Please explain why, or why not."[95] The question apparently assumed that the initiatives in the Market Development group required a methodology to allocate costs to such new customer initiatives. As FEI has explained, the new customer initiatives and rate offerings developed by the Market Development group are developed and implemented for the traditional base of natural gas customers and benefit such customers.[96] It is therefore appropriate for the costs of these initiatives to be recovered from customers similar to other O&M costs. To the extent the Commission is concerned about biomethane or NGT initiatives, these are addressed above.

80. The Market Development group is also responsible for, among other activities, short and long term energy forecasting, the preparation and compilation of the Long Term Resource Plan, preparation and filing of the System Extension Test, and EEC Reporting.[97] These activities are items that FEI has been specifically directed to do by the Commission. It is therefore appropriate that these costs be treated similar to other O&M costs. FEI requires stability in personnel and budget planning, and the Market Development group should be treated no differently than other parts of the company that supports FEI's sustainment, growth and customer offerings.[98]

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[95] Exhibit B-24, BCUC IR 2.286.4.1.

[96] Exhibit B-24, BCUC IRs 2.286.3 and 2.287.1.

[97] Exhibit B-24, BCUC IR 2.286.1.

[98] Exhibit B-24, BCUC IR 2.286.4.1.

81. Further, under PBR principles, the costs of the Market Development and Business Development groups should be included in the formula-based O&M. FEI explained as follows with respect to the Market Development group:[99]

- The Market Development O&M costs fall into the category of costs that are controllable by the Company. A basic structural principle in the proposed PBR is to incorporate incentives into the cost of service elements that are controllable by the Company and treat non-controllable costs on a pass through basis. With respect to O&M expenses the items that are removed from the O&M formula are non-controllable cost items such as pension and insurance costs. Treating controllable cost items such Market Development O&M costs as proposed in the question would mark a departure from this principle.

- Another general principle of PBR is to adopt higher level formulas for setting rates or cost components in rates and to take the focus off line item cost management as is more a characteristic of cost-of-service regulation. The utility under PBR has more freedom to adapt and optimize its operations (within the constraints of meeting service quality requirements). Removing Market Development O&M costs from the O&M formula and reforecasting them each year as proposed would be contrary to this aspect of PBR.

- Setting aside the Market Development O&M costs for special treatment would also run counter to the goal of streamlining the regulatory process under PBR. Regulatory burden would be added to review and approve this item on a yearly basis.

- Lastly, the inference in the question suggests that the activities of the group are not prudently incurred and as such should not be included in regular O&M. FEI does not agree with this inference. The Market Development group, and the activities they perform, has been part of the FEI O&M and activities through many RRA applications. It is not a new group or activity. To suggest that as part of a PBR application these activities should not be performed or if so, at risk to the shareholder until application is sought to recover costs is contrary to the regulatory compact.

[99] Exhibit B-24, BCUC IR 2.286.4.1.

82. For the reasons above, FEI submits that the costs of the Business Development and Market Development groups are properly included within the PBR formula.

PART FOUR: 2013 BASE CAPITAL

A. Overview of the 2013 Base Capital

83. Pursuant to the PBR Plan, the rate base used to determine rates during the PBR Period will make use of a formula based approach for calculating FEI's Sustainment, Growth and Other Capital expenditures.[100] The objective of this classification is to include all controllable capital components of total rate base in the formula, which excludes those components of rate base that do not relate directly to regular capital expenditures. Expenditures for CPCNs would continue to be reviewed and approved by the Commission through separate regulatory processes.[101]

84. As discussed above with respect to the 2013 O&M Base, the 2013 Base Capital is the starting point from which future productivity is measured and should reflect the level of required resources at the outset of the PBR Plan. FEI will be managing the achievement of any savings or incremental costs on a company-wide basis as part of the overall challenge FEI has in meeting its O&M and capital targets under a PBR Plan that includes a large and significant X-Factor. The integrity of the PBR Plan and FEI's right to a reasonable opportunity to earn a fair return therefore depends on the 2013 Base Capital being set to reflect FEI's level of required resources at the outset of the PBR Plan. Otherwise, if the 2013 Base Capital is set below this level, the targets under the PBR Plan will be unfairly and systematically increased, potentially denying FEI its right to a reasonable opportunity to earn a fair return over the term of the PBR Period.

85. FEI has used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision ("2013 Approved Capital") as the starting point for the capital formula.[102] Similar to the methodology used to arrive at the 2013 O&M Base, adjustments are made to the 2013 Approved Capital to arrive at the 2013 Base Capital. These include:

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[100] The treatment of capital expenditures under the PBR Plan is discussed in Section B6.2.5 of the Application.

[101] Application, p. 203.

[102] Application, Section B6.2.5.1, as updated in Exhibit B-1-5.

- Adjustments to include the capital portion of 2013 Actual “non-controllable” items that are held in deferral accounts in 2013 (PST and Pension amounts); and

- Accounting changes that reclassify items from O&M to capital.

86. The goal of these adjustments is to determine the appropriate starting point or base for capital expenditures in the upcoming PBR period. The calculation of the 2013 Base Capital is shown in Table B6-6 on page 61 of the Application, as amended in the February 2014 Evidentiary Update. The adjustments to the 2013 Approved capital are as follows:

(a) An adjustment is made for two deferrals of capital during 2013, as follows:

- $1.999 million in the Tax Variance deferral account relating to PST on capital.

- $1.311 million in the Pension and OPEB Variance deferral account related to capital expenditures.

(b) The 2013 Base Capital includes adjustments for two accounting changes: the allocation of retiree pensions/OPEBs and the capitalization of annual software costs. These changes reallocate costs from O&M to capital. The changes are described in Section D3.1 of the Application and are considered below in Part 5 of this Submission.

(c) The 2013 Base Capital has been restated to show vehicle purchases that will start in 2013, at the 2013 Approved amount for vehicle lease additions of $2.860 million. This adjustment is a reclassification of what was considered a capital addition (the vehicle capital lease) to a capital expenditure (an upfront payment for the purchase of a vehicle) and therefore does not affect total capital additions. This adjustment is described further in Section D3 Accounting Policies and discussed in Part 5 of this Submission below.

87. FEI has not adjusted the 2013 Approved Capital for sustainable savings as FEI's required level of resources was not below the 2013 Approved Capital, as confirmed by the projected and actual capital expenditures over this period. As described in Section C4 of the Application, the total of the 2012 Actual and the amounts projected by FEI for 2013 (the "2013 Capital Projection") were very close to the amounts approved in the 2012-2013 RRA Decision. 2013 Actual capital expenditures were $6.4 million higher than the 2013 Capital Projection, after removing the Biomethane interconnect facilities and, overall, the combined 2012 and 2013 Actual spending was $5.3 million above the 2012 and 2013 Approved.[103]

88. Excluded from the capital expenditures subject to the formula are the following:

(a) *Biomethane upgraders and future interconnect costs*. Biomethane upgraders and future interconnect costs are not recovered through the delivery rate, but rather through a separate rate setting process, i.e. the setting of the BERC.

(b) *CNG and LNG fuelling stations*. NGT fueling station capital costs are associated with incremental NGT revenues that are tracked outside the PBR formula and are recovered through a separate rate setting process.

(c) *The future Tilbury expansion costs*. Because FEI is still in the early stages of project development, the expansion of the Tilbury facility and any net impact on the revenue requirement will be discussed in future FEI annual review filings.[104]

(d) *CPCNs*. CPCNs are subject to separate regulatory processes.

89. Consistent with past practice, the impact of CPCNs will not be included in rates until FEI has received Commission approval for such projects through separate processes.[105]

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[103] Application, p. 61, as revised by Exhibit B-1-5.

[104] Exhibit B-1-5, p. 6.

[105] Application, p. 61, as revised by Exhibit B-1-5.

B. Issues Raised

90. The subsections below will address the issues raised with respect to the 2013 Base Capital.

(a) Subcategories of Capital Expenditures Below Approved

91. A number of information requests suggested that capital expenditures below 2013 Approved Capital in certain categories should be used to set the 2013 Base Capital instead of the 2013 Approved amounts. For example, it was suggested that the 2013 Projected expenditures for mains and meters (a subcategory of Growth Capital expenditures) should be used instead of the 2013 Approved amount.[106] In principle, if 2013 Approved amounts are to be reduced for expenditures below approved levels in selected categories, then they should also be increased for expenditures above approved levels in other categories. FEI explained why its approach is reasonable as follows:[107]

> "FEI recognized that the 2013 base for the 2014-2018 formula should be a number that has undergone a full review in a public hearing. For that reason, FEI used the 2013 approved Capital Expenditures in Order G-44-12 as the starting point for the Capital formula, rather than 2013 projected expenditures. Overall 2013 spending in aggregate is projected to be approximately $6.5 million higher than 2013 approved amounts. As such, using projected expenditures for 2013 as the starting point for the Capital formula would have resulted in a higher 2013 base than that proposed in the PBR Plan.
>
> With capital spending, particularly for mains projects which are often discrete in nature, there may be timing issues for project completions that lead to fluctuations in capital additions from year to year. Under-spending in one year does not imply a permanent reduction that would be carried to the subsequent years.
>
> In addition to the issue discussed above, the concept of re-setting the base as proposed in the question is contrary to the general intent of establishing a PBR in the first place. The base levels in the PBR capital formulas and the I-X escalation factors are intended to establish an appropriate reference level of capital

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[106] Exhibit B-26, BCUC PBR IR 2a.15.3.

[107] Exhibit B-26, BCUC PBR IR 2a.15.3.

> spending from which FEI will seek to find efficiencies for the term of the PBR. If the base is to be reset because expenditures in a particular category, such as mains capital, are under-spent in a particular year, this would diminish the incentive power of the PBR Plan significantly and reduce the motivation to pursue efficiencies for the longer-term benefit of customers."

92. All components of capital expenditures need to be considered to take into account FEI's required level capital investments at the outset of the PBR Plan. A fair assessment of FEI's required investment in Growth capital, for instance, should take into account the required expenditures both in mains and meters and in services.[108] Further, as explained above, any underspending may be due to timing issues for project completions, and not reflect a permanent reduction in capital requirements.

93. Similarly, FEI was asked if the 2013 Base Capital should be reduced for the expenditures in the subcategory of Transmission System Reinforcements that were below 2012 and 2013 Approved.[109] Again, this suggestion ignores the principles on which the 2013 Base Year Costs should be set as discussed above, and instead attempts to cherry pick categories of expenditures below 2013 Approved to artificially reduce the 2013 Base Capital. FEI submits that the use of the 2013 Approved Capital is a principled basis on which to set the 2013 Base Capital and should be approved.

(b) Expenditures Above Approved

94. Other information requests inquired into whether expenditures above 2013 Approved Capital for the Regulator Evergreening project should be removed from the 2013 Base Capital.[110] As discussed in the response to these IRs, FEI spent more than forecast and approved on Regulator Evergreening costs in 2012 and 2013. However, the 2013 Base Capital is based on the 2013 Approved Capital. As such, any spending above 2013 Approved Capital is not included.

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[108] Exhibit B-26, BCUC PBR IR 2a.15.5.1.

[109] Exhibit B-11, BCUC IR 1.153.1.

[110] Exhibit B-11, BCUC IR 1.154.1 and Exhibit B-24, BCUC IR 2.297. See the Application, pp. 220-221, regarding the Regulator Evergreening capital costs.

(c) Historical Costs

95. Information requests explored trends in historical Sustainment Capital costs, suggesting that the 2013 Base Capital in this category of expenditures should be reset on the basis that the expenditures from 2004 to 2010 represent the "true costs for its normal course of business in this area".[111] The measure of the "true costs" of its business that FEI has proposed is the amount approved by the Commission to be just and reasonable. The 2013 Approved Capital demonstrates that the Commission has reviewed and approved increases in the level of expenditures over the past years based on evidence presented and tested in revenue requirement proceedings. FEI's submissions on this point are similar to those made in Part 3 above with respect to the 2013 Base O&M. Briefly, resetting the 2013 Base Capital with reference to historical trends is inappropriate for a number of reasons:

(a) The Commission has already approved FEI's capital costs for 2012 and 2013 in its 2012-2013 RRA Decision. There is no need to reanalyze the need for capital expenditures that have already been previously justified by FEI and approved by the Commission. Resetting the 2013 Approved Capital would be inconsistent with the Commission's own decisions. No facts or circumstances have changed that would justify such inconsistent decisions.

(b) Present capital requirements are markedly different than the capital requirements in past years. Specifically, the current needs of the system are greater than what they were from 2004 to 2009.[112] Since 2004, system conditions, code requirements, asset management expertise and sustainment requirements have changed.[113] Efficiencies achieved during the previous PBR period managed to control increases in expenditures, but did not reduce the long-term needs of the system.[114] Notably, FEI's assets are aging and FEI has

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[111] Exhibit B-24, BCUC IR 2.296.6.4.

[112] Exhibit B-24, BCUC IRs 2.296.6, 2.296.6.1, 2.296.6.2, 2.296.6.3, 2.296.6.4, and 2.296.6.6.2.

[113] Exhibit B-24, BCUC IR 2.296.6.3.

[114] Exhibit B-24, BCUC IRs 2.296.6.1 and 2.296.6.3.

implemented the Long Term Sustainment Plan which has resulted in an improved understanding of asset condition.[115] A number of programs and projects have been identified that are mandatory to maintain safe, reliable service of the natural gas delivery system.[116] For these and other reasons discussed in FEI's IR responses, the facts demonstrate that the 2013 Base Capital is justifiably higher than the expenditures from 2004-2009.

(c) The theory of PBR and the basis of the PBR Plan requires that the 2013 Base Capital be set on the requirements of the utility for that year using cost of service principles, which is why the 2013 Approved Capital - determined by the Commission in a full oral hearing - is the most reasonable starting place. Resetting the 2013 Base Capital to the level of expenditures in 2004-2009 undermines the PBR Plan by "baking in" an arbitrary level of efficiencies into the 2013 Base Capital. This would have the potential effect of denying FEI's right to a reasonable opportunity to earn a fair return.

96. In short, setting the 2013 Base Capital using the 2013 Approved Capital takes into account the historical cost increases that the Commission has reviewed and approved over the years and is consistent with the principles of PBR.

(d) Future Costs

97. Some information requests appeared to explore whether certain capital expenditures were required throughout the PBR Period with the implicit suggestion that the 2013 Base Capital should be reduced. For example, information requests explored expenditures on Meter Recalls and Exchanges which are part of the Sustainment Capital portfolio.[117] As demonstrated by FEI's evidence on these expenditures, the 2013 Approved Capital reflects the 2013 cost of service and, given the forecasts over the PBR term, the 2013

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[115] See Exhibit B-1-1, Appendix C3 for a report on FEI's Long Term Sustainment Plan.

[116] Application, pp. 210-216; Exhibit B-24, BCUC IR 2.296.6.1.

[117] Exhibit B-11, BCUC IR 1.155 and Exhibit B-24, BCUC IR 2.299.

Base Capital will provide a challenge to FEI over the PBR period.[118] FEI has also explained why Regulator Evergreening project costs will continue to be required over the PBR Period.[119] Under a PBR Plan, however, controllable costs over the PBR Period are to be set pursuant to the PBR formula, not on a cost of service forecast basis.

98. As FEI has emphasized, it is central to the PBR Plan that the 2013 Base Capital be based on the resources required by the utility in the base year, not over the PBR Period. The level of productivity that FEI is expected to achieve compared to the 2013 Base Capital is set by the PBR formula. Reducing the 2013 Base Capital for potential savings would be asymmetrical, as there are many cost increases that FEI will also encounter during the PBR Period that it will be required to manage. Furthermore, the result would be that FEI would have no opportunities remaining to achieve its significant productivity target during the PBR Period This would be contrary to the intent of PBR, and would potentially deny FEI its right to a reasonable opportunity to earn a fair return.[120]

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[118] Application, pp. 218-220; Exhibit B-11, BCUC IR 1.155 and Exhibit B-24, BCUC IR 2.299.

[119] Application, p. 220; Exhibit B-11, BCUC IR 1.156 and Exhibit B-24, BCUC IR 2.302.

[120] Exhibit B-24, BCUC IR 2.272.2.

PART FIVE: FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

99. In addition to the 2013 Base Year Costs which will be used to determine future costs under the PBR formula, FEI's delivery rates will be set to recover items that are not tracked under the PBR formula. These include interest expense, return on equity, taxes, pension and OPEB expenses and insurance costs, depreciation and amortization, CPCN expenditures and other deferred charges.[121] These items outside of the PBR formula are discussed in Section D of the Application.

100. FEI's forecast of financing costs, approved return on equity, and tax expenses for 2014 is described in Sections D1 and D2 of the Application. Based on FEI's review of the information requests, no material issues were raised in the proceeding with respect to the financing and tax expenses forecast for 2014. Under FEI's PBR Plan, FEI will be reforecasting these expenses each year of the PBR Period in the Annual Review process.

101. Section D3 of the Application sets out FEI's accounting policies and procedures which are expected to remain in place for the course of the PBR Period. FEI is requesting approval of several changes to accounting policies. These include changes to accounting policies, such as capitalization of software costs, that result in a different allocation of certain costs between O&M and capital as referenced above in respect to setting the 2013 Base Year Costs. Other accounting policies and procedures canvassed in Section D3 include, for example, depreciation, shared and corporate service, and capitalized overhead.

102. Section D4 of the Application describes FEI's request for approval of 2 new rate base deferral accounts, changes to existing rate base deferral accounts, and the discontinuance of 18 deferral accounts that are no longer required.[122] FEI also has a number of deferral accounts for which no changes are sought and which will continue as previously approved.[123] This section was updated by Exhibit B-1-3 and more recently by the February 2014 Evidentiary

[121] Application, Section 6.3.2, pp. 68 to 70.

[122] Application, pp. 290-309, as updated by Exhibit B-1-3, B-15 and B-1-5.

[123] Application, p. 290, Footnote 60.

Update, which updated the balances in the deferred charges to reflect 2013 Actual additions, withdrew FEI's request to discontinue the CNG and LNG Recoveries Deferral Account, and requested the discontinuance of the Fueling Station Variance Account.[124] An updated list of FEI's requests with respect to deferral accounts is provided on page 6 of the Application, as updated by the February 2014 Evidentiary Update.

103. The following subsections of this Submission will discuss the accounting policies and deferrals that were the subject of material information requests during the proceeding. FEI notes the following:

(a) The discontinuation of the Depreciation Variance Deferral Account is discussed below under Accounting Policies under the heading of Depreciation.

(b) The TESDA Overhead Allocation Variance Account is addressed in Part 7 of this Submission below.

(c) The amortization period of the EEC deferral accounts is addressed in Part 8 of this Submission below.

A. Accounting Policies

(a) Discontinuance of US GAAP to Canadian GAAP Reconciliation

104. FEI is requesting to discontinue the US GAAP to Canadian GAAP reconciliation starting with the 2013 BCUC Annual Report. Preparation of the reconciliation is no longer in the public interest for a number of reasons. As stated in the Application:[125]

> "In Order G-117-11 the BCUC approved the adoption of US GAAP by FEI for regulatory accounting and reporting purposes effective January 1, 2012. As part of that order, the Commission requested an annual reconciliation from US GAAP back to Canadian GAAP. FEI has provided this reconciliation in the 2012 BCUC Annual Report Tab 17. This reconciliation provides a link back to Canadian GAAP

[124] Exhibit B-1-5, p. 4-6.

[125] Application, p. 264.

> which existed prior to 2012. However, FEI no longer maintains specific accounting records in compliance with pre-2012 Canadian GAAP since they are not used for any other reporting purpose. It will therefore become increasingly complicated to complete this reconciliation on a prospective basis. Further, the effects of US GAAP for regulatory accounting and reporting, which related to pension and other post-employment benefits, are now embedded and transparent within the Application as reflected in Section D4 Deferrals. Given these developments, FEI does not see any need to continue with the reconciliation and believes that the US GAAP accounting changes for FEI should be treated the same as any other accounting policy change that has been previously implemented and communicated in previous applications."

105. The reconciliation should be also discontinued as it could be misleading as it may not identify the true differences that would exist if pre-changeover Canadian GAAP had continued to be a financial reporting option.[126] FEI explained that beginning in 2012 pre-changeover Canadian GAAP was withdrawn by Canadian standard setters and ceased to exist as a financial reporting option. Therefore, to the extent that a difference from pre-changeover Canadian GAAP arises from a change in accounting guidance by US standard setters, it would not be possible to determine whether a similar accounting guidance change would have occurred under Canadian GAAP if this financial reporting option had continued to exist.

106. In summary, FEI submits that the reconciliation is no longer required, is potentially misleading and should be discontinued.

(b) Allocation of Retiree Pension and OPEBs

107. FEI is requesting approval to include both the current service and retiree portion of pension and OPEB expenses in benefit loadings. In 2010, FEI separated the current service portion and retiree portion of both pension and OPEB expenses. This change was made in anticipation of the adoption of International Financial Reporting Standards ("IFRS") which allowed for the capitalization of only direct expenditures into benefits loadings and capital. As a result of the adoption of US GAAP starting January 1, 2012 and the plan to continue using US GAAP as the basis of financial and regulatory accounting during the PBR Period, FEI is

[126] Exhibit B-24, BCUC IR 2.316.2.

requesting to include both the current service and retiree portion of pension and OPEB expenses in benefit loadings, consistent with the practice prior to 2010. For the 2013 Base Year Costs, this has the impact of shifting $930 thousand from O&M to capital.[127]

108. The US GAAP guidance that supports FEI's proposed accounting treatment is as follows:[128]

> "ASC 715-30-35-3, Compensation-Retirement Benefits, Defined Benefit Plans-Pension, refers to Net Benefit Cost (referred to specifically as net periodic pension cost in US GAAP below) as a "homogeneous amount." Although the components of Net Benefit Cost are measured separately, they should be reported together as a single pension expense on the face of the financial statements. Accordingly, it would not be appropriate to disaggregate the individual components of the pension cost (e.g., service, cost, interest cost, amortization of net gains and losses) and report them separately in the financial statements."

109. The proposed accounting treatment is being used by FBC, and has been reviewed and accepted by FBC's auditors.[129]

110. While the proposed change would reduce O&M volatility to an extent, this was not FEI's goal in seeking approval of this change. Rather, the primary intent of the proposed change in accounting treatment is to better align with the relevant US GAAP guidance, and to obtain consistency in accounting policy with FBC.[130]

111. FEI's proposal for the treatment of the retiree portion of pension and OPEB expenses is therefore consistent with US GAAP, reverts to the treatment used by FEI prior to consideration of a transition to IFRS, and is consistent with the accounting policy of FBC. As such, FEI respectfully requests that this accounting change be approved.

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[127] Application, p. 285 and Exhibit B-11, BCUC IR 1.164.

[128] Exhibit B-24, BCUC IR 2.317.2.

[129] Exhibit B-24, BCUC IR 2.317.2.

[130] Exhibit B-24, BCUC IR 2.317.4.

(c) Capitalization of Annual Software Costs

112. FEI is proposing to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. The costs allocated to capital using this methodology are to fund only the upgrade component of the annual costs which extend the life of the affected software assets. Annual software costs in regards to support and maintenance continue to be an operating expense.[131] FEI has estimated the percentage allocations of capitalized software, e.g. 30% of Microsoft annual desktop software costs, based on a combination of the expected benefits to be derived from the software and the feedback provided by FEI's external vendors.[132] The impact of this change to the 2013 Base Year Costs is to shift $1.8 million of O&M to capital.[133]

113. This change in methodology was proposed because it results in an allocation of O&M and capital that more accurately reflects the capital nature of annual software costs and is better aligned with US GAAP.[134] US GAAP allows for costs associated with upgrades to be capitalized because the upgrades result in either enhanced functionality of the software or extensions to the useful life of the existing software. ASC 350-40, Internal – Use Software (Intangibles – Goodwill and Other) states the following:[135]

> "25-7 In order for costs of specified upgrades and enhancements to internal-use software to be capitalized…it must be probable that those expenditures will result in additional functionality.
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> 25-11 External costs incurred under agreements related to specified upgrades and enhancements shall be expensed or capitalized…If maintenance is combined with specified upgrades and enhancements in a single contract, the cost shall be allocated between the elements…"

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[131] Application, p. 265.

[132] Exhibit B-11, BCUC IR 1.165.5.

[133] Application, p. 265.

[134] Exhibit B-24, BCUC IRs 2.318.4 and 2.318.5.

[135] Exhibit B-11, BCUC IRs 1.165.1 and 1.165.1.1.

114. The proposed change in capitalization methodology is better aligned with US GAAP guidance as the upgrade costs to be capitalized result in either enhanced functionality of the software or extensions to the useful life of the existing software.[136] FEI has provided examples of software that have this effect.[137] Generally, software is kept current and useful through continual upgrades and the annual investment in these upgrades generally extends the life of the software asset many years after the original investment is fully depreciated. Without these upgrades complete software replacements would need to be done regularly with a higher capital cost and increased business disruption.[138]

115. The proposed treatment is employed by FBC and has been reviewed and accepted by FBC's auditors.[139] In summary, FEI's proposed accounting change results in a better alignment with US GAAP and the capital nature of annual software costs and is consistent with the treatment of FBC. FEI therefore submits that the change is just and reasonable and respectfully requests that it be approved.

(d) Purchases of Vehicles

116. For historical reasons that FEI has explained in response to information requests, FEI currently acquires the majority of its fleet from a 3rd party lessor.[140] FEI is seeking approval to change this practice and transition to an owned fleet. This is a more cost-effective option, with the lowest rate impact to ratepayers, and would be consistent with the practice of FEVI, FEW and FBC which currently purchase their vehicles. FEI's change from a lease to own approach for vehicle acquisition will align all the FortisBC companies and therefore reduce the administrative burden that currently exists within Fleet Management associated with using two

[136] Exhibit B-24, BCUC IR 2.318.3.
[137] Exhibit B-24, BCUC IRs 2.318.6 and 2.318.7.
[138] Exhibit B-11, BCUC IRs 1.165.2 and 1.165.4.
[139] Exhibit B-24, BCUC IR 2.318.2.
[140] Exhibit B-11, BCUC IR 1.166.1.

distinct processes.[141] Purchasing vehicles would also ensure that FEI is not exposed to risks of delay in the supply of vehicles as was experienced in 2009 during the credit crisis.[142]

117. FEI completed an analysis on its current fleet of vehicles, with the review intended to ascertain whether FEI should continue to lease its vehicle fleet or transition to an owned fleet. FEI's analysis indicates that FEI should transition the vehicle fleet to an owned status as the current leased vehicles are retired. This option has the lowest present value cost of service (approximately $3 million over a 20 year analysis period), and therefore a lower rate impact to customers. FEI has provided the detailed analysis in response to BCUC IR 1.166.6.[143] That analysis concludes that based on the three major components that affect the cost of service, the lowest cost of service and lowest cost to rate payers would be to transition FEI's current leased fleet to an owned status as the existing vehicles are retired and replaced.[144]

118. This decision to purchase vehicles does not change the regulatory treatment. Since the existing vehicle lease is treated as a capital lease for financial and regulatory purposes, the change only results in what was previously shown as a capital addition now being shown as a capital expenditure (an actual cash outlay) in the financial schedules.[145] Consistent with FEVI, FEW, and FBC, the vehicles that are being purchased are estimated to have an average 8-year service life, resulting in a depreciation rate of 12.5 percent for this asset class.[146] The O&M and capital treatment is similar for leasing or owning and there is no difference to ratepayers in the rate base treatment of the vehicles.[147]

119. For the reasons above, FEI submits that the proposed change is in the best interest of ratepayers and is just and reasonable. FEI respectfully requests that it be approved.

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[141] Exhibit B-11, BCUC IR 1.166.2.
[142] Exhibit B-11, BCUC IR 1.166.3.
[143] Exhibit B-11, BCUC IR 1.166.6.
[144] Exhibit B-11, BCUC IR 1.166.6.
[145] Application, p. 265-266; Exhibit B-11, BCUC IR 1.166.8.
[146] Application, p. 266; Exhibit B-11, BCUC IR 1.166.10.
[147] Exhibit B-11, BCUC IR 1.166.9; Exhibit B-24, BCUC IRs 2.319.4, 2.319.5 and 2.319.8.

(e) Depreciation

120. FEI is proposing two changes relating to depreciation:

(a) to calculate depreciation expense commencing at the beginning of the year following when the asset is placed into service; and

(b) to discontinue the Depreciation Variance deferral account.

121. Calculating depreciation expense at the beginning of the year following when the asset is placed into service is the method that was followed and approved as part of the 2004-2007 PBR (extended for 2008 and 2009). This is in comparison to the current practice of depreciation commencing at the time the asset is placed into service.[148] The approval from the Commission for the change in the timing of the commencement of depreciation was granted starting January 1, 2010 as part of FEI's (then Terasen Gas Inc.) 2010-2011 RRA in order to comply with IFRS which FEI was anticipating adopting at the time of submitting the application in 2009.[149] Subsequently, the Commission has granted approval for FEI to adopt US GAAP which allows depreciation expense to commence at the beginning of the year following when the asset is placed into service. Therefore, the reason for the change that existed in 2010 no longer exists.

122. Prior to 2010, depreciation expense commenced at the beginning of the year following when the asset is placed into service in order to minimize any variances in depreciation expense related to the timing or amount of capital being placed in service as compared to forecast. This result was also achieved in the years 2012 and 2013, when rates were set using a forecast cost of service, with the Depreciation Variance deferral account. [150]

123. The Depreciation Variance deferral account was specifically approved for the 2012-2013 test period only. Therefore, this account discontinues by the terms of its original

[148] Application, p. 267.

[149] Application, p. 304; Exhibit B-8, CEC IR 1.76.1.

[150] Application, p. 304-305.

approval on January 1, 2014. For this reason, FEI has not listed the discontinuance of this account in its list of approvals sought.[151]

124. Under PBR, the continued use of the Depreciation Variance deferral account would significantly reduce any incentive to find efficiency savings in capital. The ability to achieve these savings is a key component of this PBR Plan. Under FEI's proposed approach the variance in depreciation expense will be driven by the formula vs. actual capital, which provides the appropriate incentive to pursue efficiency savings in capital. In FEI's proposed PBR Plan, the capital incentive is made up of three components – earned return, depreciation and taxes. A Depreciation Variance deferral account would take away all of the incentive related to capital with the exception of the small earned return component.

125. Discontinuing the Depreciation Variance deferral account retains the incentive to find efficiencies in capital costs under the PBR Period, which is a key component of the PBR Plan design. This incentive is present in PBR plans that incorporate capital as part of the formula, and is supported by PBR theory for both price cap and revenue cap type models.[152] The proposed change in timing of depreciation and the discontinuance of the Depreciation Variance deferral account is therefore necessary for the proper functioning of the PBR Plan.[153]

126. In summary, the requested changes are consistent with US GAAP, simpler due to the discontinuation of the Deprecation Variance deferral account, and necessary for the proper functioning of the PBR Plan. As such, FEI submits that the proposed changes to the treatment of depreciation are just and reasonable and respectfully requests that they be approved.

(f) Shared and Corporate Services

127. Except with respect to executive cross charges to and from FBC, FEI is applying to continue the methodologies for allocating costs from Fortis Inc., FortisBC Holdings Inc. ("FHI")

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[151] Application, p. 304.

[152] Application, p. 304.

[153] Exhibit B-24, BCUC IR 2.321.1.

or any other Fortis entity. Information requests during the proceeding centred on the corporate services allocation from Fortis Inc. to FHI and FEI's request to allocate executive cross charges to and from FBC using the Massachusetts formula. These topics are addressed below.

Fortis Inc. Corporate Services Allocation

128. The Fortis Inc. corporate services costs are allocated to FHI using the Asset Allocation method. The Asset Allocation method is the most appropriate way to allocate Fortis Inc.'s operating costs to its subsidiaries as the nature of the services being provided by Fortis Inc. are more correlated with the net investment required of Fortis Inc. in its utilities.[154]

129. Information requests asked why the Massachusetts formula was not used to allocate Fortis Inc. costs to FHI. The Massachusetts formula uses three main drivers for allocating costs, operating revenue, payroll and average net book value of capital assets plus inventories. Fortis Inc. does not use the Massachusetts method for allocating its costs to FHI as two of these main drivers are not representative of the services provided, as explained further below:[155]

(a) Revenue is not a representative cost driver as revenue across the Fortis utilities is different and not directly comparable. For example, certain utilities such as FortisAlberta, may only charge customers for distribution services, which would result in a disproportionately low allocation of costs to this utility, while other utilities would receive a disproportionately high allocation of the costs as revenues include both distribution services and the cost of energy supply. This is particularly exaggerated in periods when customer rates and related revenues reflect the pass-through to customers of rising purchased power, gas and fuel prices.[156]

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[154] Exhibit B-6, BCPSO 1.34.5.2. Note, however, that the allocation of the Fortis Inc. fee to FHI using net assets compared to using the Massachusetts formula are comparable with only slight differences. (Exhibit B-6, BCPSO IR 1.34.5.3).

[155] Exhibit B-6, BCPSO IR 1.34.5.2.

[156] Exhibit B-6, BCPSO IR 1.34.5.2.

(b) Payroll is also not an appropriate cost driver as the nature of the services from Fortis Inc. to its subsidiaries is not related to the payroll costs in its utilities. The services Fortis Inc. provides to FHI includes provides executive services, treasury and taxation services, investor relations, financial reporting, internal audit and board of directors services. These types of services are broad and focused on strategic direction, leadership, risk management and oversight and, as such, are not related to the payroll of the subsidiaries.[157]

130. As the nature of the services being provided by Fortis Inc. is more correlated with the net investment required of Fortis Inc. in its utilities, the Asset Allocation method continues to be the appropriate way to allocate Fortis Inc.'s operating costs to its subsidiaries.[158]

Executive Cross Charges to and from FBC

131. Beginning on January 1, 2014 for the term of the PBR Period, FEI is proposing that the executive cross charges between FEI and FBC be allocated using the Massachusetts formula, instead of management estimates of time allocations as used in previous years. The Massachusetts formula is a composite allocator and using this formula estimates the amount of time and effort that each of the executives spend, on average, on each of the entities. The Massachusetts formula is well established and generally accepted in British Columbia and other regulatory jurisdictions. Allocating the fully loaded Executive labour costs based on the Massachusetts Formula will allow for a more streamlined and efficient approach of allocating the costs, while ensuring an appropriate and transparent allocation methodology.[159]

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[157] Exhibit B-6, BCPSO IR 1.34.5.2; Application, p. 281.

[158] Exhibit B-6, BCPSO 1.34.5.2. Note also that the allocation of the Fortis Inc. fee to FHI using net assets compared to using the Massachusetts formula are comparable with only slight differences. (Exhibit B-6, BCPSO IR 1.34.5.3.)

[159] Application, Section D3.6; Exhibit B-6, BCPSO 1.34.2; Exhibit B-24, BCUC IR 2.329.

132. FEI explained the reason for the change as follows:[160]

> "The Massachusetts formula is the most appropriate method to allocate Executive Management costs between FEI and FBC as it is will result in an appropriate and accepted allocation, while allowing for increased cost effectiveness of the approach (i.e. reduced administrative effort). The Massachusetts formula is a cost sharing methodology that is well established and generally accepted in other regulatory jurisdictions. The Massachusetts formula is generally utilized when there is substantial sharing of costs between entities.
>
> Prior to 2012, not all the executives for FBC and FEI had joint responsibilities in both companies and, as such, allocating Executive Management costs based on the Massachusetts formula would have been less relevant. However, with all the executives for FBC and FEI having joint responsibilities in both companies effective January 1, 2012 and for the term of the PBR it is now appropriate and relevant to apply.
>
> FEI and FBC have also used the Massachusetts Formula to allocate costs in previously approved revenue requirement applications. Corporate costs have been allocated from FHI to the FEU using the Massachusetts Formula for many years. Board of Directors costs have also been allocated from FHI to FEI and FBC utilizing the Massachusetts Formula since 2010. Therefore applying this same cost allocation methodology to Executive Management costs allows for consistency and familiarity."

133. FBC's and FEI's requests to apply the Massachusetts formula to fully loaded Executive labour costs beginning in 2014 is not intended to vary the amount allocated significantly from the time estimate methodology.[161]

134. The difference going forward into the PBR period is also not expected to result in materially different overall O&M expense. However any differences that do arise from variances in the Massachusetts formula percentages or variances in the fully loaded Executive

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[160] Exhibit B-24, BCUC IR 2.329.4.

[161] Exhibit B-24, BCUC IR 2.329.5.

labour costs, will be managed by FBC and FEI throughout the PBR period and rates will be set according to the O&M formula.[162]

135. In short, with all the executives for FBC and FEI now having joint responsibilities in both companies it is appropriate to use the well-established Massachusetts formula to allocate executive cross charges between FEI and FBC.

(g) Capitalized Overhead

136. FEI has proposed that the overhead capitalization rate remain at 14% of O&M, the same as approved for the 2010-2011 and 2012-2013 periods.[163] In response to Directive 29 from the 2012-2013 RRA Decision, FEI filed a study by KPMG reviewing the overheads capitalized rate using relevant accounting standards (the "2013 KPMG Study"). The need for a review based on relevant accounting standards arose because the previous study relied upon by FEI (the 2010/2011 KPMG Overheads Capitalized Study) was conducted in anticipation of adoption of IFRS and yielded an estimated rate of 8% that was almost entirely due to assuming IFRS accounting guidance. Under IFRS, unless costs are directly attributable to capital projects, the costs cannot be capitalized and therefore there had to be a direct causal linkage between the cost incurred and the capital project. The 2013 KPMG Study was prepared assuming US GAAP, Federal Energy Regulatory Commission and BCUC accounting guidance that all allow for the capitalization of overheads that is indirectly attributable to capital work and supports a higher overhead capitalized rate than that determined under IFRS.[164]

137. While the results of the 2013 KPMG Study are lower than the existing rate, FEI considers the results to generally confirm that FEI's existing 14% rate is in a reasonable range. The KPMG studies provide two estimates of a reasonable overhead capitalization rate, with a survey-based approach suggesting a 12% rate and a mathematical-based approach yielding an 11% rate. The survey-based approach is subjective in nature and KPMG states that the rate "is

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[162] Exhibit B-24, BCUC IR 2.329.7.

[163] Application, pp. 286 to 288.

[164] Application, p. 286-288; Exhibit B-8, CEC IR 1.78.2.

estimated to be approximately 12 percent", suggesting that the rate is indicative in nature, but not definitive.[165]

138. Other factors favour retaining the existing 14% capitalized overhead, as follows:

- FEI's capitalization rate of 14% is within a range of other Canadian and U.S. utilities surveyed by the Company, as included in Appendix A of the 2013 KPMG Study.[166]

- There has been no relevant material change in utility operations that would warrant a change to the overhead capitalization rate.[167]

- FEI expects capital spending to increase over the PBR Period and the lower overhead capitalization rate would be counter to the trend.[168]

- Decreasing the estimated rate to 12% would have the negative effect of increasing customer delivery rates by about 0.8%.[169]

139. For these reasons, FEI submits that it is appropriate to retain its existing overhead capitalization rate of 14%.

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165 Application, p. 288; Exhibit B-1-1, Appendix F3, 2013 KMPG Study.

166 Application, p. 289 and Exhibit B-1-1, Appendix F3, 2013 KPMG Study, Appendix A.

167 Application, p. 289.

168 Illustrated in the Application, Section D.3.7, page 289, Table D3-9.

169 The impact on delivery rates due to a change in the overhead capitalization rate is approximately 0.4 percent for every 1.0 percent change in the other direction in the overhead capitalization rate. For example, reducing the overhead capitalization rate from 14 percent to 12 percent would increase customer delivery rates by approximately 0.8 percent and a reduction of the overhead capitalization rate from 14 percent to 11 percent would increase customer delivery rates by approximately 1.2 percent. (Exhibit B-11, BCUC IR 1.168.3).

B. Deferrals

(a) MCRA, RSAM and SCP Mitigation Revenues

140. FEI is applying to reduce the amortization period from three to two years for its MCRA and RSAM accounts, as well as for the interest on those accounts. This is due to the US GAAP requirement that "alternative revenue programs" be amortized within 24 months.[170]

(b) Pension and OPEB Variance

141. FEI is requesting approval to extend the amortization period of the Pension and OPEB Variance account from the currently approved three year period to the Expected Average Remaining Service Life ("EARSL") of the benefit plans.[171] Extending the amortization period to the EARSL more appropriately allocates the costs over the future period to which they are applicable. The EARSL is an average of the employees' average expected time to retirement and would represent the period of time FEI would expect the employee, on average, to be an employee.

142. The longer amortization period requested will also allow for smoother rates for customers in future years.[172] Since the existing three-year amortization period was set, there has been a large increase in the pension expense due to low interest rates, which lowers the discounting of the liability which, in turn, results in higher pension and OPEB expenses each year. The discount rate is set in reference to Canadian Corporate AA bonds and the rate used is beyond the control of FEI. As a result, the annual variances recorded in the deferral account have been significant.[173] The change to the amortization period as requested will allow for smoother rates for customers in future years.

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[170] Application, pp. 293-294; Exhibit B-24, BCUC IR 2.331.1.
[171] Application, p. 294.
[172] Exhibit B-11, BCUC IR 1.173.1.
[173] Exhibit B-11, BCUC IR 1.173.2.1.

143. With respect to why this is a rate-base deferral account, FEI's preference is to hold deferral accounts as part of rate base to keep as much consistency as possible in the treatment of deferrals. FEI normally only requests non-rate base deferrals due to timing issues or to stream costs to a particular customer group. In this case, neither of these conditions exist. As the deferral account should attract a return based on the weighted average cost of capital ("WACC") regardless of whether it is in rate base, it makes no difference to customers if this is a rate base or non-rate base account.[174]

144. The amounts recorded in this deferral account are both capital and non-capital in nature, as some amounts would normally be capitalized as part of the labour loadings for those employees that perform capital work, and some would be expensed for those employees that do not. The nature of the amounts (capital or non-capital) should not impact the type of return the deferral account should earn. FEI explained as follows:[175]

> "…as stated in other recent applications of the FortisBC Utilities, FEI believes that the nature of the amounts (capital or non-capital) should not impact the type of return the deferral account should earn. This is because the moment an item is placed into a deferral account for future recovery or refund, it ceases to become a "non-capital" item. It has now become akin to a capital item in that costs are being incurred in one period and not being recovered from ratepayers until a future period. In fact, even non-capital (or operating items) that are expensed and recovered within the same test year receive a rate base return through the working capital component to the extent there is a time lag in their recovery during the year.
>
> It is not relevant whether an item was originally of a capital nature or not, because the nature of the expenditure has been changed by recording it into the deferral account. Allowing deferrals to attract a rate base rate of return recovers the costs associated with the timing difference when there is an outlay of funds and when those costs are recovered from ratepayers. A rate base rate of return is the only logical and consistent approach to be applied; providing consistency between those deferrals that are in rate base and those that are held outside of rate base".

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[174] Exhibit B-11, BCUC IR 1.173.6. Also see Exhibit B-1-1, Appendix F5, Non-Rate Base Deferrals.

[175] Exhibit B-11, BCUC IR 1.173.7.

145. FEI submits that its proposed change to the amortization of the Pension and OPEB Variance account and existing treatment of these cost are just and reasonable and respectfully request that it be approved.

(c) Customer Service Variance Deferral

146. FEI is seeking approval to amortize the forecast 2013 positive balance in the Customer Service Variance Account through delivery rates over five years beginning in 2014. It is important to smooth the rate impacts over the term of the PBR in order to prevent unnecessary fluctuations in rates and provide rate stability for customers. FEI adopts this approach for many of its deferral accounts, regardless of whether the funds are returned to customers (as is the case with this account) or recovered from customers. It is also appropriate to amortize the Customer Service Variance Account over five years to better align with the amortization period of the existing 2010/2011 Customer Service O&M and Cost of Service deferral. The annual costs to customers for the amortization of the 2010/2011 Customer Service O&M and Cost of Service deferral would be almost fully offset by the forecasted amortization credit for the Customer Service Variance Account.[176] For these reasons, FEI submits that its proposed treatment is just and reasonable and respectfully requests that it be approved.

(d) General Cost of Capital ("GCOC") Application

147. FEI is seeking approval to amortize a rate base deferral account over two years related to the costs of the GCOC Stage 1 proceeding, less the amounts recovered from other affected utilities. The deferral account will not contain costs related to the Stage 2 proceeding.[177] FEI has included this deferral account in rate base as this treatment is consistent with past practice for deferral accounts that hold costs related to regulatory proceedings, and in particular costs related to cost of capital proceedings. Whether a deferral account is in rate base or not, it is subject to a rate base rate of return, and therefore there is no difference to

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[176] Exhibit B-11, BCUC IR 1.174.1.

[177] Exhibit B-11, BCUC IR 1.175.2.

customers between the two treatments.[178] The proposed GCOC Application deferral account is consistent with the past practice of the Commission and FEI respectfully requests that it be approved.

(e) CNG and LNG Recoveries

148. The CNG and LNG Recoveries Deferral Account captures the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand amounts embedded in the 2012 and 2013 revenue requirements. FEI initially applied to discontinue this account but, in the February 2014 Evidentiary Update, FEI withdrew this request due to Special Direction No. 5 which has directed that CNG and LNG service be part of the natural gas class of service. As it is now appropriate for the excess recoveries in the account to be returned to the natural gas class of service customers, FEI is applying to continue the CNG and LNG Recoveries deferral account.[179]

(f) Residual Delivery Rate Riders and Management of Deferral Accounts

149. The Residual Rate Rider account was created as part of the 2012-2013 RRA to transfer into rate base three residual non-rate base deferral accounts that originally used riders to recover the balances in the accounts. Instead of using rate riders, the remaining net balances in these accounts are now amortized. FEI is seeking approval to combine three more residual deferral accounts, each of which also used riders to recover the balances in the accounts, into the Residual Rate Riders account.[180] This approach reduces the number of deferral accounts and rate riders, and continues the precedent of combining residual rider deferrals for ease of returning or recovering the balance from customers.[181]

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[178] Exhibit B-11, BCUC IR 1.175.1.

[179] Exhibit B-1-5, p. 4.

[180] Exhibit B-11, BCUC IR 1.177.2.

[181] Exhibit B-11, BCUC IR 1.177.2.

150. An IR requested FEI's views on whether the Commission should create a materiality threshold that would require smaller balances in deferral accounts to be amortized over one year.[182] This suggested treatment would not be appropriate. FEI has requested and received approval for a specific amortization period for each individual deferral account based on a consideration of the specific circumstances of that deferral. Adopting a one year amortization period based simply on the amount in the account in any given year would ignore the reasons for the initial approval of the amortization period. Further, FEI will usually seek amortization periods for deferral accounts to keep customer rates manageable, depending on the forecasted activity in each account. Amortizing amounts under a million dollars in one year could create unnecessary rate fluctuations and could result in material rate impacts to FEI customers. Using a materiality threshold as suggested in the IR could also result in changing the amortization period from year to year, which has the potential to be administratively burdensome and confusing. FEI therefore submits that deferral accounts should continue to be amortized in accordance with amortization periods that are appropriate for that account as approved by the Commission.

151. Information requests also requested FEI's views on whether the Commission should eliminate deferral accounts for recurring non-controllable amounts and use the average amortization for the past 5 years to determine the costs recoverable under the PBR.[183] This is inappropriate for a number of reasons. First, the amortization only returns to or recovers from customers variances between the amounts already embedded in revenue requirements and the actual amounts incurred. To simply include the average amortization of the deferral as the revenue requirement cost is incorrect as the forecast amount of the expense covered by the deferral account for each year would not be recovered, which would be unfair. There is also an issue of fairness for both the customer and the utility. One of the reasons for establishing the deferral accounts is the recognition that these costs are beyond the control of the utility and therefore difficult to forecast accurately. (These accounts include, for example, pension,

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[182] Exhibit B-24, BCUC IR 2.334.1(a).

[183] Exhibit B-24, BCUC IR 2.334.1(b).

property tax and insurance variances.) Eliminating these deferral accounts would make variances from forecast a windfall to either the shareholder or customers. In addition, if the approach proposed in the question was adopted, more regulatory process would be required and there would be more controversy related to establishing the appropriate forecast level of the expense category for each deferral account. Gains made in streamlining the management of deferral accounts would be lost to the additional regulatory process required to set forecast expense amounts and review the additional items that may now be viewed as potential exogenous factors. For these reasons, FEI submits that the suggested use of an average amortization amount is not just and reasonable.

PART SIX: BCUC UNIFORM SYSTEM OF ACCOUNTS

152. Directive 63 of Order G-44-12 issued on April 12, 2012 directed the FEU to investigate the cost of fully converting to the BCUC USoA and to file a proposed plan for conversion. On October 12, 2012 FEU submitted a compliance filing that consisted of a report on the USoA ("FEI's USofA Report"), to address the underlying concerns of the Directive, and a proposal for an alternate approach, which included an update to the O&M Code of Accounts to respond to the concerns of the Commission (the "New Code of Accounts"). In its letter in response to the FEU's Compliance Filing, the Commission wrote:[184]

> "The Commission has reviewed FEU's proposed alternate approach and accepts it for the next Revenue Requirements Application (RRA) only. In the next RRA the Commission will assess whether FEU is required to either comply with Directive 63, continue with the alternate approach for further RRA's, or implement some other approach as the Commission finds appropriate at that time."

153. Accordingly, FEI has used its New Code of Accounts in this Application. Information requests explored FEI's approach of adopting the New Code of Accounts and alternatives.

154. FEI submits that use of its New Code of Accounts is preferable to adopting the USoA. As stated in FEI's USoA Report,[185] the existing New Code of Accounts approach provides more meaningful and comparable information than the BCUC USoA, which has not been substantially updated since 1961, and at no additional cost to customers.[186] This conclusion is based on the following:

(a) Other than O&M accounts, the FEU are already meeting existing BCUC USoA requirements;

[184] Exhibit A2-14, Commission letter dated December 3, 2012 - Compliance Filing - FortisBC Energy Utilities - BCUC Uniform System of Accounts Report.

[185] Included in Exhibit A2-13.

[186] Exhibit B-24, BCUC IR 2.308.1.

(b) Full implementation of the BCUC USoA would result in additional costs being borne by customers with no guaranteed improvement in understanding or comparability;

(c) For O&M accounts, flexibility is required amongst the utilities in BC to determine a method that meets the objectives of comparability, transparency and understanding of results over time;

(d) The FEU already have a fully reviewed and agreed-upon New Code of Accounts that meets those objectives; and

(e) The FEU have reviewed the BCUC USoA and other uniform systems of accounts for O&M and have concluded that none of the ones reviewed would provide a measurable improvement over the New Code of Accounts.

155. FEI has also considered the alternative of using the New Code of Accounts only for O&M with a "mapping relationship" to the BCUC USoA and the alternative of using both the New Code of Accounts and the BCUC USoA for O&M, for management and regulatory purposes, respectively. However, these options have no advantages because there is no evidence that more information would be provided by using the BCUC USofA.[187] All alternatives involving use of the BCUC USofA would provide no incremental value and will tie up FEI's resources in a project, potentially incur incremental external costs, and require a reconciliation process each year.[188]

156. Some of the information requests suggested that adopting a different USoA would enable FEI to provide more accurate information or resolve comparability problems.[189]

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[187] Exhibit B-24, BCUC IR 2.308.1. For a detailed discussion of the "mapping" option, see Exhibit B-24, BCUC IR 2.308.9.

[188] Exhibit B-24, BCUC IR 2.309.1.

[189] Exhibit B-24, BCUC IR 2.309.1.

However, adoption of the BCUC USoA would not result in information that is more comparable than it currently is. As FEI explained:[190]

> "A different method of grouping costs does not change the fact that accounting policies have changed to required capitalization differences, or that data that was previously captured at a higher level cannot be retroactively split to a lower level without considerable estimation which makes the data unreliable, or that there have been changes in the environment that drive costs and make O&M costs from 2007 not comparable to O&M costs from 2014."

Furthermore, FEI would not be able to provide accurate responses to questions on the BCUC USoA accounts since much of the data for the accounts would have to be created through a judgement-based allocation process.[191] Using the New Code of Accounts, FEI is able to provide historical information using current business descriptions which are not present in the BCUC USoA.[192] No interveners have raised a concern with the availability of information or the use of the New Code of Accounts.[193]

157. While adoption of a Uniform System of Accounts has occurred in Alberta, in that case the Energy Utilities Board ("EUB") concluded that the costs involved would add value based on the evidence in that process. As FEI has explained, there are differences between the regulatory environments in Alberta and BC that make the value proposition in BC significantly less. For example, the BCUC USoA will not improve the ability to compare financial information from year to year, which was one of the main benefits in the EUB's case.[194] Incurring costs without a clear understanding of what benefits would be obtained would not be in ratepayers' interests.[195]

158. For these reasons, FEI submits that use of the New Code of Accounts is the preferable alternative and that FEI should not be required to use the BCUC USoA for O&M.

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[190] Exhibit B-24, BCUC IR 2.309.1.

[191] Exhibit B-24, BCUC IR 2.309.1

[192] Exhibit B-24, BCUC IR 2.311.1.

[193] Exhibit B-24, BCUC IR 2.308.5.2.

[194] Exhibit B-24, BCUC IR 2.308.5.2.

[195] Exhibit B-24, BCUC IR 2.308.5.2.

PART SEVEN: THERMAL ENERGY SERVICES

A. Introduction

159. FAES is a separate legal entity from FEI that provides TES to customers.[196]

160. Historically, FAES's projects have been carried out by FEI employees who direct charged their time to the TESDA. As of January 1, 2014, all employees who are dedicated solely to the FAES business were transferred out of FEI to an affiliate company.[197] To the extent that remaining FEI employees have involvement with FAES activities, they charge their time directly to the TESDA or FAES via timesheets. As described in this section, FEI's time tracking process ensures that all costs attributable to FAES operations have been appropriately charged.

161. FEI also provides FAES with corporate and administrative services which are recovered by FEI through an annual overhead allocation to the TESDA. This section addresses FEI's proposed approach to the overhead allocation to FAES in light of an ongoing regulatory process that may have an impact on the amount of the allocation. FEI's proposal will keep FEI's customers whole, while allowing other regulatory processes that bear on this issue to unfold in due course.

162. This section also responds to a number of other issues raised by the Commission and the Coalition for Open Competition ("COC") with respect to the relationship between FAES and FEI.

B. Direct Charges to the TESDA

163. The FEI staff who directly work on FAES projects either charge time through timesheets to the TESDA, or to capital of a specific project in FAES, or to operations and

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[196] Exhibit B-11, BCUC 1.203.2.

[197] Exhibit B-24, BCUC IR 2.359.1.

maintenance within FAES for those projects that are in-service in FAES. As a result, these costs are not reflected in this Application or, for clarity, in the 2013 Base O&M or Base Capital.[198]

164. Direct charges are recorded via timesheets, with the cost calculated at fully loaded labour cost.[199] Employees are assigned labour rates based on the annualized cost of labour and benefits divided by annualized chargeable hours. Annual chargeable hours are determined by taking total work hours in a year (based on a five day work week of 37.5 hours) and deducting hours related to statutory holidays, annual vacation, paid days off, and an estimate of employee sick time.[200]

165. FEI's time sheet based allocation approach has been used successfully for a number of years. The system is designed to capture the necessary input from employees who are best able to assess where their time has been spent. FEI's existing time sheet approach and the importance of costing information is well understood by its employees.[201]

166. FEI submits that its cost allocation process based on time sheets is appropriate and well established and leads to accurate and representative costs for services provided to different projects and services. FEI submits that this approach will continue to work in the future to ensure appropriate cost allocations between the different projects/services and entities.

C. FEI's Approach to Overhead Allocation

167. FEI expects to continue to provide corporate and shared services to FAES during the PBR Period and therefore FEI will allocate an appropriate amount to the TESDA for these services.[202] The background to understanding FEI's approach to allocating overhead costs to

[198] Exhibit B-24, BCUC 2.313.2.

[199] Exhibit B-24, BCUC 2.313.7.

[200] Exhibit B-24, BCUC IR 2.313.8.

[201] Exhibit B-24, BCUC IR 2.313.7.

[202] See Exhibit B-24, BCUC 2.313.1 for a description of the items included in this allocation.

the TESDA during the PBR Period is the Commission's Report on its Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (the "AES Inquiry Report").[203]

168. In the AES Inquiry Report, the Panel directed the FEU to undertake a collaborative process to establish a code of conduct and transfer pricing policy ("CoC/TPP") governing the interactions between affiliated regulated business.[204] The results of the CoC/TPP Review which is currently underway may have an impact on the amount of FEI's overhead allocation to FAES. As a result, FAES plans on filing an updated TESDA report once the CoC/TPP Review is complete.[205] This means that FEI cannot say, with any certainty, what the final TESDA allocations will be during the PBR Period. As explained below, FEI's proposal addresses this uncertainty in a way that ensures that both FEI and FAES customers are kept whole.[206]

169. The amount of O&M to be allocated to FAES in 2013 has already been decided by the Commission in Order G-44-12 at $854 thousand.[207] FEI's proposal is to use this amount for the 2013 Base Year O&M, and to escalate this amount by the O&M formula for the PBR Period. As a result, the following will be credited to FEI's O&M during the PBR Period:[208]

2014 - $869,000
2015 - $886,000
2016 - $902,000
2017 - $919,000
2018 - $936,000

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[203] The AES Inquiry Report, dated December 2012, is available online at: http://www.bcuc.com/Documents/Arguments/2012/DOC_33032_12-27-2012-G-201-12_FEI-AES-Inquiry-Report_WEB.pdf.

[204] AES Inquiry Report, p. 27.

[205] Exhibit B-11, BCUC IR 1.172.5.

[206] In a recent discussion with Commission staff, it was agreed that FEI would target Q1/Q2 of 2014 for filing a proposed Transfer Pricing Policy and Code of Conduct update for review and approval by the Commission (the CoC/TPP Review): Exhibit B-11, BCUC IR 1.172.5.

[207] Exhibit B-24, BCUC IR 2.356.1.

[208] Exhibit B-24, BCUC IR 2.356.1.

170. Since FEI cannot predict with certainty the overhead allocations that will result from the CoC/TPP Review, FEI's proposal is to establish the TESDA Overhead Allocation Variance Account. This account will capture the difference between the formula-determined amount of overheads recovered by FEI from thermal energy customers (as described in the preceding paragraph) and the final allocation, including any adjustments that will result from the CoC/TPP Review. FEI proposes to address the disposition of any amounts recorded in this deferral account in its first Annual Review to be held in 2014.[209]

171. FEI's proposed approach will keep both FEI's and FAES' customers whole. If the allocation to the TESDA is determined to be greater than the formula-calculated amounts, the amount recorded in the deferral account would be a credit that would be returned to FEI customers through amortization. If the amount is less than the formula-calculated amounts, the amount recorded in the deferral account would be a debit recovered through amortization.[210]

172. FEI's proposal is a fair approach to dealing with the uncertainty created by the CoC/TPP Review. Without this deferral account, it will not be possible for the amount recovered from FAES to reflect the results of the CoC/TPP that FEI and other stakeholders are currently undertaking to review; in other words, FEI customers would take the risk that the amount that should be charged under the approved CoC/TPP ends up being greater, while FAES customers would be at risk if the amount turns out to be lower than the allocated amounts.[211]

173. FEI respectfully requests that its approach to the allocation of overhead to the TESDA, and the TESDA Overhead Allocation Variance Account, be approved.

[209] Application, Section D4.1.2, pp. 292-293.

[210] Exhibit B-24, BCUC IR 2.356.1.

[211] Exhibit B-24, BCUC IR 2.356.3.

D. Issues Raised Regarding FAES

174. Both the COC and the Commission asked a number of questions regarding the relationship between FEI and FAES and a number of specific transfer pricing and code of conduct issues. Many of these issues will be dealt with in the upcoming CoC/TPP Review proceeding, and should not be addressed in this proceeding. However, since the issues were raised in the information request process, and in the interest of being helpful, the following describes the issues raised, a summary of FEI's response, and a reference to FEI's detailed responses on these issues.

(a) The Commission asked about the extent to which there is value to FAES to have FEI provide information about TES products to its customers, which is not something that is available to other competitors of FAES. As noted in its response, FEI staff does not direct any customers to contact FAES; rather, FEI staff make the customers aware of their energy solutions alternatives, which include mentioning TES and FAES. FEI submits that there is no unfair competitive advantage or "value" that can or should be ascribed to this information and customer service approach. FEI staff are not selling the services of FAES, but rather informing their own customers of their options in the hope of retaining as much natural gas load as possible.[212]

(b) The Commission asked about the appropriateness of the use of a single website that encompasses all the FortisBC regulated services, and therefore includes gas, electric and TES. As FEI noted in its responses to these questions, in the AES Inquiry Report the Commission determined that "the use of the FortisBC brand name in the AES and New Initiatives market space is an acceptable practice. Care should be taken to distinguish between the services offered by the traditional natural gas utility and services offered by Affiliated Regulated or Non-Regulated Business." FortisBC has complied with this recommended practice,

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[212] Exhibit B-24, BCUC 2.358.2 to 2.358.7.

and in any event, the FortisBC name and brand is an intangible asset owned by Fortis Inc. and not by FEI. As such, there is no assigned value to FEI which would support any basis for seeking recovery from FAES for the use of the corporate name FortisBC.[213]

(c) In response to questions from COC, FEI has confirmed its intention to have Price Waterhouse Coopers ("PWC") review all projects involving a customer who applies for EEC funds that have a third party thermal energy service component, regardless of supplier. FEI also confirmed that FEI's EEC staff are sensitive to the need in the marketplace to maintain an even playing field with respect to the disposition of EEC funds.[214] See also FEI's submissions in Part 8 below on the PWC proposal.

(d) FEI responded to a number of questions from COC regarding a FortisBC advertisement for the 2012 EFMA conference that referenced that FortisBC delivers energy services "from natural gas, piped propane and electricity to district energy and geoexchange". In response to the questions, FEI explained why this kind of advertisement is appropriate and consistent with the AES Inquiry Report (which the ad predated). FEI also confirmed that a portion of the costs of the sponsorship of this conference and advertisement were allocated to the TESDA.[215]

(e) COC asked a number of questions about the "www.fortisbc.com" website, and in particular the fact that it references TES. In response, FEI explained that the FortisBC website provides a single point of access for all FortisBC's regulated services, thus facilitating a positive interaction for its customers. The website segregates between gas, electric and TES offerings so that, while the initial landing page is a common site, it allows for the customer to select the type of

[213] Exhibit B-24, BCUC 2.361.1 to 2.361.4.

[214] Exhibit B-13, COC IRs 1.2.1 to 1.2; Exhibit B-19, COC IRs 2.9.1 to 2.9.11.

[215] Exhibit B-13, COC IRs 1.5.1 to 1.5.6.4.

service(s) they are interested in. This approach is consistent with the Commission's Determination in regards to the use of the FortisBC brand name as outlined on pages 40-41 of the AES Inquiry Report. FEI further explained that it is currently in the process of updating its website in order to recognize that FAES is the entity marketing and providing TES to customers. Finally, FEI confirmed that FAES contributes to the costs of the FortisBC website through the overhead allocation to the TESDA.[216]

175. FEI will provide further submissions on these and related issues in its Reply Submission to the extent that they are raised by interveners and relevant to this proceeding.

[216] Exhibit B-13, COC IRs 1.6.1 to 1.6.10.

PART EIGHT: EEC EXPENDITURES

A. Introduction

176. 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 as a result of the FEU's 2008 application for acceptance of 2008, 2009 and 2010 EEC expenditures. The FEU continued to build on that portfolio in its 2010-2011 and 2012-2013 revenue requirement applications and approvals granted by the Commission. As has been discussed in previous proceedings, the initial years of the FEU's efforts have been characterized by a significant ramping up of expenditures and resources to deliver an expanding EEC portfolio, coupled with challenges with the low cost of natural gas and the downturn in the economy. The current five-year 2014-2018 EEC Plan marks a milestone in the FEU's EEC portfolio as it transitions from relatively rapid expansion to a more stable and sustained delivery of existing programs.

177. While challenges such as the low cost of natural gas remain, the FEU now have a more complete complement of EEC staff and experience with their EEC programs such that the EEC portfolio is expected to be more stable in the coming years. In addition, the regulatory framework surrounding the FEU's EEC expenditures has been modified and fine-tuned by the Commission over successive proceedings as both the FEU and the Commission gain experience in this area. Notably, the FEU have developed, and the Commission approved, appropriate deferral account mechanisms to ensure that customers are not negatively impacted by the uncertainty in actual vs. approved expenditures, which vary depending on the extent to which customers decide to take up EEC measures.

178. In this Application the FEU's 2014-2018 EEC Plan consists mostly of existing previously approved programs. The FEU are seeking to sustain the existing level of approved EEC expenditures over a five-year period and to retain the EEC framework that has been

recently refined and approved by the Commission, with a limited number of new programs and adjustments. Acceptance of the 2014-2018 EEC expenditures as being in the public interest will provide a stable platform for the FEU's portfolio of EEC programs to gain more traction in the market and, ultimately transform the market.

179. The FEU's proposed EEC expenditure schedules are set out in Appendix I of the Application, with the FEU's 2014-2018 EEC Plan Included as Attachment I-1.[217] Pursuant to section 44.2(3) and (4) of the UCA, the Commission must accept the expenditure schedule if it considers the schedule to be in the public interest, or it may accept a part of the schedule.[218] In considering whether a demand-side measure expenditure schedule put forward by a non-crown public utility is in the public interest, the Commission must consider four criteria as set out in section 44.2(5). These criteria are follows:

- *The applicable of British Columbia's energy objectives*. Consistent with prior Commission determinations, FEI's EEC expenditures are consistent with British Columbia's energy objectives, including by conserving energy, reducing greenhouse gas (GHG) emissions, and encourage economic development and the creation and retention of jobs.[219]

- *The most recent long-term resource plan filed by the public utility under section 44.1, if any.* FEI's EEC expenditures are consistent with the FEU's 2010 LTRP.[220] The long term EEC analysis contained in the most recently filed LTRP builds off of the results of the 2014-2018 EEC Plan and is therefore in alignment with the EEC expenditures in this Application.[221]

[217] Exhibit B-1-1.

[218] The legal framework governing the acceptance of EEC expenditures under the UCA has been described by the FEU in Section 2 of Attachment I of the Application.

[219] Application, Appendix I, pp. 3-5.

[220] Application, Appendix I, pp. 3-5.

[221] Exhibit B-24, BCUC IR 2.368.2.

- *Whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any*. The FEU's 2014-2018 EEC Plan is cost-effective on a portfolio basis under the Total resource cost ("TRC") and modified TRC ("mTRC") tests prescribed in the *Demand-Side Measures Regulation* ("DSM Regulation").[222] This approach to cost-effectiveness has been consistently used and approved by the Commission.[223]

- *The interests of persons in British Columbia who receive or may receive service from the public utility*. The proposed EEC expenditures 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 consumers that avail themselves of EEC measures will reduce their natural gas consumption and their natural gas bills.[224]

180. The FEU therefore submit that the expenditures are in the public interest and should be accepted pursuant to section 44.2 of the UCA.

181. The following sections will address the material issues raised in information requests during the proceeding.

B. The Proposed Level of Expenditures is in the Public Interest

182. The 2014-2018 EEC Plan in Appendix I, Attachment I-1 of the Application describes the FEU's EEC funding request over the 2014 to 2018 period. FEI has requested approval of an EEC funding envelope of $34.4 million in 2014 and increasing up to $39.0 million in 2018.[225]

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222 B.C. Reg. 326/2008, as amended.

223 Order G-36-09; Order G-141-09, Appendix A, Section 12(e); and the 2012-2013 RRA Decision, Order G-44-12.

224 Exhibit B-1-1, Appendix I, p. 7.

225 Exhibit B-1-1, Table I-4 of Appendix I; Attachment I-1 provides a summary of expenditures, including inflation; Exhibit B-9, COPE IR 1.8.5; Exhibit B-24, BCUC IR 2.369.4.

(a) Use of 2012-2013 Expenditure Levels

183. Concerns with respect to the FEU's proposed level of expenditures centred on how the FEU's proposed level of funding was derived and the apparent concern that the FEU's proposal to continue with 2012-2013 Approved levels of expenditures was constraining the programs that the FEU have proposed. As explained below, although the FEU have taken the Commission's 2012-2013 Approved levels as a guide for overall expenditure levels, the FEU's proposed level of expenditures is sufficient to pursue all cost-effective EEC programs in the FEU's Conservation Potential Review ("CPR").

184. In determining what the overall funding level should be for the 2014-2018 period, the FEU have used the 2012-2013 Approved level of expenditures as a guide. In the 2012-2013 RRA proceeding, the FEU requested a large increase in EEC spending, but the request was reduced by the 2012-13 RRA Decision.[226] Accordingly, in this proceeding the FEU have taken the Commission's 2012-2013 RRA Decision as representative of the level of EEC expenditures and rate impacts that are appropriate for the programs it is proposing. Because most of the programs in the 2014-2018 EEC Plan are the same programs that were approved for 2012-2013,[227] it is reasonable to consider the Commission's 2012-2013 Approved funding levels as those indicative of the levels that are appropriate to maintain, and the level of rate impact that has been acceptable to the Commission.

185. The FEU also consulted with members of the Energy Efficiency and Conservation Advisory Group ("EECAG") and there was no indication that any major "course corrections" were necessary.[228] This supports the continuation of existing levels of expenditures rather than a dramatic shift.

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226 Exhibit B-9, COPE IR 1.8.2.

227 Exhibit B-1-1, Application, Appendix I, Table I-5, pp. 18-19. There are 6 new programs, each of which is in an existing program area.

228 Exhibit B-11, BCUC IR 1.224.1.

186. The level of proposed funding levels are also supported by the detailed program budgets presented in the 2014-2018 EEC Plan. These budgets were the result of a collaborative working effort between the FEU EEC program personnel and ICF Marbek staff.[229] The budget creation includes a reasonable estimation of the number of participants that could be achieved.[230]

187. The proposed spending level has not constrained the implementation of any EEC programs. If, for example, the FEU were to increase the funding limit by 10 or 50%, it would not develop or implement any new programs or expand existing programs.[231] Furthermore, there are no cost-effective EEC programs identified in the CPR that the FEU are not proposing. The only measures in the Residential program area that appeared to be cost-effective in the CPR that were not included in the 2014-2018 Plan were Programmable Thermostats, Solar Pool Heaters and Energy Star® Clothes Washers:[232]

- Although the programmable thermostat ("P-Stat") program could be cost effective in BC based on certain assumptions, the FEU were concerned about whether the energy savings claims could be validated. For example, in 2009, ENERGY STAR removed its label from programmable thermostats due to industry concerns about energy savings validation. In addition, the market is largely transformed with 61% of FEU customers having already installed this measure. The FEU will continue to conduct research on the validation of energy savings claims, and once satisfied that the claims are credible, FEU will assess the opportunity to include programmable thermostat technologies as a measure within approved program funding envelopes.[233]

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[229] Exhibit B-11, BCUC IR 1.224.1.

[230] Exhibit B-1-1, Appendix I-1, as amended by Exhibit B-43. Exhibit B-24, BCUC IR 2.373.4.

[231] Exhibit B-11, BCUC IR 1.224.1.1.

[232] Exhibit B-24, BCUC IR 2.364.1.

[233] Exhibit B-24, BCUC IR 2.373.3.

- A program for Solar Pool Heaters has too high a free rider rate to justify the provision of an incentive.[234]

- As noted on page 11 of the 2014-2018 EEC Plan, "FEU will limit investment in Energy Star® washers to short term promotions since the washer market has matured such that there is reduced opportunity to capture natural gas savings". Should it appear that such a promotion would be cost-effective, funding for such activity would come from the envelope of funding proposed for water heating measures."[235]

All measures in the Commercial and Industrial sectors that do not have prescriptive programs associated with them in the 2014-2018 EEC Plan would be included in the "custom" incentive options.[236] (See the Customized Equipment Upgrade Program in the Commercial Program Area and the Industrial Optimization Program in the Industrial Program Area.[237])

188. While increasing expenditures on programs *may* increase participation,[238] based on actual experience with the FEU's EEC programs, the expenditure levels that the FEU are seeking are not expected to constrain participation. While the FEU have been expanding its EEC programs and spending since 2009, it does not expect the spending growth rate experienced in the last four years to continue.[239] The FEU have requested approval of an EEC funding envelope of $34.4 million in 2014 and increasing up to $39.0 million in 2018, which is an average increase of more than 3% per year for that four-year interval. If the full amount of the spending envelope of $34.4 million is spent for 2014, this will reflect an increase of 66% from the 2012 EEC spending of $20.7 million.[240] Thus, while the EEC spending growth forecast during the PBR

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234 Exhibit B-24, BCUC IR 2.364.1.

235 Exhibit B-24, BCUC IR 2.364.1.

236 Exhibit B-24, BCUC IR 2.364.1.

237 Exhibit B-1-1, Application, Appendix I-1, pp. 48 and 64, respectively.

238 Exhibit B-11, BCUC IR 1.226.1.

239 Exhibit B-9, COPE IR 1.8.5.

240 Exhibit B-9, COPE IR 1.8.5.

period may be considered modest, the annual spending amounts are at high levels compared to the last four years of program growth.[241]

189. Furthermore, the FEU's proposed expenditure schedules do not preclude the development of more programs or requests for further expenditures. The FEU have asked for approval to initiate additional programs within approved program areas during the term of the PBR Period. Also, should it appear over the test period that existing cost effective programs warrant expansion or that more cost-effective natural gas EEC activity could be deployed in British Columbia, and if customer rate impacts were considered to be acceptable by the FEU and by the EECAG, the FEU could re-apply to the Commission for additional EEC funding.[242] At this time, however, the FEU have no programs that they could add to the 2014-2018 EEC Plan currently before the Commission.

(b) Industry Comparisons

190. The BCUC IR 2.369 series explored whether the FEU's level of proposed EEC expenditures was in line with industry standards. In response to these IRs, FEU used the information available from CGA member utilities (including ATCO, Enbridge, SaskPower, Gas Metro, Manitoba Hydro and Union Gas) to calculate demand-side management ("DSM") expenditures as a percentage of distribution revenues. The results show that the FEU's 3% of distribution revenue is comparable to the average of 2.71%. However, FEI expressed caution with respect to the use of this data due to the challenges that the CGA members had in finding comparable data amongst the utilities.[243]

191. The BCSEA Intervener Evidence is generally supportive of the FEU's program and states that the FEU's level of expenditures was "not unreasonable" and that its costs to achieve planned savings are in line with industry experience. While BCSEA states that "the FEU's annual

[241] Exhibit B-9, COPE IR 1.8.5.

[242] Exhibit B-11, BCUC IR 1.224.1.1.

[243] Exhibit B-24, BCUC IRs 2.369.1 and 2.369.1.1.

gas savings plans are behind industry leaders," it notes that the FEU's depth of savings is "in the middle of the pack for gas DSM administrators in the U.S."[244]

192. The BCSEA has recommended the expansion of the FEU's EEC portfolio.[245] However, BCSEA's suggestion is not accompanied by details of a plan that would support this increased level of expenditure.[246] Rather, the BCSEA's suggestion that the FEU increase expenditures to equal 1% of sales is based on comparisons to the amount of savings industry leaders in gas DSM have achieved and are planning to achieve.[247] In response to information requests, BCSEA was not able to produce the data to show that DSM programs of these industry leaders are comparable to the FEU's.[248]

193. The FEU's 2014-2018 EEC Plan and budgets reflect reasonable expectations about what it can achieve in BC over the next 5 years. The FEU have been expanding their EEC portfolio since 2009, but the FEU have not yet been able to reach the levels of expenditures being sought over the 2014-2018 period.[249] The FEU's 2014-2018 EEC Plan includes all measures in the CPR with the exception of three, for the reasons explained above. (The BCSEA supports the approach and key assumptions in the FEU's CPR.[250]) In short, the FEU's proposed level of expectations reflects the FEU's experience with DSM in BC, what is achievable in this market and what the Commission has been willing to approve in this jurisdiction.

(c) Updated CPR

194. An updated CPR will provide a new starting point for the EEC budget. An updated CPR (planned at the time of writing to include both gas and electricity conservation potential) will provide a comprehensive assessment of the technologies available and the

[244] Exhibit C4-8.

[245] Exhibit C4-8, pp. 32 to 40.

[246] Exhibit C4-14, FEI/FBC-BCSEA IR 1.19.2.

[247] Exhibit C4-13, BCUC-BCSEA IR 1.3.1.1; Exhibit C4-15, BCPSO-BCSEA IRs 1.6.3, 1.6.4 and 1.6.5.

[248] Exhibit C4-14, FEI/FBC-BCSEA IR 1.11 and 1.12.

[249] Exhibit B-11, BCUC IR 1.212.6.

[250] Exhibit C4-13, BCUC-BCSEA IR 1.3.1.2.

magnitude of the potential for cost-effective gas and electric DSM activity in British Columbia in the time period 2018 forward.[251] The timing for the next CPR is well aligned with the development of an EEC Plan and Funding Request for the post-2018 time period.[252]

(d) Summary

195. The FEU have proposed a level of expenditures that allows it to carry out the cost-effective DSM programs revealed by the last CPR. As these programs are by and large a continuation of previously approved programs, the FEU have taken the Commission's previously approved levels as a guide for what is appropriate and the level of rate impact that is acceptable. The expenditure levels are supported by a detailed program-by-program budget as set out in the 2014-2018 EEC Plan and the expenditure levels have not constrained the development of any EEC programs. Metrics for comparison to other utilities generally show that FEU's proposal is reasonable in the industry. If during the term of the PBR Period, the FEU require more EEC expenditures than sought, the FEU will return to the Commission for acceptance of further expenditures. As such the FEU submit that they have filed a robust EEC plan and have sought a reasonable level of expenditures for the PBR Period.

C. The Five-Year Period of Expenditures is in the Public Interest

196. The FEU are requesting acceptance of five years of expenditures in order to establish certainty in the market that the FEU will be able to offer the programs listed in the EEC Plan over an extended period. This will allow external parties such as contractors, manufacturers and other program partners to better support EEC initiatives knowing that they will be established for the long term. It will also enable FEU to take advantage of program momentum and it will spare EEC resources from extensive regulatory work so they can dedicate their time to program development, refinement and operation.[253]

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[251] Exhibit B-24, BCUC IR 2.369.3.

[252] Exhibit B-24, BCUC IR 2.368.6.

[253] Exhibit B-1-1, Application, Appendix I, p. 17.

197. It is common for utilities to strive towards longer DSM funding approval periods to achieve the benefits associated with maintaining positive program momentum and stakeholder engagement driving market transformation coupled with a reduction of regulatory work such that EEC staff can better focus on program development, refinement and operation activities.[254] Other utilities surveyed had an average DSM funding approval period of 3.37 years. The average was determined across 41 jurisdictions with DSM funding approval periods ranging from 1 to 10 years in length.[255]

198. The EECAG has had the opportunity to review the 5-year 2014-2018 EEC Plan and did not suggest that a shorter period was necessary. There was general agreement that longer-term periods of consistent funding certainty will result in a more effective portfolio, as it will provide certainty to customers, contractors and suppliers of energy equipment and services.[256] As supported by studies conducted by TNS Canada, longevity of EEC programs provides stability in the marketplace, and allows program partners time to become conversant with program parameters and related application processes.[257] The Thermal Environmental Comfort Association ("TECA"), representing more than 300 contractors within the HVAC sector, have provided a letter of support of consistent programming and funding. TECA states:[258]

> "The challenge though for both homeowner and contractor has been the instability of the program funding, changing delivery agents, relatively short program length and the difficult market created from these factors. The unintended result has been customers "holding out" for the next rebate offering - creating spikes and depressions in installations of equipment.
>
> …
>
> We support the plan to offer a more continuous rebate offering as it will create a more level market where customers have an assurance of the programs' reliability and access.

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[254] Exhibit B-24, BCUC IR 2.368.1.1.

[255] Exhibit B-24, BCUC IR 2.368.1.1.

[256] Exhibit B-24, BCUC IR 2.368.1.2.

[257] Exhibit B-7, BCSEA IR 1.12.1.

[258] Exhibit B-7, Attachment 12.1.

> As the industry representing contractors we believe that stable incentive programs will further encourage and support the adoption of energy efficient systems, while preventing frustration and confusion within the market - both with contractors and more importantly, consumers."

199. The FEU submit that this support is significant and that the benefits of a longer period of consistent funding will be beneficial for the FEU's EEC programs.

200. The FEU were questioned regarding how they would deal with changing conditions over the 5-year period. Factors such as the LTRP and CPR will not impact the level of expenditures over the term. As noted above, the timing for the next CPR is well aligned with the development of an EEC Plan and funding request for the post-2018 time period.[259] There is also generally a low probability that potential changes in the operating environment as identified in the IRs would impact the EEC funding or programs.[260] With respect to potential for the estimated cost-effectiveness of a program to change, the FEU responded as follows:[261]

> "The Companies fully expect that the estimated cost-effectiveness of the DSM portfolio will change over the five year PBR period. There are a number of opportunities for the Companies to deal with changing conditions. First, the Director of the EEC group and the EEC Program Managers monitor portfolio and program cost-effectiveness on a monthly basis using a monthly management report. The FEU will adjust programs as necessary to ensure that the EEC portfolio remains cost-effective. Second, the Companies will continue to file the EEC Annual Report by March 31 of each year of the PBR period, and will share annual results for the year previous with the EEC Advisory Group (EECAG), as is our normal course of business today. Finally, should conditions change significantly, resulting in a number of measures, programs, activities, and participation levels becoming cost-effective when they previously were not, the FEU may make an application to the Commission for increased funding levels. The FEU would seek support of the EECAG before making such an application. Combined, these avenues should provide adequate opportunities to address any material changes to cost-effectiveness over the PBR period."

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[259] Exhibit B-24, BCUC IR 2.368.6.

[260] E.g., Exhibit B-24, BCUC IRs 2.368.2 and 2.368.3.

[261] Exhibit B-7, BCSEA IR 1.12.3.

201. The FEU therefore have options to address changing conditions during the 5-year period and can return to the Commission for supplementary funding or program expenditure acceptance if required.

202. It was suggested that a five-year approval was not appropriate because "the FEU shareholder is incentivized on the basis of the EEC $ spend, rather than results achieved."[262] However, a more accurate characterization based on the statutory regime in place is that the utility has an incentive to invest in all cost-effective EEC opportunities. This is because the FEU are only able to proceed with cost-effective EEC programs as determined by the Commission and as prescribed by the DSM Regulation. As such, the FEU's expenditures are supported by cost-effectiveness results on a forecast and retrospective reporting basis. The proposed EEC budget is supported by the 2014-2018 EEC Plan, which is cost-effective under the TRC and mTRC tests in the DSM Regulation. The results from the EEC activity undertaken are bound by the TRC and mTRC test, and have been extensively and transparently reported in the FEU's EEC Annual Reports. Amongst other accountability mechanisms, the FEU consult regularly with the ECAG and follow the EM&V Framework. The FEU therefore only have an incentive to invest in cost-effective EEC programs as determined by the Commission.

203. Each of the employees in the EEC group has performance-related measures in their annual performance plans. The overarching EEC objectives are to meet the mTRC and TRC thresholds while also meeting the EEC program principles (as outlined in the 2008 EEC application). M&E staff with EEC responsibility support this and also have individual measures, examples of which include but are not limited to:[263]

- Full participation in various programs
- Successful submission of EEC Annual Report and Commission approval of EEC ask in RRA

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[262] Exhibit B-24, BCUC IR 2.368.5.

[263] Exhibit B-20, BCSEA IRs 2.8.1 and 2.8.1.1.

- Implement CEO and Contractor Program activities to 75% of approved budget levels for 2013

- Enhance alignments and partnerships, primarily with BC Hydro, post-secondary institutions, FBC electric, and internal groups.

- Provide technical support - including M&V and the assessment and review of energy savings

- Manage project risk, scope and budget

- Look for ways to reduce costs while not compromising quality of M&V work

- Look for ways to improve /streamline the data analysis review and reporting process

- Specific program participation targets for staff with responsibility for program delivery

204. FEI's employee compensation therefore also provides incentives to achieve results.

205. It was suggested that the five-year period was not appropriate because "there is no EM&V approved framework or independent audit of the results."[264] The FEU have reported extensively on the results of its EEC programs in their Annual Reports as directed by the Commission. The FEU have also complied with all Commission directions with respect to an EM&V framework. As discussed in Appendix I of the Application, the FEU has developed an EM&V framework and consulted with the EECAG on the framework as directed by the Commission in the 2012-2013 RRA Decision. As discussed in detail in response to information requests (e.g. BCUC IR 1.214 and 2.371 series), the segregation of the FEU's EM&V activities, the EM&V framework and the use of independent contractors avoids any conflict of interest or

[264] Exhibit B-24, BCUC IR 2.368.5.

bias. While the UCA does not include a requirement for an approved EM&V framework or an independent audit of BC utility energy savings reported, the EM&V framework and the FEU's EM&V results from previous activities are before the Commission in this proceeding. The issue of the EM&V framework is considered further below.

206. It was suggested that a five-year period was not appropriate because the FEU are "incentivized to use EEC funding to improve/maintain the competitive position of natural gas".[265] This incorrectly suggests that the FEU may in some way change their EEC proposals to maintain the competitive position of natural gas. This is simply not the case. Rather, if there is a risk of customers leaving the system to another source of energy due to a higher cost of efficient gas equipment, an incentive will both encourage more efficient consumption of natural gas but also increase the likelihood that the customer will remain a gas customer.[266] Cost-effectiveness criteria, accountability mechanisms such as annual reports, and Commission's review and acceptance of expenditures ensure that the FEU are only putting forward appropriate EEC programs.

207. For these reasons, the FEU submit that the proposed five-year period of expenditures is warranted given the current position of the FEU's EEC portfolio and the need to have stable funding for EEC programs.

D. The Distribution of Expenditures across Customer Classes and Utilities is Equitable

208. The first of the FEU's EEC Guiding Principles is that programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential, commercial and industrial customers, including low-income customers.[267] The second guiding principle is that wherever possible, programs will be uniform, so that customers in one part of the service territories of the FEU have access to the same programs as customers throughout

[265] Exhibit B-24, BCUC IR 2.368.5.

[266] Exhibit B-24, BCUC IR 2.363.1.

[267] Exhibit B-1-1, Appendix I, p. 21.

the service territories. Information requests explored the extent to which the FEU met these principles.

(a) Allocation Amongst Customer Classes

209. The FEU have provided summaries of spending by customer class in BCUC IRs 1.234.7 and 2.369.6. The split of EEC expenditures by customer class can be reviewed by customer count, by volume and by revenue. Customer count is the basis on which the non-incentive, non-utility-specific expenditures are allocated between the utilities.[268] Volume is recognized by the FEU in the levels of EEC funding projected for the different customer classes. For example, it can be seen in the response to BCUC IR 1.234.7 that in 2014, residential customers of FEI are projected to account for 39% of total volumes, and 31% of EEC expenditure, while commercial customers are projected to account for 28% of volume, and 32% of EEC expenditure. Industrial customers account for 32.6% of volume, and 6% of EEC expenditure. The lower proportional spending on industrial EEC is primarily due to the fact that the FEU are in the process of ramping up and learning about industrial EEC after receiving approval for industrial EEC activity in the 2010-2011 revenue requirement proceeding.[269]

210. The FEU's EEC spending as a percentage of revenue for each FEU utility and as percentage of revenue for each customer class appears to match the range for other utilities offering EEC. DSM expenditures, as a percentage of customer class revenue, are approximately in the 2% to 3% range for other utilities from which information could be gathered. This is similar to the range for the FEU as shown in BCUC IR 2.369.6.[270]

211. In terms of revenue, it can be seen in the response to BCUC IR 2.369.6 that in 2014 the FEU are proposing a fairly even distribution of EEC spending as a percentage of customer class revenues.[271] EEC spending as a percentage of revenue is weighted higher

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[268] Exhibit B-24, BCUC IR 2.369.7.

[269] Exhibit B-24, BCUC IR 2.364.4.2.

[270] Exhibit B-24, BCUC IR 2.369.6.2.

[271] Exhibit B-24, BCUC IR 2.364.4.2.

towards Residential customers in 2012 with the percentages for the Commercial and Industrial areas increasing in the 2014 and 2018 periods. This is the case across all the utilities. The main explanation for this variation is that EEC Residential programs for the most part are currently more mature than those in the Commercial and Industrial areas. As the FEU enter into the PBR period, it is projected that Commercial and Industrial EEC expenditures will experience increases over this period compared to 2012.[272] Commercial and industrial programs are addressed further in the following sections.

Commercial Programs

212. Information requests expressed concern that the level of expenditures in 2012 and 2013 in the New Construction and Retrofit programs in the Commercial Program Area were below forecast.[273] The FEU explained that there were competing priorities and staffing constraints which led to a delay in launching these programs. Despite these competing priorities and constraints, the FEU negotiated and signed a program alignment agreement with BC Hydro for the Commercial Custom Design - New Construction program in July of 2011 and were able to bring the program to market in January 2012. The FEU also brought to market the Commercial Custom Design Program for Retrofit Projects in July of 2013.[274] The FEU are not anticipating any constraints on its commercial programs over the 2014-2018 period, as the FEU now have a sufficient commercial team in place and are not planning the launch of any significant new programs.[275]

213. The FEU's proposed five-year period of expenditures will help ensure increased participation in the Commercial Program Area. Commercial upgrades can be complex and can have long lead times. Maintaining stable funding over a period of years is essential in order to encourage commercial customers to participate in the programs and implement natural gas conservation measures. The program terms and conditions are clear that the FEU's ability to

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[272] Exhibit B-24, BCUC IR 2.369.6.1.

[273] Exhibit B-23, CEC IRs 2.92.3, 2.92.4, 2.92.4.1, 2.92.4.2, 2.92.7, 2.92.8 and 2.92.8.1.

[274] Exhibit B-23, CEC IR 2.92.3.

[275] Exhibit B-23, CEC IR 2.92.3.

provide incentives is contingent upon ongoing approval by the Commission. To date funding has been stable, and customers are increasingly taking advantage of the programs. If funding commitments were to become suspect, however, it is unlikely that commercial customers would adapt their operations to participate in the programs.[276]

Industrial Programs

214. Information requests expressed concern regarding the participation rates in the industrial programs and what the FEU are doing to increase this participation. Although in 2012 only one industrial customer received incentives towards the implementation of an energy efficiency project in the Technology Retrofit program, this is reasonable given the complex nature of industrial energy efficiency projects, the long lead times and the time at which the Industrial Program area started. Since being staffed in Q2 of 2010, the FEU have developed and launched industrial programs, identified and contacted potential participants, and have had eligible customers enrolled. Once enrolled, program participants have to hire qualified consultants to identify efficiency opportunities in their facilities, implement the energy efficiency projects, and have the results subsequently validated by the FEU. Industrial energy efficiency projects tend to be more complex and diverse than those in other program areas. These projects can require specialized consultants, as well as parts and equipment custom designed and manufactured for each application. Program enrolment contracts or agreements generally require some customization to suit each project as industrial projects usually present differing technical and financial conditions. Hence, a significant timeframe is required to move a project through to the point of incentive pay out.[277]

215. While only one customer has received an incentive in 2012, this is not indicative of the overall progress and interest in the program. To generate participation from Industrial account managers, the FEU have been promoting EEC industrial offerings and analyzing

[276] Exhibit B-8, CEC IR 1.80.1; Exhibit B-23, CEC IRs 2.92.9 and 2.92.11.

[277] Exhibit B-11, BCUC IR 1.233.8.

potential energy efficiency projects to more than 39 industrial customers.[278] The FEU have 17 industrial customers participating in EEC's industrial programs. Three industrial customers have been preapproved for implementation funds and will most likely receive incentives before the end of 2013. Also, 14 industrial customers have been approved for funds towards an energy audit and the FEU expect to provide incentives for these audits.[279]

216. Uptake in the program is not due to a lack of targeting of customers. The FEU's industrial programs offer analysis, recommendations and incentives targeted at the individual needs of each EEC industrial program participant. Participants are eligible to receive funds towards detailed energy audits targeting inefficiencies specific to their facilities, as well as incentives calculated based on costs and savings specific to each of their energy saving upgrade projects.[280]

217. Efforts to accelerate the uptake of EEC industrial programs include broadening the funding options towards identifying energy efficiency opportunities, as well as making programs available for more prescriptive measures as provided in the 2014-2018 EEC Plan. The FEU also seek to achieve higher participation by collaborating with FBC and BC Hydro. The FEU and FBC jointly approach industrial customers to offer funds towards a single audit process for customers inside FBC's service region. Further, the FEU and BC Hydro plan to offer its industrial customers a single process when applying to receive funds towards assessments, audits and specific studies.[281]

(b) Allocation Amongst the Utilities

218. The allocation amongst the utilities presented in the 2014-2018 EEC Plan and in the response to BCUC IR 2.369.6 are on a forecast basis and are on the basis of the previously-approved allocation using average customer count, which is approximately 89% to Mainland,

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[278] Exhibit B-11, BCUC IR 1.233.8.1

[279] Exhibit B-11, BCUC IR 1.233.8.1.

[280] Exhibit B-24, BCUC IR 2.364.5.2.

[281] Exhibit B-11, BCUC IR 1.233.8.1.

10% to Vancouver Island and 1% to Whistler.[282] The FEU's proposed approach to allocating *actual* expenditures is as follows:

(a) non-incentive expenditures that cannot be attributed to a particular utility over the test period will be allocated as per the previously-approved split based on an average customer basis, count, which is approximately 89% to Mainland, 10% to Vancouver Island and 1% to Whistler; and

(b) the actual incentive expenditures and any expenditures that can be allocated specifically to a particular utility will be allocated on an as-incurred basis.

Since all programs are available to all customers across all service territories, all customers have the opportunity to access and to benefit from all programs for which they are eligible. The opportunities for EEC in FEW's service territory and industrial opportunities in FEW and FEVI's service territories are discussed in BCUC IR 2.369.7. Any EEC expenditures that can be allocated to a particular utility will be allocated on an as-incurred basis to that utility, thus reflecting the costs of the EEC benefits received by that utility.[283]

219. FEI notes that the Commission has granted approval of the amalgamation of FEI, FEVI and FEW, which is planned to be effective January 1, 2015.[284] After amalgamation, allocations between FEI, FEVI and FEW will be unnecessary.

E. The 2014-2018 EEC Plan is "Adequate" Pursuant to the DSM Regulation

220. The DSM Regulation issued under the UCA prescribes that a public utility's "plan portfolio"[285] is adequate if the plan portfolio includes all of the following:

[282] Exhibit B-24, BCUC IR 2.369.7.

[283] Exhibit B-24, BCUC IR 2.369.7.

[284] Order G-21-14, dated February 26, 2014.

[285] The Regulation defines a "plan portfolio" as the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act.

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) an education program for students enrolled in post-secondary institutions in the public utility's service area.

221. Although the “adequacy” requirement under the regulation is with respect to the long-term resource plan requirement under section 44.1 of the UCA, the FEU explained why its EEC program meets the adequacy requirements of the Regulation in its application.[286]

222. In the following sections the FEU address each of the specific adequacy requirements with a focus on the issues raised through the information request process. The FEU submits that its EEC program meets the adequacy requirement in the Regulation.

(a) Low Income Programs

223. The FEU’s 2014-2018 EEC Plan meets the requirement of Section 3(a) of the DSM Regulation that a public utility’s plan portfolio include a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption. The FEU have identified the specific demand-side measures that address this requirement. These include the Energy Saving Kit Program, the new Energy Conservation Assistance Program (“ECAP”) as well as three additional programs proposed for 2014-2018: the Low Income Space Heat Top-Ups, Low Income Water Heating Top-Ups and Non-Profit Custom Program.[287]

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[286] Exhibit B-1-1, Appendix I, pp. 6-7.

[287] Exhibit B-1-1, Appendix I, pp. 6-7; Exhibit B-11, BCUC IR 1.239.1; Exhibit B-24, BCUC 2.379.1.

(b) Rental Accommodations

224. The FEU's 2014-2018 EEC Plan meets the requirement of Section 3(b) of the DSM Regulation that a public utility's plan portfolio include a demand-side measure intended specifically to improve the energy efficiency of rental accommodations. The FEU have identified the demand-side measures that address this requirement. These include all of the programs in the FEU's Residential Program Area, as well as several programs in the Commercial Program Area that target rental accommodations, such as the Space Heat Program, the Water Heating Program and the Commercial Energy Assessment program.[288]

225. IRs that appeared to question whether the FEU met the DSM Regulation's requirement appear to be premised on the incorrect assumption that section 3(b) of the DSM Regulation requires programs that are *exclusively* for rental accommodations. The requirement in the DSM Regulation, however, is for programs intended *specifically* to improve the energy efficiency of rental accommodations. The FEU submit that their EEC programs meets this requirement. For example:[289]

(a) Energy Specialists, through the Energy Specialist Program, are placed at BC Housing and the BC Non-Profit Housing Association.

(b) The Energy Savings Kit program streams participants living in an apartment (generally renters in this low-income program) through to an energy savings kit that includes only the measures specifically suited to apartment units.

226. The FEU's compliance with section 3(b) of the DSM Regulation is further demonstrated by the fact that an analysis of the participation in FEU's programs from January 2012 to October 2013 shows an estimated:

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[288] Exhibit B-1-1, Application, Appendix I, p. 7, Exhibit B-11, BCUC IR 1.239.1 (Table 2); Exhibit B-24, BCUC 2.379.1.

[289] See Exhibit B-7, BCSEA IR 1.15.1 for a more detailed discussion of these examples and others.

(a) 1,000 rental units (146 buildings) benefited from the Commercial programs (based on Efficient Boiler Program and Efficient Commercial Water Heater Program only);

(b) 5,000 rental units (mixed apartments and other home types) benefited from the Residential programs; and

(c) 6,000 rental units (mixed apartments and other home types) benefited from the Low Income programs.[290]

227. These 2012-2013 programs are proposed to continue in the 2014-2018 EEC Plan.[291]

228. According to a preliminary scan of a database of more than 3,000 DSM and renewable energy programs in Canada and USA, the vast majority of programs for this market segment are commercial, residential, or low-income programs that are made available to rental accommodations. Only 3 programs were exclusively available to rental accommodations.[292]

229. The FEU therefore submit that its 2014-2018 EEC Plan meets the requirement to include demand-side measures intended specifically to improve the energy efficiency of rental accommodations.

(c) Education Programs

230. The FEU's proposed 2014-2018 EEC Plan meets the requirement of Sections 3(c) and (d) of the DSM Regulation that a public utility's plan portfolio include education programs for students enrolled in schools and post-secondary institutions in the public utility's service areas.

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290 Exhibit B-24, BCUC IRs 2.379.3 and 2.379.3.1.

291 Exhibit B-1-1, Appendix I, Attachment I1, 2014-2018 EEC Plan.

292 Exhibit B-24, BCUC IR 2.379.3.

231. The FEU have specifically identified the specific demand-side measures that address the adequacy requirements in the DSM Regulation, including EEC education program for students enrolled in schools in the FEU's service areas.[293] The FEU fund a variety of education programs for K-12 students enrolled in its service areas through Conservation Education and Outreach initiatives. There are also a number of initiatives specifically targeting post-secondary students, encouraging them to learn and apply their knowledge of natural gas energy conservation through interactive competitions. Examples include encouraging campus residents to take shorter showers and 'Shut the Sash' campaigns on chemistry lab fume hoods.[294]

232. The FEU submit that their EEC program meets the DSM Regulation's requirement to include education programs for students enrolled in schools and post-secondary institutions in the public utility's service areas.

F. The 2014-2018 EEC Plan is Cost Effective

233. FEI's proposed 2014-2018 EEC Plan is cost-effective on a portfolio basis using the TRC and mTRC as prescribed by the DSM Regulation. This represents the cost-effectiveness approach consistently used and approved by the Commission since the FEU's first 2008 EEC application, in Order G-36-09, Order G-141-109, and Order G-44-12. This section will first provide an overview of the cost-effectiveness approach and then turn to the issues raised in the proceeding.

234. 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.[295] The FEU have described the approach to cost-effectiveness prescribed by the DSM Regulation and previously approved by the Commission in

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[293] Exhibit B-11, BCUC IR 1.239.1 (Table 3); Exhibit B-24, BCUC IR 2.379.1.

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

[295] UCA, Section 44.2(5)(d).

section 6 of Appendix I of the Application.[296] As the DSM Regulation is quite complex, the following summarizes the key parameters:

(a) **Portfolio Analysis**: The Commission may consider cost-effectiveness of demand-side measures individually, in a group, or as a portfolio as a whole.[297] However, "specified demand-side measures" and "public awareness programs" must be considered on a portfolio basis.[298] The Commission has consistently chosen to consider the cost-effectiveness of demand side measures as a portfolio. The FEU supports the continued use of the portfolio approach, which promotes the goal of making EEC accessible to all customers and allows the FEU to encourage increasing levels of efficiency in natural gas equipment.[299]

(b) **TRC/mTRC**: The TRC/mTRC indicates whether the benefits to British Columbians generally from undertaking an EEC activity outweigh the costs of doing so.[300] The Commission must make a determination of cost effectiveness using the TRC as modified by the DSM Regulation in two ways (the mTRC): (a) The value of the discounted total net benefits of the program is calculated based on 50% of BC Hydro's long term marginal cost for acquiring electricity generated from clean or renewable resources in BC, rather than the cost of regular gas supply. (b) A 15% adder is added on top of the total net benefits recognizing additional non-energy benefits, such as water savings and job creation that result from the program being in the market.[301] Up to 33% of total expenditures for the portfolio can rely

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[296] Exhibit B-1-1, Appendix I, pp. 23 to 28.

[297] DSM Regulation, Section 4(1).

[298] "Specified demand-side measures" include: education programs for students, funding for energy efficiency training, a community engagement program and a technology innovation program. 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.

[299] Exhibit B-1-1, Appendix I, pp. 24-25.

[300] Exhibit B-24, BCUC IR 2.366.1.

[301] DSM Regulation, Section 4(1.1).

on the mTRC for a determination of cost-effectiveness.[302] The FEU's portfolio is cost-effective using the TRC/mTRC and does not exceed the 33% mTRC cap.[303]

(c) **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 TRC test and consider the benefit of the demand-side measure to be 130% of its value. As clarified in FEI's EEC Evidentiary Update, Low Income Programs are subject to the mTRC. FEI explained as follows:[304]

> "Section 4(2) of the DSM Regulation states that in determining whether a Low Income Program is cost-effective, the Commission must use the TRC. Section 4(1.1) of the DSM Regulation, in turn, specifies how the Commission is to apply the TRC. Accordingly, pursuant to Section 4(1.1)(a) of the DSM Regulation, the total resource cost effectiveness of a Low Income Program that does not pass the TRC when using the 30% benefit adder, can be determined by using the long-run marginal cost of acquiring electricity generated from clean or renewable resources, multiplied by 0.5 (known as "the Zero Emission Energy Alternative", or "ZEEA"). Further, pursuant to DSM Regulation section 4(2)(b), low income programs are also to consider the benefit of the demand side measure to be 130% of the value that would normally be recognized in a non-low income program. In summary, section 4(2) and 4(1.1) read together indicate that Low Income Programs are eligible for the mTRC treatment utilizing the 30% benefit adder for low income programs instead of the 15% adder that is used when applying the mTRC to non-Low Income programs. The FEU recognize that use of the mTRC remains limited to 33% of the EEC portfolio, including Low Income Programs."

The FEU's Low Income Programs are cost-effective using the mTRC.[305]

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[302] DSM Regulation, Section 4(1.5).

[303] Exhibit B-24, BCUC IR 2.366.6.

[304] Exhibit B-43, FEU's EEC Evidentiary Update, p. 2.

[305] Exhibit B-43, FEU's EEC Evidentiary Update.

(d) **Utilities Cost Test ("UCT")**: The UCT assesses whether the benefits to the utility of undertaking an EEC activity outweigh the costs to the utility.[306] Despite the requirement to use the TRC/mTRC, the Commission may determine that a demand-side measure is not cost effective using the UCT, except for a "specified demand-side measure," a "public awareness program", "a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption" and a demand-side measure that is cost-effective under the TRC (i.e. without the modifications of the mTRC described above).[307] The Commission has to date not used the UCT to determine that any of the FEU's EEC programs are not cost-effective.

(e) **Ratepayer Impact Measure ("RIM") Test**: The RIM test assesses the cost-effectiveness of DSM programs from the sole perspective of the costs and benefits to utility ratepayers. The Commission cannot find a demand-side measure not to be cost-effective because it fails the RIM test.[308]

235. The FEU submit that the evidence in this proceeding supports continued use of the cost-effectiveness approach previously used and approved by the Commission. The FEU therefore submit that the Commission should find that, on the basis of the FEU's 2014-2018 EEC Plan and supporting evidence in this proceeding, the FEU's proposed EEC expenditures are cost-effective using the TRC/mTRC on a portfolio basis.

236. In the proceeding, issues with respect to cost-effectiveness centered on the use of the UCT, components of the TRC/mTRC test and the use of spillover effects. These are addressed below.

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[306] Exhibit B-11, BCUC IR 1.219.2; Exhibit B-24, BCUC IR 2.366.1.

[307] DSM Regulation, Section 4(1.8). Note also that a DSM measure that passes the TRC with the aid of Section 4(1.4) is also not subject to the UCT.

[308] DSM Regulation, Section 4(6).

(a) Utility Cost Test Should not be Used to Determine Cost Effectiveness

237. As explained above, the FEU consider that the appropriate way to determine the cost effectiveness of EEC programs is to apply the TRC/mTRC test at the portfolio level. While the DSM Regulation gives the Commission discretion to use the UCT, the Commission has to date not determined that any of the FEU's programs are not cost-effective due to the UCT. The use of the UCT is also limited by the DSM Regulation and, notably, does not apply to DSM measures that are cost-effective using the TRC.[309]

238. As explained by BCSEA in response to BCUC-BCSEA IR 1.1.2, the DSM Regulation does *not* express a "preference" that EEC programs pass the Utility Cost Test. BCSEA appropriately points to the DSM Regulation Guide which states that the DSM Regulation "does not suggest the commission must or should" determine that a measure that fails the UCT is not cost effective.[310]

239. It is useful to calculate and monitor other cost effectiveness tests such as the UCT both at the portfolio and individual program level, as these cost effectiveness tests can provide information about the impacts of EEC programs from different perspectives. However, these other tests should not be applied to determine whether a program is implemented or not. Rather, the benefits of EEC investments are better optimized by having a robust portfolio of programs working together to provide all customers with access to programs while achieving energy savings. Setting additional cost effectiveness rules at the program level could result in the removal of important supporting programs or could reduce accessibility to programs, compromising the effectiveness of the portfolio as a whole.[311]

240. It was suggested, however, that the TRC/mTRC should not be the only measure to determine cost-effectiveness because the level of EEC incentive does not affect the

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[309] DSM Regulation, 4(1.8).

[310] Exhibit C4-13, BCUC-BCSEA IR 1.1.2.

[311] Exhibit B-11, BCUC IR 1.217.5.2.

TRC/mTRC result.[312] Since the TRC/mTRC examine the cost effectiveness of EEC Programs from the societal perspective, all incremental costs - no matter who pays them - are taken into account. Therefore, the level of incentive does not affect the TRC/mTRC results. This is standard industry practice.[313]

241. The appropriate way to set program incentive levels is by using market research and good program design approaches, rather than by applying additional cost effectiveness hurdles at the program or portfolio levels. This approach will allow incentives to be set based on the objectives of the program and challenges in the market place to program success, rather than by their impact on rigid cost effectiveness rules. The strength of the program design and approval process that the FEU has in place and the transparency with which EEC activities are reported will both continue to ensure that incentive levels are set appropriately.[314]

242. It was also suggested that the UCT with recognition of environmental benefits would be appropriate.[315] The FEU agree with the BCSEA's response to this suggestion including that the simplest way to incorporate environmental benefits is to rely on the mTRC and refrain from using the UCT. As noted by BCSEA, the purpose of the mTRC is to modify the TRC to take into account the GHG reduction and non-energy benefits.[316]

243. Since the TRC/mTRC examine the cost effectiveness of EEC Programs from the societal perspective, the FEU believe that the current approach of determining the cost effectiveness of EEC programs by using the TRC/mTRC at the portfolio level remains appropriate for the 2014-2018 EEC Plan period.[317]

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[312] Exhibit B-11, BCUC IR 1.217.5.2.

[313] E.g., Exhibit B-11-1, Attachment 217.2, "Understanding Cost-Effectiveness of Energy Efficiency Programs", p. 6-6.

[314] Exhibit B-11, BCUC IR 1.217.5.2.

[315] Exhibit C4-13, BCUC-BCSEA IR 1.1.2.1.

[316] Exhibit C4-13, BCUC-BCSEA IRs 1.1.2.1.1 and 1.2.3.1.

[317] Exhibit B-11, BCUC IR 1.217.5.2.

(b) Components of the TRC/mTRC

244. The FEU have provided detailed information on how it calculates the TRC and mTRC. The FEU calculate the TRC as a benefit-cost ratio of the discounted total net benefits of the program to the total net costs over a specified time period. The benefits calculated in the TRC are the avoided supply costs of the gas that would otherwise be delivered to the customer in the absence of the program.[318] The costs in this test are the incremental costs (the cost to install the incented equipment over what would otherwise have been installed in the absence of the program) and the administration costs for the program. All incremental costs such as equipment costs, installation, operation and maintenance, cost of equipment removal no matter who pays for them, are included in this test.

BC Hydro's Long-Run Marginal Cost

245. One of the components of the mTRC is the use of a zero-emission energy supply alternative ("ZEAA") in determining the avoided cost of energy for DSM.[319] The FEU have explained the use of the ZEAA on page 25 of Appendix I of the Application. As indicated there, the FEU have used a value of $129/MWh x 0.5 for the ZEEA and BC Hydro has confirmed that this is the value for the Long Run Marginal Cost of clean or renewable power.[320] Information requests focussed on the potential for BC Hydro's Long Run Marginal Cost of clean or renewable power to change.

246. During the second of round of IRs, the FEU were asked whether the ZEEA should be updated to reflect BC Hydro's changes to its estimated long-run marginal cost of clean or renewable power. The FEU indicated that they were not aware that BC Hydro has arrived at a final determination of its long-run marginal cost of clean or renewable power. The FEU also

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[318] See the response to BCUC IR 1.218.2 (Exhibit B-11) for an explanation of the avoided cost of gas in the conventional TRC.

[319] Exhibit B-1-1, Application, Appendix I, p. 25.

[320] Exhibit B-11, BCUC IR 1.218.3. The source for the figure is BC Hydro's October 2010 Report on the RFP Process for the Clean Power Call Request for Proposal. Please refer to Table 3-5 on page 12 of Attachment 218.3 (Exhibit B-11-1).

provided an analysis of the impact on its 2014-2018 EEC Plan if the long-run marginal costs were to change.[321]

247. As the FEU have committed to in previous proceeding, the FEU will monitor cost-effectiveness results monthly to ensure the portfolio remains cost effective using the TRC/mTRC as prescribed in the DSM Regulation, and will report on program results in the EEC Annual Report. When monitoring cost-effectiveness results, the FEU will use BC Hydro's most recent long-run marginal cost for clean power over the PBR period and adjust the ZEEA in accordance with the mTRC set out in the DSM Regulation. The benefit-cost analysis for EEC programs requiring the use of the mTRC would be re-run accordingly and programs not found to be cost-effective would not run.[322]

248. In summary, if there is a change in the DSM Regulation or other cost-effectiveness criteria over the course of a test period, the FEU's commitment to oversee cost-effectiveness results regularly and meet cost-effectiveness criteria on an actual basis manages the potential for such changes. The FEU will continue to report on actual results in their EEC Annual Reports as previously directed by the Commission.

Discount Rate

249. Information requests also inquired into the appropriate discount rate for the TRC/mTRC. The discount rate that the FEU use for the TRC/mTRC calculation is the utility's pre-tax WACC adjusted for inflation. For 2013, these values are 6.44% for FEI and 6.57% for FEVI.[323] The use of the utilities' WACC represents the same carrying costs as if the FEU were investing in capital assets. A pre-tax WACC adjusted for inflation is used because the FEU also use program input costs and benefits determined on a pre-tax basis.[324] Use of the utilities' pre-tax WACC as the discount rate for evaluating EEC activities has been well documented and reviewed in prior

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[321] Exhibit B-24, BCUC IRs 2.370.1 and 2.370.1.1.

[322] Exhibit B-24, BCUC IR 2.370.1.

[323] Exhibit B-11, BCUC IR 1.218.6. Also see page 4-8 of Attachment 217.2 provided in the response to BCUC IR 1.217 (Exhibit B-11-1).

[324] Exhibit B-24, BCUC IR 2.370.2.

regulatory proceedings.[325] A survey of the practices of other jurisdictions found that 49% of utilities surveyed used the utilities' WACC.[326]

250. The topic of a social discount rate was also raised in IRs. The FEU put forward the use of a 3% social discount rate in the 2012-2013 RRA proceeding, but this proposal was withdrawn as a result of the changes made to the DSM Regulation.[327] The use of the mTRC as prescribed in the DSM Regulation (with the ZEAA as the avoided cost, and a 15% adder to the benefits side of the equation for those programs that fail the TRC, up to 33% of the EEC portfolio), has a similar effect as that of using a societal discount rate in the TRC calculation.[328] As such, the FEU continues to consider it more appropriate to use the mTRC, rather than a societal discount rate for the TRC.

251. The FEU submit that the FEU's discount is appropriate and should be continued to be used for cost-effectiveness test purposes.

Avoided Cost of Gas

252. The FEU have explained how it calculates its avoided cost of natural gas in BCUC IR 1.218.2, with further explanation in the BCUC IR 2.384 series. As explained in those IRs, the FEU use an avoided cost of gas based on gas commodity and midstream transportation, storage and other costs in the TRC calculation. As emphasized in those responses, the calculation should be to derive an *avoided* or *marginal* cost of gas, rather than an average cost of gas.[329]

253. The evidence shows that there is no industry standard practice for calculating the avoided cost of gas.[330] While in interest of simplicity some immaterial components of the

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[325] Exhibit B-24, BCUC IR 2.370.2.

[326] Exhibit B-24, BCUC IR 2.370.2.

[327] Exhibit B-24, BCUC IR 2.370.3.

[328] Exhibit B-11, BCUC IR 1.218.6.1.

[329] E.g., Exhibit B-24, BCUC IR 2.384.8.3.

[330] Exhibit B-24, BCUC IR 2.384.9.1.

cost of gas were not included in the calculation,[331] the FEU's calculation includes elements common to many utilities and is an appropriate methodology.[332]

254. The suggestion that a weighted average of FEI's commodity rates for 2013 should be used is not appropriate as it would not be an accurate representation of the 2013 Commodity Cost on the FEI system. FEI explained that a weighted average of FEI's commodity rates for 2013 would not only include the impacts of CCRA deferral account balances along with the forecast of the commodity costs, but the underlying forecast commodity costs embedded in rates reflects a rolling 12-month prospective period. Deferral account balances, whether surplus or deficit balances, can result in commodity rates that are materially different than FEI's commodity costs.[333]

255. Further, the suggestion that a receipt point allocation be used in determining the calculation of the 2013 Commodity Cost component of $3.839/GJ in the avoided cost of gas calculation is incorrect as the avoided cost of gas calculation is meant to represent the marginal or most expensive, rather than the average, cost in the gas portfolio. To calculate the marginal or most expensive cost in the gas portfolio, FEI instead derived a Sumas price for the commodity component. This derived Sumas price is based on the GLJ Petroleum Consultants ("GLJ") AECO/NIT price forecast, then adding the AECO/NIT-Station 2 differential and T-South pipeline fuel to determine a Sumas price equivalent.[334] In any case, the alternative cost of gas suggested does not result in a materially different result.[335]

256. The FEU submit that it has used a reasonable calculation of the avoided cost of gas and that no alternative methodologies considered actually result in a materially different result.

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[331] Exhibit B-24, BCUC IR 2.384.5.

[332] Exhibit B-24, BCUC IR 2.384.9.1.

[333] Exhibit B-24, BCUC IR 2.384.8.3.

[334] Exhibit B-24, BCUC IR 2.384.6.

[335] Exhibit B-24, BCUC IR 2.384.11.2.1.

(c) Net-to-Gross Ratio: Spillover and Free Riders

257. The FEU discuss the net-to-gross ratio, including spillover and free riders on page 26 of Appendix I of the Application. As described there, in addition to accounting for free riders, the FEU believe that net-to-gross ratio should account for spillover, i.e. the benefits of customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, although they do not actually participate in the incentive program. In the 2012-2013 RRA Decision the Commission determined that it would not be appropriate to make a determination of the inclusion of spillover without a full assessment of the merits based on a specific set of facts. Thus, the FEU are requesting endorsement of the recognition of spillover effects on a case-by-case basis where evaluation shows that spillover is occurring.

258. The FEU plan to evaluate program effects on a program-by-program basis, using consultants to conduct surveys of program participants and non-participants, to determine both free rider rates and spillover effects. Spillover rates are difficult to measure in that they are primarily determined by surveying individuals as to the effect that a utility DSM program has had on the respondent's actions, generally a significant amount of time after the action has been undertaken. However, by not accounting for program spillover effects and only adjusting program results downward for free rider effects, which are also notoriously subjective, evaluation of the FEU's programs is creating a lopsided view of the FEU's EEC activity.[336] The FEU plans to further explore the applicability of alternate methods for calculating the net-to-gross ratio.[337]

259. The 2014-2018 EEC Plan includes a spillover rate for one program, the Residential Energy Efficient Home Performance Program, historically known as LiveSmart BC. Evaluation of spillover for the LiveSmart program has been possible as a result of BC Hydro's

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[336] Exhibit B-24, BCUC IR 2.378.1.

[337] Exhibit B-24, BCUC IR 2.378.4.

experience and work on evaluating spillover effects for this program.[338] The methodology used to estimate spillover was as follows:

> "The LiveSmart BC evaluation collected information on participant experience and satisfaction, in comparison to non-participant decision-making on home retrofits to inform free rider and spillover estimates. Additional demographic and housing parameters were collected for both customer satisfaction attributes and for billing consumption analysis. A print and online survey methodology was selected to afford respondents the time to formulate and express well-considered responses to the number of complex questions being asked of them.
>
> The LiveSmart participant population was all households in British Columbia that completed home retrofits and received program rebates via LiveSmart within the evaluation period. A near-census approach was primarily used to ensure a very large survey sample to facilitate a billing analysis down to the measure level and in consideration of lower response rates typically associated with self-administered surveys. This large sample size also facilitated a detailed analysis of free-ridership and spillover. A small portion of households were excluded due to the following: participants on the 'do not consent' list, households from smaller local distribution company territories, and reasons relating to inconsistent or incomplete program information. A total of 28,254 program participants were mailed a survey with 8,631 surveys completed and returned.
>
> For non-participants, a sample of program eligible households was randomly drawn from the BC Hydro and FortisBC customer billing systems. A total of 29,469 non-participating households were mailed a survey and 4,457 surveys were completed and returned.
>
> The samples of survey respondents were then compared to the population of participants and non-participants to ensure they were representative".

260. While the statistical evaluation results were not available during the proceeding, the program evaluation team has indicated that there were spillover effects in both participant and non-participant survey groups. Therefore, the FEU has included a conservative 15% spillover rate for this program. FEI plans to update the spillover rate based on the statistical evaluation for LiveSmart BC when it becomes available.[339] The FEU submits that the

[338] Exhibit B-1-1, Appendix I, p. 27 and Exhibit B-11, BCUC IR 1.226.10.
[339] Exhibit B-1-1, Appendix I, p. 27 and Attachment I-1, p. 16.

preliminary survey results are sufficient for the cost-effectiveness test run for this program in the 2014-2018 EEC Plan.

(d) RIM Test

261. Information requests suggested that the FEU were applying a RIM test on a portfolio basis. This is not the case.[340] However, the FEU are mindful of customer rate impact resulting from EEC expenditures. The FEU therefore used the previously accepted 2012-2013 expenditure level as a starting point for the development of the 2014-2018 EEC Plan. This provided the FEU with a level of expenditure with which the Commission Panel appeared to be comfortable and which provided a reasonable balance between the availability of EEC programs and the overall impact on the cost of service and therefore customer rates.[341] Having said this, the FEU refer to their submissions above which show that the proposed level of expenditures has not in fact constrained any EEC programs.

G. Existing Programs are Part of a Cost-Effective Portfolio and are in the Public Interest

262. The majority of the programs in the 2014-2018 EEC Plan have been previously accepted by the Commission. The FEU submit that the existing programs form part of a comprehensive cost-effective portfolio of EEC activities and that the proposed expenditures to continue these programs are in the public interest. The following subsections address what appear to the FEU to be the most material issues raised with respect to the existing programs.

(a) Residential Appliance Service Program

263. Information requests inquired into the benefits of the Residential Appliance Service Program. This program provides customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. In the 2012 Appliance Service program, 13-16% of responders were advised to upgrade their furnace,

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[340] Exhibit B-24, BCUC IR 2.364.3.2.
[341] Exhibit B-24, BCUC IR 2.364.3.2.

while problems (including gas leaks) were discovered in 6-11% of furnaces. In 2013, the Appliance Service program and Furnace Early Replacement Pilot were conducted in parallel. Program evaluation will determine if this co-promotion resulted in driving higher appliance replacement than in previous years. [342]

264. The Appliance Service program results in indirect energy savings, as well-maintained heating systems will operate more efficiently. The program also creates an opportunity for customer and contractor dialogue, to educate customers on energy saving behaviour and promote future gas savings at a relatively low cost to the FEU. The FEU do not attribute direct energy savings to the Appliance Service program, as separating the impact of this program on customer knowledge of energy efficiency and on contractor ability to influence energy equipment choices from the influence of other programs is too difficult.[343]

265. Since participants identified multiple benefits of servicing their appliances annually, including safety, improved efficiency and lower bills, the FEU were asked whether customers were misled by this program.[344] While maintaining a furnace will result in energy savings, the FEU do not promote the Appliance Service program in a way which suggests that participants will experience identifiable annual gas savings. Participant satisfaction with the Appliance Service program continues to be very high with 84% of respondents indicating high to very high satisfaction with the Appliance Service program. As noted in the 2012 Residential End-Use Study ("REUS"), 52% of respondents indicated they were somewhat or very interested in a furnace tune-up program.[345]

266. The FEU submit that the Residential Appliance Service Program results in energy savings as well as non-energy benefits through the maintenance of natural gas equipment and

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[342] Exhibit B-11, BCUC IR 1.226.3.2; Exhibit B-24, BCUC IR 2.374.1.2.

[343] Exhibit B-11, BCUC IRs 1.217.4.2 and 1.226.3, Exhibit B-24, BCUC IR 2.374.1.

[344] Exhibit B-1-1, Appendix I, Attachment I-2, 2012 Annual Report, p. 87, "TLC Furnace/Fireplace 2012"; Exhibit B-24, BCUC IR 2.374.1.1.

[345] Exhibit B-24, BCUC IR 2.374.1.2.

provides a low-cost opportunity for gas contractors to educate customers. As such, expenditures for this program should continue to be accepted.

(b) Energy Star Water Heater and EnerChoice Fireplace Program

267. All EEC programs assume that the baseline condition is a certain level of natural gas use and that participants subsequently install a higher efficient measure or measures which result in a reduction of natural gas consumption compared to the baseline condition. While not actively promoted, the FEU do permit switching from another fuel source to natural gas for the ENERGY STAR® Water Heater Program and the EnerChoice Fireplace Program. However, with both of these programs the FEU assume that participants switching from another fuel source would have switched to natural gas anyway under the baseline condition, but choose to upgrade to a higher efficient model of natural gas appliance than what they would have selected under the baseline condition.[346]

268. In this regard, the FEU have followed the directive outlined in the BCUC Decision and Order No. G-36-09 on the 2008 EEC Programs Application in which the Commission Panel states:

> "The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas. Expenditure programs specifically directed at encouraging fuel switching away from electricity are rejected, as are Incentive payments for appliances for which an Energy Star rating is not available. **However, expenditures are accepted for incentives to install Energy Star and EnerChoice equipment and appliances for customers, who, at their own initiative, wish to switch to natural gas as the fuel of choice".**

269. In accordance with this prior directive, these programs should not be restricted to the replacement of gas or propane appliances and should be permitted to continue as currently being run.

[346] Exhibit B-24, BCUC IR 2.374.6.2.

270. In the case of the Energy Star Water Heater program, for example, customers whom at their own initiative want to replace their electric water heater should be encouraged through this incentive program to install an efficient natural gas water heater rather than an inefficient one. The incentive available under this program is intended to address the cost increment between high-efficiency Energy Star tanks and new technologies rather than the minimum efficiency 0.62 EF base models. This program supports upcoming federal and provincial Efficiency Act standards as part of a long-term market transformation strategy for gas and propane-fired water heaters. All customers will benefit from increased availability and increased education of the trades regarding the installation of these new high-efficiency water-heating technologies.[347] In November 2013, Natural Resources Canada awarded FEU an ENERGY STAR® Market Transformation Award as the Regional Utility of the Year for the market transformation efforts in the Water Heater pilot and program. The award recognizes "leadership in offering Canadian consumers the most energy-efficient products and technology available on the market".[348]

271. The FEU submit that these programs should be permitted to continue as currently configured and as previously accepted and directed by the Commission. The FEU do not promote switching from other energy choices in these programs. If customers, however, choose to switch they should be encouraged to use energy efficient models. These programs accomplish this objective.

(c) Energy Conservation Assistance Program ("ECAP")

272. The ECAP is considered the FEU's "flagship" low-income program. ECAP is a comprehensive whole-house program that the FEU conduct in partnership with BC Hydro and FBC so that opportunities for electricity and gas energy savings are addressed within a single

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[347] Exhibit B-24, BCUC IR 2.374.6.

[348] Exhibit B-24, BCUC IR 2.374.6.

program. ECAP fully facilitates the installation of services through third party contractors and does not require the low-income participant to pay any costs.[349]

273. Concerns were expressed that the expenditures in the ECAP were below previously accepted levels. The underspend in ECAP was due to furnaces not yet being included in ECAP and the fact that the low income sector has been harder to engage in ECAP than originally anticipated which has led to fewer participants in the program.[350] The FEU, FBC and BC Hydro have been re-visioning the overall delivery of the ECAP program and the ECAP is changing in several ways:

(a) ECAP is being expanded to include FBC customers;

(b) The administration of the program is being spread across all three utility partners (formerly BC Hydro was the central administrator);

(c) Barriers to participation are being reduced such as expanding the acceptable documentation for income verification; and

(d) Low Income apartment buildings will be able to qualify for a simplified version of the ECAP program (formerly low income residents of apartments were only serviced by the Energy Saving Kit program).

274. FEU expects that the enhancements being made to the program will aid in improving participation in the program and greater investment in low-income energy efficiency programming. The FEU expect that furnaces will be implemented in ECAP before the end of the first quarter of 2014.[351]

275. Concerns were also expressed about the cost-effectiveness test results of the ECAP. As explained by the FEU in Exhibit B-43, the FEU incorrectly considered low-income

[349] Exhibit B-24, BCUC IR 2.374.4.

[350] Exhibit B-23, CEC IR 2.90.1.

[351] Exhibit B-23, CEC IR 2.90.1.

programs to be exempt from the mTRC. In fact, section 4(2) and 4(1.1) indicate that Low Income Programs are eligible for the mTRC treatment utilizing the 30% benefit adder for low income programs instead of the 15% adder that is used when applying the mTRC to non-Low Income programs.[352] The FEU have revised its evidence, including relevant IR responses, in Exhibit B-43.

276. With this correction, the overall mTRC for ECAP is 1.06. Although the TRC is 0.4, research indicates that many other low-income programs struggle to be cost-effective under the TRC and that many utilities are not required to use cost-effectiveness tests for low-income programs.[353] Furthermore, the societal benefits of offering energy efficiency programs to low-income customers are substantial. The ECAP program is the program that affords low-income customers the largest opportunities for saving energy and affords the greatest environmental, social and economic benefits to society, as well as non-energy benefits of increased health, safety and comfort.[354]

277. An information request asked why the FEU were increasing funding for ECAP by 46% over the PBR Period, while funding for other low-income top-up programs decline.[355] It was suggested that the FEU could instead transfer the proposed increase in ECAP spending over the PBR period to the low-income space and water heating top-up programs, and expand these top-up programs to cover rental dwellings occupied by low-income tenants.[356] The FEU's proposed funding is based on anticipated demand for these programs over the PBR Period. The FEU have proposed increasing ECAP funding from $1.675 million in 2014 to $2.456 million in 2018 because the FEU believe that the ECAP program will take longer to reach the peak demand for the program due to this program having longer engagement cycles with participants. The time between participant approval and the final quality assurance check of the installations can take several months and even longer for engagements with non-profit

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[352] Exhibit B-43, FEU's EEC Evidentiary Update, p. 2.

[353] Exhibit B-24, BCUC IR 2.374.4.1 as amended in Exhibit B-43, FEU's EEC Evidentiary Update.

[354] Exhibit B-24, BCUC IR 2.374.4.1 as amended in Exhibit B-43, FEU's EEC Evidentiary Update.

[355] Exhibit B-24, BCUC IR 2.374.4.2.

[356] Exhibit B-24, BCUC IR 2.374.4.2.1.

societies and First Nations communities.[357] With furnaces being integrated into the ECAP program in 2014, FEU believes the program will become more popular and the funding that has been requested is anticipated to be needed to enable all projected participants to participate in the program.[358]

278. The low-income top-up programs' funding request was also based on projected participation in the program. However, because these are single measure programs, it is expected that participant engagement cycles will be shorter and it is estimated that this will lead to peak program participation in 2016. Further, these programs have a specific target market of Multi-Unit Residential Buildings, primarily non-profit housing societies and provincially or municipally owned low-income buildings.[359] The participation and funding for the top-up programs align with the anticipated demand for the programs, increasing from $93 thousand in 2014 to $111 thousand in 2016 before dropping back to $73 thousand in 2018.[360]

279. The ECAP is the FEU's flagship low-income program and is cost-effective under the mTRC. Although it has a TRC and UCT score below 1.0, this program is the primary program to achieve energy conservation and efficiency in the low-income sector, represents a collaborative effort of FortisBC and BC Hydro, and offers many societal benefits and non-energy benefits to low-income customers as well. The FEU submit that the expenditures for the ECAP should continue to be accepted over the PBR Period.

(b) Furnace Replacement Program

280. While the BCSEA has recommended expanding the Furnace Replacement Program, BCUC IR 2.374.5.1 suggested FEU's funding levels for the program may be too high due to a UCT score of less than 1.0. The FEU's requested funding amount for the Furnace Replacement Program is appropriate and based on the 2012-2013 pilot results, detailed

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357 Exhibit B-24, BCUC IR 2.374.4.2.

358 Exhibit B-24, BCUC IR 2.374.4.2.1.

359 Exhibit B-24, BCUC IR 2.374.4.2.1.

360 Exhibit B-24, BCUC IR 2.374.4.2.

program design and cost-effectiveness considerations. The FEU have spent the past two years evaluating the Furnace Replacement Program to develop a design that is cost-effective and meets the needs of customers and the trades.[361] The FEU's Furnace Replacement Program is based on a pilot study run in 2012 and 2013, as reported in Exhibit B-1-1, Appendix I, Attachment I-5. Based on learning from the pilot as described in the report, the FEU have created a program plan for the Furnace Replacement Program over the PBR Period, which is included in Section 3.4.2 of Attachment I-1 of the Application (Exhibit B-1-1).

281. The Furnace Replacement Program is a cornerstone program in the EEC Residential Program Area and the FEU have requested that the $2 million approved funding for the 2012 and 2013 pilot phase be increased to $3.3 Million per year to fulfill customer demand. In 2012, over 3,000 participants benefitted from the pilot that ran in September and October. In 2013, the FEU estimates that 2,400 participants benefited from the pilot that ran April through August outside the heating season, a timeframe selected to emphasize the requirement for early rather than emergency replacements. The 2014-2018 funding request is for approximately 4,000 participants. The FEU is anticipating this funding would cover 2,500-3,000 participants for the April through August program, plus funding for an additional 1,000 participants for special offers for community partnerships such as Energy Diets. The funding could also be used to fund a Deep Retrofit Champion Bonus in the Home Performance Program.

282. The Furnace Replacement Program passes the mTRC. As the FEU have submitted above, the appropriate method of determining cost-effectiveness is the use of the TRC/mTRC at the portfolio level as the Commission has consistently determined in the past. Further, the UCT of 0.90 for the Furnace Replacement Program is marginal and could be improved to 1.0 for the 2014-2018 period through a number of mechanisms such as reduced program administration costs, a review of contractor incentives, or allowing only standard efficiency furnaces to be replaced since there are greater savings achieved.

[361] Exhibit B-1-1, Appendix I, Attachment I-5.

283. The Furnace Replacement Program is the best use of funding in the Residential Program Area:

- The 2012-2013 pilot was a success. Customer surveys from the 2012 program indicated that 91% of participants and 72% of contractors rate their overall satisfaction with the program 8, 9, or 10 out of 10. The point of greatest dissatisfaction for contractors was the short length of time in market.

- Without FEU funding, there will be no government rebates in market for heating system replacements and replacement rates may return back to 4.0 percent as experienced prior to government incentive programs.

- In the 2010 CPR, Furnace Replacement provided 51% of most likely achievable energy savings potential in the Residential Sector.

- The Furnace Replacement Program provides the net benefits to British Columbians, including reducing GHG emissions, strengthened FEU relationships with contractors, distributors, retailers and trade associations, enables monitoring of installations and support of training and certification of HVAC contractors, provides a "gateway" to other savings opportunities and awareness of energy bills and therefore behavioural changes as a by-product of participation. [362]

284. There are no other programs that the FEU believe can replace this cornerstone furnace program to ensure an equitable level of funding by customer class.[363]

285. The BCSEA's concerns with the program design centered on their proposal around expanding the program for replacements for any reason.[364] As the FEU have detailed in its evidence, the FEU have designed the Furnace Replacement Program to avoid free riders by

[362] Exhibit B-11, BCUC IR 1.219.7.

[363] Exhibit B-24, BCUC IR 2.374.5.2.

[364] Exhibit C4-8, pp. 29-31.

targeting early replacement. Early replacement also leads to increased energy savings in what the FEU have referred to as "Period 1" savings, being the time between replacement under the program and when the customer would have otherwise replaced the furnace. The FEU have been unable to replicate the BCSEA's suggested cost-effectiveness results and do not believe that it takes into account free riders.[365]

286. The FEU submit that their Furnace Replacement Program is based on rigorous planning and is a significant residential program that should be approved as proposed.

H. New Programs are Part of a Cost-Effective Portfolio and are in the Public Interest

287. The 2014-2018 EEC Plan contains six new programs: the New Technologies Program, the Mechanical Insulation Pilot, the Specialized Industrial Process Technology Program, the Low-Income Space Heat Top-Up Program, the Low Income Water Heating Top-Up Program, and the Non-Profit Custom Design Program.[366] All of these new programs are part of the FEU's cost-effective portfolio of EEC activities and should be accepted.

288. An analysis of all proposed new program expenditures as a percentage of overall EEC expenditure year over year provided in the table below shows that new program expenditures range from 2.76% to 4.27% of total proposed EEC expenditures.[367]

Total Proposed budget for new programs as a percentage of total expenditure, by year						
	2014	2015	2016	2017	2018	
	2.76%	3.11%	3.57%	4.27%	4.27%	

289. Program profiles for the proposed new programs, with the exception of the New Technologies program as discussed below, have been developed and presented in the 2014-2018 EEC Plan filed in Attachment I-1 of the Application, in the format discussed for the presentation of program information by the FEU's EEC staff with previous Commission staff.

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[365] Exhibit B-46, Rebuttal Evidence (Non-PBR Issues) of FEI.

[366] Exhibit B-1-1, Appendix I, pp. 18-19.

[367] Exhibit B-24, BCUC IR 2.375.1.

These program profiles contain all the assumptions used to determine program cost-effectiveness.[368] The FEU have reviewed the 2014-2018 EEC Plan with the EECAG.[369] Further details on each of these new programs are discussed below.

(a) The Specialized Industrial Process Technology Program

290. The Specialized Industrial Process Technology Program is aimed at process heat in the manufacturing sector, and is a key element of the Industrial program area of activity. This program provides prescriptive incentives to industrial customers to encourage the implementation of specific technologies and best practices targeted at particular industrial processes using natural gas as an energy source. The FEU plan to offer the following measures:[370]

(a) Steam Distribution: This prescriptive measure, targeted at facilities using steam for industrial processes, will encourage surveys and the optimization of the steam distribution system by addressing leaks, steam traps and pipe insulation.

(b) Process Boiler System: This prescriptive measure, targeted at industrial customers using boilers for steam or hot water generation, will encourage customers to increase the efficiency of their boilers through retrofits or complete replacement.

(c) Wood Drying Process: This prescriptive measure, targeted at wood drying facilities, will provide funds towards control systems and heat recovery units to increase the efficiency of wood drying process.

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[368] Exhibit B-24, BCUC IR 2.375.3. The program profiles for EEC programs are also suited to the purposes of the report filed by Commission Staff and prepared by Navigant Consulting entitled "Review of the Efficiency Maine Trust Triennial Plan (2011-2013)"

[369] Exhibit B-24, BCUC IR 2.375.3.1.

[370] Exhibit B-11, BCUC IR 1.228.3.

291. The profile for this program is included on page 66-67 of the 2014-2018 EEC Plan.[371] As shown on p. 63 of the 2014-2018 EEC Plan, the program has a TRC of 4.66, a UCT of 7.3 and a PCT of 6.18. The FEU submit that this program is cost-effective pursuant to the DSM Regulation and that the expenditures should be accepted as in the public interest.

(b) Mechanical Insulation Pilot

292. The Mechanical Insulation project is a pilot program of limited scale, intended to establish whether or not a cost effective program based on the measure could subsequently be deployed. The pilot is for bare heating pipes, valves, and fittings in existing Multi-Unit Residential buildings provided with insulation per the building code and best industry practice.[372] The profile for this program is included on pages 58 to 59 of the 2014-2018 EEC Plan.[373] As stated in the plan profile:

> "Failure to comply with mechanical insulation building codes and best practices results in wasted or excess natural gas consumption. Mechanical insulation retrofits will include the following measures: heating pipes insulated with 1 ½" thick fiberglass; domestic hot water systems pipes 2" and larger will be insulated with 1 ½" thick fiberglass insulation; piping less than 2" will be insulated with 1" thick fiberglass insulation; all insulation will be covered with service jackets and PVC fitting covers; and valves for both the heat and hot water systems will be insulated with the same thickness as the adjoining pipes.
>
> An estimated 1,400,000 GJ could be saved annually by performing mechanical insulation retrofits and improving practices and standards on new multi-unit residential buildings."

293. The pilot was initially planned to commence in 2013, but has been delayed by the inability to conclude an agreement on terms satisfactory to the FEU with a third party contractor to deliver the project.[374] The business case developed by this contractor has been

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[371] Exhibit B-1-1, Appendix I, Attachment I-1.

[372] Exhibit B-24, BCUC IR 2.375.5.

[373] Exhibit B-1-1, Appendix I, Attachment I-1.

[374] Exhibit B-11, BCUC IR 1.227.4.

filed, but may not reflect that actual pilot, should it proceed.[375] Under the original pilot proposal the FEU planned to spend up to $60,000 per building, on three mid-sized multi-unit residential buildings, to install mechanical insulation, collect and analyze data, and produce a final report of the findings. If the pilot were to proceed based on the existing business case, the overall total TRC is estimated at 1.05, and the Utility, Participant and RIM tests at 1.69, 2.18 and 0.56, respectively.[376]

294. The existing business case has positive cost-effectiveness results, although the actual pilot may vary from this initial plan. Given that this pilot would not require a significant amount of expenditures and could provide the basis for a cost-effective commercial program, the FEU submit that it should have the flexibility to carry out the pilot over the course of the 2014-2018 PBR Period.

(c) Low-income Space Heat and Water Heating Top-Up Programs

295. The Space Heat and Water Heating low-income top-up programs will be based on the same programs in the Commercial Program Area and will encourage buildings that have significant proportions of Low Income residents to replace standard efficiency boilers and water heaters with high-efficiency boilers and water heaters. The energy savings and measure life assumptions are based on the Commercial Space Heat program, except that these low-income top-up programs will provide an incentive that is about 30% higher with the extra incentive costs coming from the Low Income Program area. The program profiles for these programs thus only show 30% of the full incremental costs and gas savings.[377] These programs have positive TRC, UCT and PCT results and as such are cost-effective pursuant to the DSM Regulation.

296. Any building that has significant proportions of Low Income residents would be eligible for the Top-Up programs. The Low Income Space Heat and Water Heating top-op programs both involve measures that are shared amongst the whole building and, as such, FEU

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[375] Exhibit B-24, BCUC IR 2.375.5 and 2.375.5.1.

[376] Exhibit B-24, BCUC IR 2.375.5.1.

[377] Exhibit B-1-1, Appendix I, Attachment I-1, pp. 78-81.

is not able to provide Low Income benefits such as those proposed in these two new programs to buildings that have a significant number of able-to-pay tenants. Mixed income buildings would still be eligible to apply to the existing Commercial Water and Space Heat programs.[378]

297. The budget requests for these programs were based on FEU's best estimate from experience working within the non-profit sector and also the participation in the Commercial Space Heat and Water Heat programs. The low income population in BC is estimated to be 10 to 20% of the total population. The participation in the Low Income Top-Up programs has been estimated at roughly 10-20% of the participation that is expected in the Commercial Space Heat and Water Heat programs.[379]

298. The FEU submit that expenditures for these cost-effective programs are in the public interest and should be accepted.

(d) Non-Profit Custom Program

299. The goal of this Non-Profit Custom Program is to identify and provide incentives for deeper energy-efficiency retrofits to low income housing providers and not-for-profit associations.[380] As described in the program profile in the 2014-2018 EEC Plan, this program will involve an energy study and will provide incentives based on the recommendations of the study. Incentives under this program will cover all of the incremental cost of the cost-effective measures. Promotional activities will include outreach to non-profit housing societies, partnerships with non-profit housing associations, and partnerships with other service organizations working within the non-profit housing sector.[381] The program has a TRC of 2.72, UCT of 2.02, and a PCT of 4.72 and as such is cost effective pursuant to the DSM regulation. The FEU submit that the expenditures for this program are therefore in the public interest and should be accepted.

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[378] Exhibit B-24, BCUC IR 2.375.6.1.

[379] Exhibit B-24, BCUC IRs 2.375.6 and 2.375.6.1.

[380] Exhibit B-1-1, Appendix I, Attachment I-1, p. 69.

[381] Exhibit B-1-1, Appendix I, Attachment I-1, p. 82-83.

(e) New Technologies Program

300. The New Technologies Program will operate in conjunction with the Innovative Technologies Program by introducing technologies that are cost effective but with initially low market penetration. Educating the trades and consumers about the potential of the new energy-saving technologies will increase market adoption.[382]

301. As explained in Section 8 of the 2014-2018 EEC Plan, this program is designed to bring forward a DSM measure for a new technology from the Innovative Technology Program Area. The four steps of the Innovative Technology Selection and Implementation Process are described in Section 8.2 of the 2014-2018 EEC Plan. The new technologies are screened in a feasibility study process, and, if they pass, a pilot project is usually developed to gather operational experience. Pilot technologies that demonstrate acceptable levels of technical performance and cost-effective energy savings are included in the applicable programs areas. The assumptions for the actual DSM measure are taken from the pilot. Actual budget expenditures for the New Technologies Program will therefore depend on whether cost-effective and feasible programs filter into the Residential program area through the Innovative Technologies program area.[383]

302. If a cost-effective, new technology measure cannot be identified, the Residential New Technology Program would not go ahead and the funding for the program would not be spent.[384] Conversely, should more cost-effective new technologies be deployed within the New Technology Program than originally budgeted, the FEU could apply to the Commission for additional EEC funding.[385]

303. The FEU submit that given any New Technology Program measure would be the result of a successful pilot from the Innovative Technology Program, expenditures to permit the

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[382] Exhibit B-1-1, Appendix I, Attachment I-1, p. 30.

[383] Exhibit B-24, BCUC IR 2.375.4.

[384] Exhibit B-24, BCUC IR 2.368.2.

[385] Exhibit B-24, BCUC IR 2.375.4.

FEU to carry out a program to support such new technologies are in the public interest and should be accepted.

I. Flexibility Required for New Programs

304. In addition to the continuation of the existing program funding transfer rules, the FEU propose that should a new program present itself over the plan period, that they be permitted to launch new programs without pre-approval from the Commission. The FEU would transfer funds within an approved Program Area from an existing program to a new program, if the new program satisfies the FEU's EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.[386]

305. This new funding transfer rule will allow the FEU to take advantage of opportunities that emerge over the course of the PBR Period that have not been identified to date or are not sufficiently developed to propose at this time. Given the 5-year PBR period, this flexibility is important to ensure that cost effective demand-side measure opportunities are developed and initiated in a timely manner. This is consistent with the Commission's acknowledgment in the 2012-2013 FEU RRA and Rates Decision that there are advantages in being able to move funds freely among approved Program Areas to meet the needs of existing or new programs.[387]

306. Program funding levels will be monitored monthly and reported on annually in the EEC Annual Report. Should actual funding levels vary significantly from budgeted levels, the FEU will advise the EECAG and seek their input.[388]

307. The FEU therefore respectfully request that the Commission approve the FEU's ability to transfer funds within an approved Program Area from an existing program to a new

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[386] Exhibit B-1-1, Appendix I, pp. 19-20; Exhibit B-24, BCUC IR 2.380.1.

[387] Exhibit B-24, BCUC IR 2.380.

[388] Exhibit B-24, BCUC IR 2.375.3.2.

program, if the new program satisfies the FEU's EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

J. Integration with Other Utilities

308. BCSEA has suggested in its evidence that there is a need to integrate gas and electricity savings into program design and delivery.[389] The FEU's EEC programs, however, are already integrated with electric offerings. The FEU have reported on the integration with electric offerings over the 2009 to 2012 period in the FEU and BC Hydro MOU Report found in Appendix 1 of the 2012 Annual Report.[390] To date, collaborative projects have been successful in generating cost savings for BC Hydro and the FEU. By sharing skills and resources (e.g., marketing, communications, joint studies, consultation) the utilities have saved approximately $1,920,000 in shared incremental costs as a result of collaborative efforts. It is estimated the utilities have saved 40.35 GWh in electricity and 292,635 GJ4 in natural gas under collaborative programs. The FEU and BC Hydro have signed a new collaboration agreement for the 2012-2015 period.[391]

309. Integration with BC Hydro and FBC is reflected in the FEU's 2014-2018 EEC Plan. Each program plan lists partnerships that the FEU have for the program. A few examples are provided below.

(a) A key development in the CEO Program Area in 2012 was the growing partnerships with FBC and BC Hydro in an effort to maximize cost effectiveness and efficiency. This included cost sharing on print communications, booth displays and production items for various events and campaigns occurring in the shared service territory. In addition, steps were also taken toward increasing collaboration with BC Hydro in sharing best practices on partnership negotiations and outreach tactics. The FEU will be collaborating with BC Hydro on six

[389] Exhibit C4-8, p. 20.

[390] Exhibit B-1-1, Appendix I, Attachment I-2, 2012 Annual Report, Appendix A.

[391] Exhibit B-1-1, Appendix I, Attachment I-2, 2012 Annual Report, Appendix A.

outreach events in 2013.[392] In 2013, the CEO program area has continued to partner with FBC on several initiatives and programs ranging from print communications, to community events, and production items for both in shared services territory. FEI expects the partnerships to continue into and beyond the PBR period.[393]

(b) Within the Low Income Program Area, ECAP is a comprehensive whole-house program that the FEU conduct in partnership with BC Hydro and FBC so that opportunities for electricity and gas energy savings are addressed within a single program.[394] The FEU also partner with BC Hydro on the Energy Savings Kit program.[395]

(c) Within the Residential Program Area, the FEU's Energy Efficient Home Performance Program[396] is designed in collaboration with BC Hydro and FBC as the HERO Program, which will facilitate a whole-house comprehensive treatment of both gas and electric savings. The HERO Program will be presented to customers as a seamless operation and, where possible, province-wide offers will be available. The FEU's Furnace Replacement Program, and other stand-alone gas measures will reside within the HERO Program, along with electric DSM measures offered by BC Hydro and FBC.[397] The Deep Retrofit Champion Bonus will be a measure within the broader HERO Program.[398] The FEU are also collaborating with BC Hydro and FBC in its New Home Program.[399]

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[392] Exhibit B-1-1, Appendix I, Attachment I-1, 2014-2018 EEC Plan, p. 10.

[393] Exhibit B-23, CEC IRs 2.94.3 and 2.94.4.

[394] Exhibit B-24, BCUC IR 2.374.4.

[395] Exhibit B-1-1, Appendix I, Attachment I-1, 2014-2018 EEC Plan, p. 72.

[396] Exhibit B-1-1, Appendix I, Attachment I-1, 2014-2018 EEC Plan, p. 16.

[397] Exhibit B-50, BCSEA Rebuttal IR 1.2.2.

[398] Exhibit B-50, BCSEA Rebuttal IR 1.2.2.

[399] Exhibit B-1-1, Appendix I, Attachment I-1, 2014-2018 EEC Plan, p. 28.

(d) Pursuant to the FEU's EEC Evaluation Plan, evaluations of joint electric and gas DSM programs will be conducted as a single evaluation for the partners involved in delivering the program.[400]

310. The FEU submit that the integration of the FEU's EEC programs with both BC Hydro and FBC is growing and has already led to substantial cost reductions and energy savings.

K. Program Evaluation, Measurement and Verification

(a) Introduction

311. The FEU have filed an EEC Evaluation Plan which presents the studies and timing for the Evaluation, Measurement & Verification ("EM&V") activities for the PBR Period.[401] EM&V activities are split between evaluation activities, and measurement and verification activities. Evaluation activities are conducted to look at a program as a whole to determine its effectiveness. Measurement and Verification ("M&V") studies are conducted to assess pilot programs, demonstration projects, and custom programs.[402]

312. The EECAG participated and provided input in the development of the draft EM&V Framework.[403] Two key objectives in the Framework are:

(a) to provide assurance to both internal and external stakeholders for the continued support of DSM programs; and

(b) to ensure the FEU and ratepayers are obtaining value from their DSM investments.[404]

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[400] Exhibit B-1-1, Appendix I, Attachment I-8, p. 15.

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

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

[403] Exhibit B-11, BCUC IR 1.214.5.3.

[404] Exhibit B-24, BCUC IR 2.371.1.2.

313. The Evaluation Plan was developed to reflect program specific objectives while meeting industry standards in conducting EM&V activities. Staff assessed evaluation needs using the information available to date from existing and planned programs based on the following aspects: program objectives, years the program has been running (program life cycle), the program participant level, previous program evaluation studies, budget constraints, program targets, available resources, and the amount of data and information anticipated to be available to conduct the evaluations.[405]

314. Wherever possible, the evaluation of programs that span across the FEU's separate utility service territories will be conducted as a single evaluation in order to take advantage of evaluation cost efficiencies and incorporate consistency across service areas. Similarly, evaluations of joint electric and gas DSM programs will be conducted as a single evaluation for the partners involved in delivering the program.[406]

315. The EM&V budgets align with the FEU's EM&V Framework and general industry practice for budget spending on EM&V activities.[407] In keeping with general industry practice and in alignment with the EM&V Framework, the FEU plan EM&V budgets not to exceed 10% of overall DSM spending, and are targeting annual EM&V budgets to make up from 3 to 6% of the overall EEC portfolio spending. While the FEU's spending on EM&V appears at the low end of the range of percentage of spending on DSM activity among other utilities, this is not surprising since EM&V spending necessarily lags behind program spending, and the FEU's EEC spending has been ramping up in recent years. The FEU expect annual EM&V spending to increase over the PBR Period.[408]

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[405] Exhibit B-11, BCUC IRs 1.214.5.2 and 1.214.1.3.

[406] Exhibit B-1-1, Appendix I, Attachment I-8, p. 15.

[407] Exhibit B-24, BCUC IR 2.371.6.

[408] Exhibit B-11, BCUC IR 1.235.2; Exhibit B-24, BCUC IR 2.371.6.

(b) No Conflict

316. The FEU's EM&V activities are appropriately segregated to avoid conflict of interest situations that could arise between the development and implementation of EEC programs and the evaluation of those programs within the utility. This has been achieved by way of its organizational structure, following the principles and guidelines laid out in the EM&V Framework (including the principle of transparency) and by acting in an ethical manner in accordance with the FEU's Business Ethics Policy.[409]

317. The organizational separation by function between EEC Program staff and EEC EM&V staff is an important measure to avoid any potential conflict of interest. The evaluation activities are managed and conducted by staff who are independent from the program managers and staff responsible for designing and implementing DSM programs. EM&V staff ensure that evaluation requirements are defined at the program design stage and set evaluation requirements independent of the Program Managers for which studies may be successfully conducted. Such segregation enables the development and completion of unbiased EM&V reports, which then serve as a valuable tool for which to make enhancements and changes to future EEC program delivery. Evaluation studies are conducted on a program-by-program basis and adhere to the evaluation objectives principles in the draft EM&V Framework.[410] Further, the FEU's Internal Audit group, who report to a separate Vice President from both the EEC Program staff and the EEC Evaluations staff, reviews the EEC function annually to ensure that all controls and reporting requirements are being adhered to. The Internal Audit group's reports are included in the EEC Annual Reports for review by the Commission and EECAG and no concerns have been raised with respect to their findings.[411]

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[409] Exhibit B-11, BCUC IR 1.214.2.

[410] Exhibit B-11, BCUC IR 1.214.2; Exhibit B-1-1, Appendix 1, Attachment I-8; Exhibit B-24, BCUC IR 2.371.7.

[411] Exhibit B-24, BCUC IR 2.371.7.

318. In addition, as discussed above, the FEU have developed a comprehensive EM&V Framework to guide its EM&V activities.[412] The EM&V Framework has been developed by reviewing industry guidelines and common practices for EM&V activities. One of the FEU's evaluation principles in the EM&V Framework is that of providing transparency both internal and external to the FEU with respect to EM&V activities. External stakeholders, such as members of the EECAG may request to view final evaluation reports. The regulatory review process by which the FEU receive acceptance of their EEC expenditures provides additional transparency for external stakeholders.[413]

319. As also outlined in the EM&V Framework, the FEU's reliance on independent third party consultants to conduct the majority of the EM&V activities is a common industry practice. These consultants are selected by the EM&V staff, independently of the EEC Program Managers. They are chosen based on a combination of their relevant experience, the level of detail required for the each evaluation project, and the size of the program being evaluated in combination with the consultant's capacity and previous work history. Once selected, the consultant then develops the detailed evaluation plan based on the scope of work provided by the EM&V staff. When the plan has been approved by the EM&V staff, the consultant typically develops any necessary market research (for example with participants and with the relevant trade allies), conducts the analysis and develops a report. The independent third party consultants adhere to the industry guidelines, engineering calculations and methodologies, survey reporting analysis and the industry code of ethics for all evaluation activities conducted.[414]

320. All final evaluation reports and evaluation summaries are transparent and available to the Commission and other stakeholders upon request. All evaluation assumptions, calculations, and methodologies are documented and auditable. All results, positive or negative, are valued and will be used to provide input for future program design and

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[412] Exhibit B-1-1, Appendix I, Attachment I-8.

[413] Exhibit B-11, BCUC IR 1.214.2.

[414] Exhibit B-11, BCUC IR 1.214.2.

implementation. Indications of poorly performing programs or pilots will provide input to make improvements or may provide justification to discontinue a program.[415]

(c) Further Reviews Not Needed

321. The FEU have managed EM&V activities in a prudent manner and achieved the desired objective of EM&V activities. Any further review, such as reports by a Commission retained consultant, would place an unnecessary burden on rates. It is also not industry standard practice to conduct additional third party review of completed EM&V studies.[416]

322. As described above, the FEU's EM&V practices are reasonable, in line with other BC utilities and consistent with industry practice, guidelines and protocols. The FEU developed their EM&V framework with input from internal and external stakeholders, and utility partners. The EECAG members have not expressed any concern about the FEU's analysis of the cost-effectiveness of its EEC programs or portfolio and have not requested a third party review.[417]

323. The FEU estimate that an independent review of the draft EM&V Framework could cost between $30 thousand to $500 thousand or higher depending on the scope of work, not including the FEU's internal costs for managing such an activity.[418] The FEU submit that the additional costs for an independent expert review would add no value to customers.

L. Proposed Continuation of Financial Treatment is in the Public Interest

324. The FEU are proposing to continue the financial treatment of EEC expenditures that was approved by the Commission in the 2012-2013 RRA, which include the use of rate base and non-rate base deferral accounts to amortize EEC expenditures. The financial treatment of EEC expenditures approved in the 2012-2013 RRA Decision was designed to mitigate concerns regarding actual expenditures coming in below approved levels. Under this treatment, $15

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[415] Exhibit B-11, BCUC IR 1.214.2.1.

[416] Exhibit B-11, BCUC IR 1.214.3.

[417] Exhibit B-24, BCUC IRs 2.371.1.2 and 2.371.1.3.

[418] Exhibit B-24, BCUC IR 2.371.1.3.

million of expenditures are placed into rate base in each of 2012 and 2013, and the difference between the $15 million and actual expenditure levels up to the approved amount are not recovered through rates until the actual amounts are known. Given that factors beyond the FEU's control, such as the economy and cost of gas, continue to impact the level of EEC expenditures that will actually occur in any given year, the FEU are proposing to continue this accounting treatment over the PBR period.[419]

325. Consistent with the above, the Application includes combined FEU EEC rate base deferral account additions of $15.0 million in 2014, and for each year after through 2018, included on a net-of-tax basis, allocated amongst the FEU on an average customer basis, and amortized in rates over a ten-year period. The FEU are also seeking approval to transfer the balance accumulated in the non-rate base EEC Incentive deferral at the end of 2013 to the rate base EEC deferral account on January 1, 2014.[420]

326. FEI will also use the non-rate base EEC Incentive deferral account to continue accumulating the annual spending difference between the $15.0 million forecasted in FEU rate base up to the approved FEU annual funding envelope over the PBR Period. The FEU are seeking approval to transfer any new amounts accumulated in this account, during the PBR Period, to the applicable FEU rate base EEC deferral accounts in the following year, with amortization over 10 years commencing the year in which the balance is transferred.[421]

327. As provided in Section 60(1)(b)(ii) of the UCA, the financial treatment of DSM expenditures for British Columbia's utilities is that utilities in B.C. earn their regulated rate of return on DSM expenditures, as the Commission must have due regard to the setting of a rate

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[419] Exhibit B-1-1, Attachment I, p. 16.

[420] Exhibit B-1-1, Attachment I, p. 31. Note that FEI updated its forecast amounts for FEI's EEC rate base deferral account in the September 6th, 2013 Evidentiary Update (Exhibit B-15), and further in Exhibit B-24, BCUC IR 2.377.2.

[421] Exhibit B-1-1, Attachment I, p. 31; also see Appendix F5 for a discussion of the EEC non-rate base deferral accounts. See also Exhibit B-24, BCUC IR 2.380 for a description of the use of this account.

that "provides to the public utility … a fair and reasonable return on any expenditure made by it to reduce energy demands".

328. The following sections will discuss the issues raised with respect to continuing the current financial treatment, including the capitalization of EEC expenditures, the amortization period and need for further regulatory review.

(a) Capitalization of Expenditures and Incentives

329. Because the financial treatment of EEC activity includes a fair return on EEC expenditures which is comparable to the treatment of capital expenditures on supply side resources, there is an appropriate incentive for the FEU to pursue EEC activities. As stated by the FEU in the 2012-2013 RRA proceeding: "Earning the Companies' regulated rate of return on EEC expenditures…does put an EEC investment on the same footing as any other investment in the utility, and absent any restrictions to capital investments would encourage the utility to purchase all cost-effective EEC opportunities."[422]

330. Capitalization is the method currently used by all three British Columbia utilities currently engaged in DSM. This complies with the legislative requirements of this Province found in section 60(1)(b)(ii) of the UCA which states that in setting a rate under the Act, the Commission must "provide to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demand."[423] The FEU have not heard any concerns from either the EECAG or any other stakeholder regarding EEC organizational structure and shareholder incentive mechanisms.[424]

331. Information requests suggested the potential for alternative incentive structures. The FEU have responded to similar suggestions in the 2012-2013 RRA proceeding and the FEU's original 2008 EEC application proceeding. FEU's general understanding of the DSM incentive

[422] Exhibit B-11-1, Attachment 213.1.1, provided in response to BCUC IR 1.213.1.1.

[423] Exhibit B-24, BCUC IR 2.365.2.

[424] Exhibit B-24, BCUC IR 2.365.1.1.

mechanisms in other jurisdictions is that they have been designed to overcome the general disincentive for utilities to pursue DSM because DSM activities in those jurisdictions are not treated on an equal footing with supply side activities, and DSM in those jurisdictions will reduce the use of utility product and utility returns. The financial treatment for DSM activity approved and adopted in B.C. for the FEU and for the electric utilities addresses the disincentive to DSM expenditure found in other jurisdictions.[425]

332. Information requests posed the proposition that "the ideal solution is to tie incentives to program performance and to share program net benefits with ratepayers."[426] The FEU assume that this refers to approaches that contemplate expensing EEC expenditures and then providing an incentive to the utility based on performance targets. Such approaches would not be consistent with section 60(1)(b)(ii) of the UCA. Other disadvantages of expensing EEC expenditures include a mismatch between the persistence of costs and benefit, potential rate volatility due to variability in expenditures, and the need for other incentive mechanisms that are more difficult to administer.[427] Furthermore, DSM expenditures will contribute to reduced demand and future expansion requirements; incentive structures other than an earned return are unlikely to provide the utility with an opportunity to generate additional future earnings consistent with system expansion. As the FEU have indicated in previous proceedings, however, they are open to an incentive based proposal that adds performance based incentives in addition to the rate base treatment of EEC expenditures.[428]

333. The FEU submit that the current capitalization mechanism in place is consistent with the UCA and appropriately puts EEC investments on the same footing as any other investment in the utility. The capitalization approach is consistent with other utilities in B.C. and the FEU do not believe that creating different approaches amongst utilities would be appropriate. Further, as the current approach is functioning well and stakeholders have not

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[425] Exhibit B-11, BCUC IR 1.213.2.

[426] Exhibit B-24, BCUC IR 2.365.2.

[427] Exhibit B-11-1, Attachment 213.1.1, p. 99 of response to BCUC IR No. 1 submitted July 11, 2008.

[428] Exhibit B-11, BCUC IR 1.213.1.1 and Attachment 213.1.1 (Exhibit B-11-1).

raised concerns with the approach, there is no need to change the current financing treatment of EEC expenditures.

334. Information requests queried whether there is a need for further review of EEC organization structure and shareholder incentive mechanisms. For the reasons described above, the financial treatment of EEC framework is appropriate. The FEU do not believe these matters need to be reviewed again, given that they have recently been established and refined over the last 5 years.[429] Should the Commission wish to re-open the matter of the financial treatment of DSM, it would be preferable to develop a common approach for all utilities engaged in DSM in the Province, including the FEU, FBC, and BC Hydro.[430] It is noted that Section 7(d) of the recently issued Direction No. 7 to the British Columbia Utilities Commission[431] directs the Commission to allow BC Hydro to defer its DSM expenditures and amortize them over a 15-year period. Given this requirement and the requirement of section 60(1)(b)(ii) of the UCA to earn a return on any DSM expenditures, it would appear that any common approach in the Province would include the existing capitalization policy as previously approved by the Commission.

(b) Amortization Period

335. The FEU are proposing to retain the existing 10-year amortization period as previously approved by the Commission. In response to the directive from the 2012-2013 RRA Decision, the FEU have provided an analysis of the rate impacts of expensing EEC expenditures and amortizing over 5, 10 and 15 years.[432] Using updated EEC deferral account balances, the FEU also provided estimated EEC deferral account balances from 2012 to 2033 using 5-year, 10-year and 20-year amortization periods in response to BCUC IR 2.377.2.1.[433]

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[429] Exhibit B-11, BCUC IR 1.211.1.2.
[430] Exhibit B-24, BCUC IR 2.365.1.
[431] B.C. Reg 28/2014. OIC. 097, dated March 5, 2014.
[432] Exhibit B-1-1, Appendix I, Attachment I3.
[433] Exhibit B-24, BCUC IR 2.377.2.1.

336. The FEU summarized their conclusions from its analysis as follows:

> "As demonstrated by the results shown in the tables above, expensing EEC expenditures would result in significant rate increases for customers and should be considered an unnecessary burden on customers that can be avoided through a longer amortization term. Further, even a 5-year amortization period would produce a delivery rate increase of approximately 2 percent for FEI customers in 2014. If FEI had used a 5-year amortization period for the EEC deferral in this Application, the delivery rate impacts from this one account alone would have been a significant portion of the overall delivery rate increase requested in this Application. FEI believes the currently approved amortization period of 10 years is acceptable for the EEC deferral account, but would be amenable to a longer amortization period for the reasons provided. A longer amortization period results in steady and manageable rate increases for customers and provides the FEU with the opportunity to continue requesting EEC funding envelopes that adequately support customer energy efficiency needs."

337. While the FEU analyzed expensing EEC expenditures pursuant to the Commission's direction, expensing EEC expenditures would not allow the FEU to earn a return on its expenditures. As such, the FEU submit that expensing EEC expenditures is not permitted within the meaning of clause 60(1)(b)(ii) of the UCA and has other disadvantages as discussed above.

338. While the FEU are not proposing a change from the current 10-year amortization period, a longer amortization period would be consistent with other utilities in B.C. BC Hydro uses a 15-year amortization period and FBC has proposed a 15-year amortization period in their Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018.[434] It is noted that Section 7(d) of the recently issued Direction No. 7 to the British Columbia Utilities Commission[435] directs the use of a 15-year amortization period for BC Hydro's DSM expenditures.

339. A consideration in choosing the amortization period is its relationship to the average EEC measure lifespan. Based on the analysis described in response to BCUC IR 2.377.3,

[434] Exhibit B-24, BCUC IR 2.213.1.

[435] B.C. Reg 28/2014. OIC. 097, dated March 5, 2014.

the average measure life weighted by cost was found to be 13.0 years, while the average measure life weighted by savings was found to be 13.2 years.[436]

340. Another factor analyzed in IRs was shareholder return. Based on the assumptions and calculations shown in BCUC IR 2.377.4, the FEU shareholder equity return ranges from a total of $22.9 million from 2012 to 2033 for the 5 year amortization method, compared to a total of $60.1 million over the same period using the 20 year amortization method. The currently approved amortization period of 10 years results in an equity return of $37.1 million.[437]

341. While a concern was expressed that "carrying large regulatory assets on the balance sheet can weaken a utility's financial rating", the FEU clarified that the existence of regulatory assets on a utility's balance sheet does not, in and of itself, weaken a utility's credit rating. In the case of FEU's EEC expenditures, such risks are mitigated as FEU's EEC expenditures are generally pre-approved, included in rate base and recovered from customers.[438]

342. The FEU submit that evidence shows that the continuation of the 10-year amortization would be appropriate, as would a 15-year amortization period.

M. Administration of Funds for EEC Projects with a Thermal Energy Component

(a) Introduction

343. In the 2012-2013 RRA Decision, the Commission Panel found "that where there is a potential conflict of interest because the FEU may be providing capital or services to a project receiving the DSM or other incentive funds, there should be a neutral third party involved in the decision making process to award such funds." The Panel directed the FEU "to bring forward a proposal for mechanisms for approval and administration of funds by a neutral

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[436] Exhibit B-24, BCUC IR 2.377.3.

[437] Exhibit B-24, BCUC IR 2.377.4.

[438] Exhibit B-24, BCUC IR 2.377.1.

third party where the FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that funding." In response to this directive, the FEU engaged PWC to provide a proposal to act as a fairness advisor in cases where EEC funds are being provided to projects with a third party thermal energy component.[439]

344. In accordance with FEU's understanding of the directive from the 2012-2013 RRA, the FEU have obtained a proposal from PWC that would have PWC perform all aspects of individual project reviews, which would otherwise have been performed by FEU, as soon as a customer's intention to engage a third party thermal energy services provider has been established. Process diagrams indicating visually the tasks that PWC will perform are included in Exhibit B-1-1, Appendix I, Attachment I-4, Appendix A – Business Process Diagrams. [440]

345. Pursuant to the process outlined in the PWC proposal, the FEU would ask customers if they are or will be using a thermal energy provider. When the answer is yes, the FEU are immediately removed from the approval and administration of EEC funds, and any potential to inappropriately use such funds for the benefit of the FEU is eliminated.[441] Should it be determined that a program applicant has no third party thermal energy services component to their proposed project, the program application would not be subject to the PWC process. Depending on the individual program, such applicants may be subject to different forms of third party review, such as the reviews conducted as part of program impact evaluations.[442]

346. PWC is qualified to undertake the proposal. PWC is the "fairness advisor" to the FEU's NGT program, which is similar in function to fulfilling the Commission's directive for third party approval and administration of EEC funds associated with thermal energy projects. In the competitive bid process associated with selecting the fairness advisor to the NGT program, FEI

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[439] Exhibit B-1-1, Appendix I, Attachment I-4.

[440] Exhibit B-24, BCUC IRs 2.381.2 and 2.381.3.

[441] Exhibit B-24, BCUC IR 2.382.1.

[442] Exhibit B-19, COC IR 2.9.5.

issued an RFP, and received responses from three potential vendors. The vendors were rated on the following selection criteria: understanding and approach to scope of work; expertise (team); comprehensiveness of proposal; experience with similar work; and past performance with FEI. PWC emerged with the highest rating, and was therefore selected as vendor.[443] As shown in PWC's proposal, PWC has acted as a process and procurement advisor in a number of projects in B.C., including the Canada Line, Evergreen Line, and South Fraser Perimeter Road.[444]

347. Topics raised with respect to the PWC proposal are discussed below.

(b) The FEU Is the Appropriate First Point of Contact

348. A process option that would eliminate FEU as the first point of contact is unnecessary and not practical.[445] First, some participants apply for a rebate without having had any prior contact with FortisBC. The Efficient Boiler Program, for example, sees a considerable number of applications from multifamily customers under the guidance of their contractors. In these cases the rebate eligible measures have already been installed and, if a customer were working with a third party TES provider, the contract may already have been signed. As such it is not possible in these instances for the FEU to influence a participant's decision by providing preferential access to EEC funding.

349. It is only when, prior to any decisions being made, customers make initial inquiries seeking out clarity on program eligibility, incentives, terms and conditions, and/or application processes, does the potential to use preferential treatment in order to secure additional business for FAES exist. In order to eliminate the FEU as the first point of contact, PWC would need to screen all such inquiries, and leads before any involvement by the FEU. This would be impractical. For example, the FEU are estimating over 225 applications in the Efficient Boiler Program and 500 applications to the Residential New Homes Program in 2014. At approximately 30 minutes per application, receiving and reviewing applications represents

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[443] Exhibit B-11, BCUC IR 1.241.1; Exhibit B-24, BCUC IR 2.381.1.

[444] Exhibit B-1-1, Appendix I, Attachment I-4, p. 5.

[445] Exhibit B-24, BCUC IR 2.382.1.1.

approximately 50 days of work. Based on PWC's approximate daily rate of $1,790, this equates to an annual cost of approximately $90,000 for PWC just to receive and review applications for these two programs.[446]

350. Furthermore, there are many more points of contact between the FEU and potential EEC program participants than receiving an application. The FEU currently have four EEC Energy Solutions Managers, nine Commercial & Industrial Account managers, and fifteen new construction sales managers engaged in presenting and discussing EEC incentives with customers via a number of channels. Delivering program messaging and working with customers through all of these channels is critical to program success and PWC would need to commit a significant number of staff to perform all of these functions, if it were to entirely avoid the possibility that the FEU speak with any customer before it is definitely determined that there is no intention to contract with a TES provider. In short, eliminating the FEU as the first point of contact would result in considerable additional cost if program participation levels and a satisfactory customer experience are to be maintained.[447]

351. Moreover, the Commission's concern can be substantially addressed by directing PWC to ask any EEC applicants submitted to its review whether or not any FEU staff member indicated that the availability or size of EEC incentives was dependent upon the customer's selection of FAES or any other company as a TES provider. PWC could then report on the findings.[448]

352. Finally, having PWC or any third party act as the front line in regards to EEC programs goes beyond "approval and administration of funds", but rather represents something more akin to program administration and delivery.[449] As FEU submits below, it is

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[446] Exhibit B-24, BCUC IR 2.382.1.1.
[447] Exhibit B-24, BCUC IR 2.382.1.1.
[448] Exhibit B-24, BCUC IR 2.382.1.1.
[449] Exhibit B-24, BCUC IR 2.382.1.1.

beyond the Commission's jurisdiction to require the FEU to outsource the delivery of its programs.

(b) Need for an Annual Review

353. The PWC proposal includes a third party review of EEC grants involving TES components that have been awarded in the previous two years since inception of the program, and an annual review and reporting of EEC grants involving TES components on a go forward basis. The primary objective of these reviews will be to determine whether the awarded EEC grants are in line with established program guidelines and policies and that the award process was free of any bias or influence. An annual review is proposed so that any funds granted to a customer who was subsequently found to be a third party thermal energy services customer could be reviewed for fairness.[450]

354. Once the issues of third party review of distribution of EEC funds to projects with thermal energy components has been canvassed in this proceeding, and a decision as to how to deal with this issue arrived at, the FEU intend to ask applicants in programs that may involve a third party thermal energy services provider at the time they apply to the program, whether or not their project either has or contemplates a third party energy services provider. Thus, such an annual review may not be necessary beyond the initial year.[451]

355. The FEU analyzed options for the annual review as suggested by Commission staff. The FEU submit that the PWC proposal is the most reasonable in the circumstances and addresses the Commission's directive from the 2012-2013 RRA Decision.[452]

[450] Exhibit B-1-1, Appendix I, Attachment I-4, pp. 1 and 3.

[451] Exhibit B-24, BCUC IR 2.383.1.

[452] Exhibit B-24, BCUC IRs 2.383.5 and 2.383.6.

(c) Cost Recovery

356. The FEU have not budgeted an amount for the PWC proposal for the PBR period due to the uncertainty in the costs. PWC has estimated a range from approximately $140 thousand to $260 thousand to conduct the work and there are unknown factors that will influence the actual costs, such as the number of applications that will need to be reviewed, time for review, and the complexity of applications for review, which are beyond the FEU's control.[453]

357. If the Commission approves a third party review, the FEU requests approval to place any actual expenditures from the review in the non-rate base EEC deferral account that attracts AFUDC. This treatment is appropriate as the review would form part of the administrative costs for EEC programs, as the review is intended to ensure that EEC expenditures are dispensed appropriately. This is the same treatment applied to costs of other non-incentive administration costs for EEC. The costs of the third party review would be incremental to the FEU's existing EEC expenditure request.

358. Like other amounts in the non-rate base deferral account, the FEU would apply to transfer new amounts accumulated in the non-rate base deferral account during the 2014-2018 period to the applicable FEU rate base EEC deferral account in the following year, with amortization over 10 years commencing the year in which the balance was transferred. Under the proposed treatment, the costs of a third party review of EEC incentives for program applicants with third party thermal energy services suppliers would not result in less EEC funds available for EEC projects.[454]

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[453] Exhibit B-24, BCUC IR 2.381.4.

[454] Exhibit B-19, COC IR 2.9.11.

N. The Delivery of EEC Services by the FEU

(a) Introduction

359. In the information request process, the Commission asked about how FEI delivers EEC services, and the related topic of having a third party service provider take over responsibility for spending the FEU EEC budget.[455] FEU has two general submissions with respect to these issues.

360. First, the FEU are the appropriate entity to deliver EEC services and involves third parties when it is in the interests of customers to do so.

361. Second, the decision to outsource is one that rests with the FEU, and is a matter outside of the Commission's jurisdiction. The Commission cannot direct the FEU to outsource its EEC program.

362. Each of these submissions is discussed further in this section.

(b) The FEU is the Appropriate Entity to Deliver EEC Services to Customers

363. The FEU submit that they are the appropriate entities to deliver EEC services to customers. The FEU have been delivering EEC services for a number of years, and have developed a considerable body of experience, internal expertise, and knowledge regarding the delivery of these programs. The success of the FEU's programs to date is reflected in their annual reports, most recently the 2012 Annual Report, which have confirmed amongst other things, that the FEU's portfolio of EEC programs has been cost effective. Consultation with the EECAG has also been positive, confirming that no major course corrections are necessary.[456]

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[455] See for example Exhibit B-11, BCUC IRs 1.225.5 and 1.225.6 and Exhibit C4-13, BCUC-BCSEA 1.5.1.

[456] Exhibit B-1-1, Appendix I, Attachment I-2, 2012 Annual Report. Exhibit B-11, BCUC IRs 1.224.1 and 1.225.7.

364. The FEU involve third parties with its EEC programs when appropriate, and additionally, coordinates with other providers of energy efficiency incentive programs. For example:

(a) the Residential program area participates in bi-weekly meetings with program partners to discuss operational issues, program design opportunities, market needs, communications plans and future program planning; [457]

(b) the FEU's Conservation Education and Outreach program area corresponds frequently with FBC through email, regular phone calls and written business cases on a variety of EEC programs including school programs, partnerships, outreach and energy conservation initiatives that occur in the joint FEU and FBC service territory;[458]

(c) the FEU collaborated closely with BC Hydro on six outreach events throughout 2013 and share event evaluations and feedback, as well as discuss new partnership and outreach opportunities as they arise;[459]

(d) the FEU work with several social agencies in the delivery of Low Income programs;[460]

(e) FEU actively reviews and considers DSM project ideas from third parties as they are submitted;[461]

(f) the FEU relies on independent third party consultants to conduct the majority of its EM&V activities, consistent with common industry practice;[462] and

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[457] Exhibit B-11, BCUC 1.223.1
[458] Exhibit B-11, BCUC 1.223.1
[459] Exhibit B-11, BCUC 1.223.1
[460] Exhibit B-11, BCUC 1.225.1
[461] Exhibit B-11, BCUC 1.225.3
[462] Exhibit B-11, BCUC IR 1.214.2.

(g) one of the FEU's evaluation principles in the EM&V Framework is that of providing transparency both internal and external to the FEU with respect to EM&V activities. External stakeholders, such as members of the EECAG may request to view final evaluation reports. The regulatory review process by which the FEU receive approval for their EEC funding provides additional transparency for external stakeholders.[463]

365. The FEU submit that they are the appropriate entities to deliver EEC, and that they involve third parties in a meaningful and constructive way to ensure the effective delivery of EEC programs.

(c) The Commission does not have jurisdiction over outsourcing

366. The FEU submit that the Commission does not have jurisdiction to order the FEU to outsource its EEC program to a third party.

367. In *British Columbia Hydro and Power Authority v. British Columbia Utilities Commission*, 1996 CanLII 3048 (BC CA) ("*BC Hydro v. BCUC*"), the Court of Appeal recognized that the UCA establishes a zone of "public utility management" or "managerial discretion" that is off-limits to the Commission.[464] *BC Hydro v. BCUC* did not address the topic of outsourcing. However, the topic of outsourcing and the Commission's jurisdiction was dealt with in proceedings that related to BC Hydro's outsourcing arrangement with Accenture Inc.

368. In 2001, the provincial government and B.C. Hydro began to take steps to permit out-sourcing of B.C. Hydro's support services through an arrangement with Accenture Inc. The Office and Professional Employees' International Union's ("OPEIU") made two successive

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[463] Exhibit B-11, BCUC IR 1.214.2.

[464] *British Columbia Hydro and Power Authority v. British Columbia Utilities Commission*, 1996 CanLII 3048 (BC CA) at. 58. A copy of this case has been filed with this Submission.

applications to the Commission to hold a public hearing into the proposed out-sourcing. B.C. Hydro opposed the applications. The Commission denied both applications.[465]

369. The OPEIU brought a third similar application to the Commission, again opposed by B.C. Hydro. While it was pending, the government enacted the *Energy and Mines Statutes Amendment Act*, S.B.C. 2003, c. 1 (the "EMSAA"). Shortly thereafter, the Lieutenant Governor in Council issued an Order in Council (the "OIC") pursuant to the provisions of the EMSAA. The EMSAA and the OIC enabled B.C. Hydro to proceed with the out-sourcing arrangement and precluded further scrutiny of the arrangement by the Commission. The OPEIU's application was again dismissed by the Commission.

370. The OPEIU commenced judicial review to challenge the constitutionality of the EMSAA, and to attack the validity of the OIC on an administrative law basis. Their primary aim remained to secure a public hearing before the Commission into the out-sourcing arrangement. In the resulting decision, *Office and Professional Employees' Int'l Union et al v. B.C. Hydro et al*, 2004 BCSC 422 ("*OPEIU v. BC Hydro*"),[466] Neilson, J. held:

> "[63] Moreover, I am satisfied that neither the purpose nor the effect of the ***EMSAA*** interfered with the petitioners' right to freedom of expression. I find that the primary objective of the ***EMSAA*** was to implement a number of legislative changes in the energy and resource sectors in British Columbia. Insofar as the ***EMSAA*** dealt with B.C. Hydro, it provided the means to out-source support services, which was part of a long-term, comprehensive energy plan that had been evolving since 2001. <u>The choice to out-source these services to Accenture was a management decision. As such, it fell within the purview of B.C. Hydro's directors, and did not attract the jurisdiction of the Utilities Commission: ***British Columbia Hydro and Power Authority v. British Columbia Utilities Commission***, supra at paras. 55-58</u>.
>
> [64] The Utilities Commission itself recognized this in its decisions on the petitioners' Applications No. 1 and No. 2, prior to the enactment of the ***EMSAA***. In each decision, it considered the proposed arrangements with Accenture, and

[465] BCUC Order G-28-02, April 17, 2002.

[466] A copy of *Office and Professional Employees' Int'l Union et al v. B.C. Hydro et al*, 2004 BCSC 422 is filed with this Submission.

> found it had no jurisdiction to examine them, due to the combined operation of s. 37(x) of the ***Hydro Act***, ss. 52 and 53 of the ***UCA***, and its limited jurisdiction to intrude into the management of B.C. Hydro." [Underline added.]

371. The FEU submit that *OPEIU v. BC Hydro* establishes that the Commission does not have jurisdiction to direct a public utility to outsource a service. The choice to outsource a service is a management decision, and outside of the Commission's jurisdiction. As Neilson, J. noted at para. 64 of her reasons, the Commission has previously confirmed this point as well.

PART NINE: CONCLUSION

372. FEI submits that the evidence in this proceeding demonstrates that the approvals sought are just and reasonable and in the public interest. FEI respectfully requests that the Commission grant the approvals sought as set out in Section A2 of the Application as amended and in the Draft Order included in Exhibit B-1-5.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: April 25, 2014 ***[original signed by Christopher Bystrom]***

Christopher Bystrom
Counsel for FortisBC Energy Inc.

BOOK OF AUTHORITIES

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CA019726
Vancouver Registry

Court of Appeal for British Columbia

IN THE MATTER OF THE UTILITIES COMMISSION ACT S.B.C. 1980, C.60 AS AMENDED AND IN THE MATTER OF AN APPLICATION BY BRITISH COLUMBIA HYDRO AND POWER AUTHORITY TO AMEND ITS ELECTRIC TARIFF RATE SCHEDULES (THE "APPLICATION")

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

APPLICANT
(APPELLANT)

AND:

THE BRITISH COLUMBIA UTILITIES COMMISSION, BRITISH COLUMBIA ENERGY COALITION, CONSUMER'S ASSOCIATION OF CANADA (B.C. BRANCH) ET AL, COUNCIL OF FOREST INDUSTRIES, WEST KOOTENAY POWER LTD., B.C. GAS UTILITY LTD., ISCA MANAGEMENT LTD., and RICK BERRY

RESPONDENTS

Before: The Honourable Mr. Justice Goldie
The Honourable Madam Justice Prowse
The Honourable Madam Justice Newbury

Chris Sanderson, J. Christian and
A.M. Dobson-Mack — Counsel for the Appellant

Mark M. Moseley — Counsel for the Respondent
The British Columbia Utilities Commission

Carol Reardon — Counsel for the Respondent
Intervenor, British Columbia Energy Coalition

Michael P. Doherty — Counsel for the Respondent
Intervenor, Consumer's Association of Canada
(B.C. Branch) et al

D.W. Bursey — Counsel for the Respondent
Intervenor, Council of Forest Industries et al

Place and Date of Hearing: Vancouver, British Columbia
February 15, 1996

Place and Date of Judgment: Vancouver, British Columbia
February 23, 1996

Written Reasons by:
The Honourable Mr. Justice Goldie

Concurred in by:
The Honourable Madam Justice Prowse
The Honourable Madam Justice Newbury

Court of Appeal for British Columbia

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

v.

THE BRITISH COLUMBIA UTILITIES COMMISSION, BRITISH COLUMBIA ENERGY COALITION, CONSUMER'S ASSOCIATION OF CANADA (B.C. BRANCH) ET AL, COUNCIL OF FOREST INDUSTRIES, WEST KOOTENAY POWER LTD., B.C. GAS UTILITY LTD., ISCA MANAGEMENT LTD., and RICK BERRY

Reasons for Judgment of Mr. Justice Goldie:

1 This is an appeal, by leave, from Order G-89-94 of the British Columbia Utilities Commission (the "Commission") with reasons for the decision attached. I refer to these reasons as the "Decision" and to Order G-89-94 as the "Order".

2 After a public hearing the Commission released the Decision on 24 November 1994. Notice of an application for leave to appeal to this Court was filed by B.C. Hydro on 22 December 1994. Leave was granted 15 December 1995, the day the application was heard. The delay occurred when the Commission acceded to B.C. Hydro's application that it reconsider the Order and Decision. The reasons denying reconsideration were released on 17 October 1995. These proceedings accounted for much of the delay between the filing of the notice of application for leave to appeal and the granting of leave.

3 The issue, as stated by the appellant British Columbia Hydro and Power Authority ("B.C. Hydro"), is whether the Commission exceeded its jurisdiction in respect of certain directions in the Decision given the force of a Commission order. While it is common ground the standard of review in respect of jurisdiction is that the Commission must be correct in its interpretation of its constituent statute, the respondents contend the Commission acted within its jurisdiction and the appeal should be dismissed as no palpable and overriding error has been demonstrated that would permit this Court's intervention.

Background - General

4 B.C. Hydro is a publicly owned utility generating, transmitting and distributing electrical energy. With few exceptions its service area is province wide. Its rates are subject to approval by the Commission under the provisions of the ***Utilities Commission Act***, S.B.C. 1980, c. 60 as amended (the "***Utilities Act***"). Under s.3.1 of the ***Utilities Act*** the Lieutenant Governor in Council may issue a direction to the Commission specifying the factors, criteria and guidelines the Commission is to observe in respect of B.C. Hydro. Such a direction, Special Direction No. 8, was in force at the time material to this appeal.

5 By virtue of the ***Hydro and Power Authority Act***, R.S.B.C. 1979, c. 188 as amended (the "***Authority Act***"), B.C. Hydro is for all its purposes an agent of the Queen in Right of the Province; is deemed to have been granted an energy operation certificate for the purposes of the ***Utilities Act*** in respect of its works existing on 11 September 1980; and is not bound by any statute or statutory provision of the Province except what is made applicable to it by Order in Council. The Minister of Finance is its fiscal agent. The ***Utilities Act*** is among those ordered to be applicable to B.C. Hydro except sections dealing with one aspect of reserve funds; one enforcement provision and those requiring Commission approval of security issues and property disposition.

6 Section 5 of the ***Authority Act*** provides that the directors of B.C. Hydro, appointed by the Lieutenant Governor in Council, shall manage its affairs. The powers of B.C. Hydro include the generation, manufacture, distribution and supply of power and the development of power sites and power plants. The exercise of these powers is subject to the approval of the Lieutenant Governor in Council. A further distinction between B.C. Hydro and investor-owned utilities is that B.C. Hydro's sole "shareholder" and not its directors determines when and in what amounts "dividends" will be paid.

7 Under s-s.4 of s.141 of the ***Utilities Act***, which came into force 11 September 1980, the rates of B.C. Hydro then in effect became its lawful, enforceable and collectible rates.

8 Prior to 30 June 1995 Part 2 of the ***Utilities Act*** provided an approval process of generating and transmission facilities by the Lieutenant Governor in Council which could, at the latter's discretion, bypass the Commission. In this event the Commission might be called upon to approve rates reflecting the capital costs of large scale projects without the opportunity to pass upon the adequacy of the information justifying the construction of such projects as contemplated by the requirement under s.51(1) of the ***Utilities Act*** requiring a certificate of public convenience and necessity prior to embarking upon construction. This provision is of some importance and I set it out here:

> **51.** (1) Except as otherwise provided, no person shall, after this section comes into force, begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

9 This prospect has been removed by amendments, primarily to Part 2 of the ***Utilities Act***, and with it any justification for concern over multi million dollar additions to the property devoted to public service without prior regulatory scrutiny.

Background - "Integrated Resource Plan Guidelines"

In February, 1993 the Commission issued a 12-page document, to which I will refer as the "Guidelines", entitled "Integrated Resource Planning ("IRP") Guidelines". The following is the Definition section of the Guidelines:

> **II DEFINITION**
>
> IRP is a utility planning process which requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand[1]. The process results in the selection of that mix of resources which yields the preferred[2] outcome of expected impacts and risks for society over the long run. The IRP process plays a role in defining and assessing costs, as these can be expected to include not just costs and benefits as they appear in the market but also other monetizable and non-monetizable social and environmental effects. The IRP process is associated with efforts to augment traditional regulatory review of completed utility plans with cooperative mechanisms of consensus seeking in the preparation and evaluation of utility plans. The IRP process also provides a framework that helps to focus public hearings on utility rates and energy project applications.
>
> 1 Referred to as Demand-Side Management (DSM)
>
> 2 The term "preferred" is chosen to imply that society has used some process to elicit social preferences in selecting among energy resource options. Unfortunately, there is rarely agreement on the best process for eliciting social preferences. Candidate processes in a democracy include public ownership with direction from cabinet or a ministry, regulation by a public tribunal, referendum, and various alternate dispute resolution methods (e.g. consensus seeking stakeholder collaboratives).

11 In the Purpose section the Commission stated the Guidelines were:

> ... intended to provide general guidance regarding BCUC expectations of the process and methods utilities follow in developing an IRP. It is expected that the general rather than detailed nature of the proposed guidelines will allow utilities to formulate plans which reflect their specific circumstances.

12 The Commission's identification of the objectives of this process was stated in these words:

> 1. Identification of the objectives of the plan
>
> Objectives include but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; consideration of environmental impacts; consideration of other social principles of ratemaking[3], coherency with government regulations and stated policies.

Footnote 3 provides in part:

> ... The general implication is that because of social and environmental objectives, the rates charged by utilities may be allowed to diverge from those that would result from a rate determination based exclusively on financial least cost. The social principles to be addressed may be identified by the utility, intervenors, or government.

13 In Part III of the Guidelines defining the relationship between regulated utilities and the Commission under the Integrated Resource Plan Process the following sentences occur:

> IRP does not change the fundamental regulatory relationship between the utilities and the BCUC. Thus IRP guidelines issued by the BCUC do not mandate a specific outcome to the planning process nor do they mandate specific investment decisions. ... Under IRP,

> utility management continues to have full responsibility for making decisions and for accepting the consequences of those decisions. ... Consistency with IRP guidelines and the filed IRP plan will be an additional factor that the BCUC will consider in judging the prudency of investments and rate applications, although inconsistency may be warranted by changed circumstances or new evidence.

14 We are not called upon to determine whether the Guidelines, as defined above, are an appropriate exercise of the Commission's regulatory powers under the *Utilities Act* nor is there an appeal from any part of the Order disposing of B.C. Hydro's application to vary its rates.

15 What is objected to is the manner in which the Commission has purported to give the Guidelines the force of a Commission order. It is convenient at this point to set out the substantive part of Order G-89-94:

> **NOW THEREFORE** the Commission, for reasons stated in the Decision, orders as follows;
>
> 1. The applied for 2.8 percent increase in rates is denied and the interim increase authorized by Order No. G-18-94 effective April 1, 1994 is to be refunded, with interest calculated at the average prime rate of the principal bank with which B.C. Hydro conducts its business. B.C. Hydro is to provide the Commission with a detailed reconciliation schedule verifying the refund.
>
> 2. Rate design changes required by the Decision are to be implemented.
>
> 3. An Integrated Resource Plan and Action Plan are to be filed for approval by June 30, 1995.

4. The Commission will accept, subject to timely filing by B.C. Hydro, amended Electric Tariff Rate Schedules which conform to the terms of the Commission's Decision. B.C. Hydro will provide all customers, by way of an information notice and media publication, with the Executive Summary of the Commission's Decision.

4.(sic) B.C. Hydro will comply with all other directions contained in the Decision accompanying this Order.

(emphasis added)

16 I shall refer to the directions identified in the last paragraph as the "Directions". And it is paragraph 4 (sic) of the Order that is in issue here. Counsel for B.C. Hydro says there are 15 Directions related to the Guidelines covered by this paragraph.

17 The principal relief sought, as stated in B.C. Hydro's factum, includes a declaration "... that the IRP related aspects of Order G-89-94 and of the November Decision are void and of no effect".

18 In my view, the Direction best illustrating the issue raised by B.C. Hydro is that which requires it to establish what is called a collaborative committee (the "Committee") together with those Directions determining the part this Committee is to play in B.C. Hydro's performance of its statutory obligation under s.44 of the ***Utilities Act*** to provide service to the public.

Discussion

19 Mr. Moseley on behalf of the Commission asserted it was doing no more than obtaining information it was entitled to, in a format it could by law determine, all at a time it was authorized to stipulate.

20 There can be little doubt, from the nature of B.C. Hydro's business, the magnitude of financial resources required and the variety of other resources directly or indirectly committed or affected that virtually every person in the Province will have an interest in the management of that business.

21 The Direction in question follows a finding that B.C. Hydro had not complied with the Guidelines "... which require an explicit decision-making process which includes public involvement." B.C. Hydro had in place a public consultation program but this was considered inadequate as being "after the fact" rather than participatory in the planning process. The membership of the Committee was determined by the Commission, apparently on the principle that the planning process is enhanced by the participation of interest groups. This appears from the following observation in the Decision:

> Determination of the appropriate trade-offs between resources requires that the values the public attaches to these costs and benefits must be determined and factored into the decision in an explicit and transparent way.

> The Commission has made it clear that such values are best determined through the direct participation of representative interest groups.
>
> Exclusive reliance on the B.C. Hydro staff, managers and Board of Directors for resource selection is also unacceptable for another reason. A closed, in-house process has the appearance of, and real potential for, bias in decision making that favors the interests of the bureaucracy within the Utility.

The Committee as constituted following the Order and Decision consisted of two representatives of B.C. Hydro and 11 representing a variety of interests. Each of the 11 spoke for his or her group. Some were regional, others represented classes of customers. One or two represented people who wished to do business with B.C. Hydro.

22 Seven Directions state in detail what B.C. Hydro is to provide the Committee. One includes the following:

> Finally, the Commission directs B.C. Hydro to institute with the IRP consultative committee a multi-attribute trade-off analysis for the purposes of portfolio development and selection.

This process is defined in the Commission's glossary of terms:

> **Multi-Attribute Analysis** - A method which allows for comparison of options in terms of all attributes which are of relevance to the decision maker(s). In IRP, common attributes are financial cost, environmental impact, social impact and risk.

23 This requires B.C. Hydro to appraise future projects which it may never implement because of, for instance, financial constraints

imposed by the Minister of Finance or by virtue of a special direction under s.3.1 of the ***Utilities Act***.

24 There is evidence supporting the following assertion in the appellant's factum:

> The bulk of the IRP Directives can be characterized as requiring BCH to put BCH's resource planning initiatives and analyses to the Consultative Committee and be guided by the views and information provided by the members of the Consultative Committee in undertaking its resource planning responsibilities.

25 It cannot be seriously questioned that the Commission requires compliance with its Guidelines: at p.66 of the reasons the Commission concludes a direction denying recovery of a portion of B.C. Hydro's Resource Planning Unit expenditures with these words:

> Should the Utility continue to fail to implement the Commission's directions respecting IRP, the Commission will consider the circumstances and may invoke its powers under Part 9 of the Act.

26 Part 9 of the ***Utilities Act***, to which I will later refer, includes a list of offences under the ***Utilities Act***.

27 B.C. Hydro filed with the Commission on 8 November 1996 what it called its integrated electricity plan which it asserted complied with the Directions in the Decision. The Commission has ordered a public hearing into the integrated electricity plan in February 1996.

28 I restate the question before us. It is whether there is statutory authority for the Commission's imposition of the Guidelines to the extent required by the relevant Directions in the Decision on what is essentially an internal process for which the directors of B.C. Hydro have the ultimate responsibility, both in respect of the process and for the selection of the product of the process.

29 Mr. Sanderson's first point on behalf of B.C. Hydro is that nowhere in the ***Utilities Act*** is reference made to planning. In answer, Mr. Mosely referred us to s.51(3) which requires a public utility to file annually with the Commission a statement in a prescribed form "... of the extensions to its facilities that it plans to construct". This describes a result at the conclusion of the relevant planning process. In the context of s.51(2) it refers to the construction of facilities for which separate certificates of public convenience and necessity may not be required.

30 In my view, s.51(3) has little relevance to the case at bar. It appears B.C. Hydro routinely files the statement referred to. The amounts in question may be in the aggregate substantial but one would expect many of the expenditures for individual components would not be, as they would relate to the routine reinforcement of transformation and distribution facilities required to meet load growth or to maintain the reliability and adequacy of service.

31 Section 28 of the *Utilities Act* is also relied upon by the respondents. In full, it provides:

> **General supervision of public utilities**
>
> **28.** (1) The commission has general supervision of all public utilities and may make orders about equipment, appliances, safety devices, extension of works or systems, filing of rate schedules, reporting and other matters it considers necessary or advisable for the safety, convenience or service of the public or for the proper carrying out of this Act or of a contract, charter or franchise involving use of public property or rights.
> (2) Subject to this Act, the commission may make regulations requiring a public utility to conduct its operations in a way that does not unnecessarily interfere with, or cause unnecessary damage or inconvenience to, the public.

32 Two observations can be made of this section: the first is that the class of matters referred to in s-s.(1) relates to the existing service provided the public as distinct from future service. The second is that s-s.(2) also refers to present service, that is to say, the conduct of operations in relation to the public. Neither of these subsections refers to the utility's plans for the future.

33 Section 29 of the *Utilities Act* has some relevance to the contention that the IRP process comprises in one bundle the exercise of individual powers granted the Commission. It directs the Commission to make examinations and conduct inquiries necessary to keep itself informed about, amongst other things, the conduct of

public utility business. It does not authorize the Commission to direct how that business is conducted.

34 The Commission is supplied with B.C. Hydro's load forecasts as is apparent from its comments in the Decision. These dictate the response a utility must make to meet its statutory obligation to provide service as well as to maintain compliance with the terms of existing certificates of public convenience and necessity. It is within this part of the process that the Commission has decided, in its words, to make the IRP the "... driving force behind the establishment of a utility action plan approved by senior management."

35 It appears reasonable to assume the purpose of the Guidelines is to look beyond a simplistic view of utility planning as one limited to selecting the resources needed to meet anticipated demand and in doing so, to reject an equally simplistic view of regulation as ensuring that service is provided at the least cost to the consumer. It has been evident for some years now that environmental considerations are important in the formulation of the opinion represented by the phrase "public convenience and necessity". To the same effect, conservation and management of energy use is now recognized in what is known as demand side management. The wisdom of all this does not appear to be an issue.

36 The Commission's order directs when and how these factors are to be taken into account in the sequence of B.C. Hydro's planning processes.

37 The Commission in its factum asserts the IRP process is designed to accomplish two objectives:

1. It provides information to the Commission as to the resource selection choice being made by a utility; and
2. Following a review of the IRP plan for the Commission "... it provides guidance to utility management in the form of an advance indication as to the approach the Commission is likely to apply when it subsequently assesses the prudency of the expenditures made by the utility."

38 It will be noted the first objective refers to choices being made while the second refers to expenditures already made.

39 This dichotomy between present planning and past expenditures is said by the Commission to require regulatory control at the planning stage to avoid the dilemma of disallowing substantial incurred expenditures at the rate review stage. The examples given by the Commission in its reconsideration reasons were a nuclear plant and a large hydro electric dam.

40 Section 51 of the ***Utilities Act*** avoids this Hobson's choice. It does so by requiring a certificate of public convenience and necessity before the utility begins construction. It is not suggested the Commission has been demonstrably ineffectual in discharging its responsibilities at the certification stage.

41 Other provisions in the Act relied upon by the Commission are as follows:

1. Section 49 which requires a utility to furnish information to the Commission and answer its questions. This does not require that the utility create information for the purpose of a consultative committee nor to respond to the requests of a consultative committee - both of which have been directed by the Commission.
2. Sections 64-66 which deal with the Commission's jurisdiction over rates. To the extent these are relevant I have dealt with them in my comment on s.51 of the ***Utilities Act***.

42 I am of the view no section of the ***Utilities Act*** expressly enables the Commission to impose by order its chosen form of controlling planning at the stage selected by it.

43 In this I rely upon the literal meaning of each of the sections in the Act which have appeared to me to have any relevant significance.

44 These are, however, to be construed in relation to the ***Utilities Act*** as a whole. I refer to what Mr. Justice Beetz said in ***UES, Local 298 v. Bibeault***, [1988] 2 S.C.R. 1048 at 1088 as the initial stage in a pragmatic or functional analysis:

> At this stage, the Court examines not only the wording of the enactment conferring jurisdiction on the administrative tribunal, but the purpose of the statute creating the tribunal, the reason for its existence, the area of expertise of its members and the nature of the problem before the tribunal.

45 The premise of such an analysis is that it focuses on jurisdiction: did the legislature intend the question in issue to be answered by the courts or by the tribunal? It is a matter of statutory interpretation with the emphasis on purpose.

46 In this light the ***Utilities Act*** is a current example of the means adopted in North America, firstly in the United States, to achieve a balance in the public interest between monopoly, where monopoly is accepted as necessary, and protection to the consumer provided by competition. The grant of monopoly through certification of public convenience and necessity was accompanied by the correlative

burden on the monopoly of supplying service at approved rates to all within the area from which competition was excluded.

47 It is self-evident this process cannot be undertaken on a day to day basis by legislature or government. Hence, the creation of public utilities commissions. In the United States a constitutionally acceptable formula was evolved to protect the grantee of a certificate of public convenience and necessity from rates so low they constituted piece-meal confiscation of property without due compensation. The form this took was adopted in Canada. A brief historical sketch, relevant to this province, is found in the concurring judgment of Mr. Justice Locke in ***British Columbia Electric Railway Co. Ltd. v. The Public Utilities Commission***, [1960] S.C.R. 837 at 842-845. The ***Utilities Act*** contains many expressions linking it with its legislative antecedents.

48 The certification process is at the heart of the regulatory function delegated to the Commission by the legislature. In ***Memorial Gardens Association Ltd. v. Colwood Cemetery Co.***, [1958] S.C.R. 353 Mr. Justice Abbott, after referring to the American origin of the phrase, said at 357:

> As this Court held in the *Union Gas* case, *supra*, the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative

> discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission.

49 The other function the legislature has entrusted to the regulatory tribunal is the supervision of the utility's use of property dedicated to service as a result of the certification process. Unless so certified, or exempted from certification by the Commission, such property is not part of the appraised value of the utility company under s.62(1) which is the basis for fixing a rate under s.66. In respect of such property the supervisory powers of the Commission, principally found in Part 3 of the ***Utilities Act***, enable it to oversee the statutory obligation in s.44 to furnish service imposed upon every public utility, namely:

> **44.** Every public utility shall maintain its property and equipment in a condition to enable it to furnish, and it shall furnish, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

50 It is not without some significance that the Commission found in the Decision the following:

> From the evidence, the Commission recognizes that B.C. Hydro is generally maintaining a safe, secure and highly reliable generation, transmission and distribution service. Given this high level of reliability, the Commission has focused on cost control as an issue at this time.

51 The ***Utilities Act*** runs to over 140 sections. The administration of the jurisdiction conferred upon the Commission is amply delineated by express terms. There is no need to imply terms for this purpose.

52 I have already described the reason for the existence of the tribunal. The expertise or skills of its members vary. Experience has demonstrated skills associated with accounting, economics, finance and engineering have been frequently utilized. Unlike labour relations tribunals where past experience in the field of labour relations is a virtual prerequisite, past experience in the regulatory field is not necessary. A similar observation may be made with respect to securities commissions. Both labour relations tribunals and securities commissions are expressly conferred with policy making powers. None such are conferred on the Commission.

53 In considering the nature of the problem before the tribunal I will first deal with the ***Utilities Act*** as a law of general application. I will then consider whether the provisions of the ***Utilities Act*** which relate only to B.C. Hydro affect my conclusions.

54 I earlier referred to the characterization of the issue. Counsel for the Commission contended it merely related to the enforcement of the information gathering power conferred on the Commission.

55 I am unable to agree with that characterization as in my opinion the IRP process is specific to the planning phase of the utility's response to its statutory obligations and its enforcement by order is an exercise of management as it relates neither to the certification process as such nor to the supervision of the utility's use of its property devoted to the provision of service.

56 It is only under s.112 of the ***Utilities Act*** that the Commission is authorized to assume the management of a public utility. Otherwise the management of a public utility remains the responsibility of those who by statute or the incorporating instruments are charged with that responsibility.

57 One of the primary responsibilities and functions of the directors of a corporation is the formulation of plans for its future. In the case of a public utility these plans must of necessity extend many years into the future and be constantly revised to meet changing conditions. In the case at bar the effect of the Commission's directions is to place a group, whose interests are disparate, in a superior position in the sequence of planning and to require the directors to justify a deviation from the product of the IRP process in the exercise of their responsibilities.

58 Taken as a whole the ***Utilities Act***, viewed in the purposive sense required, does not reflect any intention on the part of the legislature to confer upon the Commission a jurisdiction so to determine, punishable on default by sanctions, the manner in which the directors of a public utility manage its affairs.

59 When the ***Utilities Act*** is examined in light of the provisions applicable to B.C. Hydro alone, this conclusion is reinforced. I have mentioned s.3.1. This authorizes the Lieutenant Governor in Council to issue a direction to the Commission specifying "factors, criteria and guidelines" to be used or not used by the Commission in regulating and fixing rates for B.C. Hydro. There is no comparable mandatory power conferred on the Commission to issue such directions to B.C. Hydro. From my examination of the ***Utilities Act*** this is the only reference to guidelines. A further important exclusion from the jurisdiction of the Commission is its approval of the issue of securities under s.57. Moreover, under s.59 B.C. Hydro may dispose of its property without obtaining the Commission's approval.

60 I have mentioned sanctions and the Commission's threat to resort to Part 9 of the ***Utilities Act***. Part 9 lists as an offence on the part of individual officers, directors and managers of utility in the failure to comply with a Commission order.

61 Tested in terms of general principles I am of the view the observations of the Ontario Court of Appeal in ***Ainsley Financial Corporation et al v. Ontario Securities Commission et al*** (1994), 21 O.R. (3d) 104, (Ont.C.A.) are relevant. In that case the Ontario Securities Commission ("OSC") issued a draft policy statement, subsequently adopted with minor modifications after the action in question had been commenced.

62 This policy statement purported to be a guide to those engaged in the marketing and selling of penny stocks as to business practices the OSC regarded as appropriate. As was set out in greater detail in ***Pezim v. British Columbia (Superintendent of Brokers)***, [1994] 2 S.C.R. 557, major securities commissions such as the OSC have a policy role in the regulation of capital markets in the public interest as well as an adjudicative function in applying sanctions in specific cases. The following headnote from ***Ainsley*** is, I think, relevant to the point before us.

> The validity of the policy statement turned on its proper characterization. If the statement was a non-binding statement or guideline intended to inform and guide those subject to regulation, the statement was valid and within the authority of the OSC; guidelines of this nature do not require specific statutory authority and such guidelines are not invalid merely because they regulate in the sense that they affect the conduct of those at whom they are directed. If, however, the statement imposed mandatory requirements enforceable by sanction, then the statement required statutory authority; a regulator cannot issue *de facto* laws disguised as guidelines.

63 The issue of non-mandatory guidelines is not a question before us. Here, I repeat, the Commission has explicitly purported to enforce the application of its directions with the threat of sanctions.

64 In my view, the appellant is entitled to a declaration that the Directions in the reasons for Decision for Order G-89-94 issued 24 November 1994 which ordered the application of the Integrated Resource Plan to British Columbia Hydro and Power Authority are beyond the statutory powers of the Commission and are accordingly unenforceable.

65 I would make no order as to costs.

"The Honourable Mr. Justice Goldie"

I AGREE: "The Honourable Madam Justice Prowse"

I AGREE: "The Honourable Madam Justice Newbury"

Pursuant to s.121 of the ***Utilities Commission Act***, the foregoing will be certified as the opinion of the Court to the Commission.

IN THE SUPREME COURT OF BRITISH COLUMBIA

Citation: ***Office and Professional Employees' Int'l Union et al v. B.C. Hydro et al***
2004 BCSC 422

Date: 20040330
Docket: L031815
Registry: Vancouver

Between:

Office and Professional Employees' International Union, Local 378 and Jerri New

Petitioners

And:

British Columbia Hydro and Power Authority

Respondent

And:

Attorney General of British Columbia

Respondent

Before: The Honourable Madam Justice Neilson

Reasons for Judgment

Counsel for the Petitioners	L. McGrady, Q.C., C. Foy & M. Koroneos
Counsel for the Respondent, B.C. Hydro and Power Authority	C.W. Sanderson, Q.C., R.A. Skolrood & J. McLean
Counsel for the Respondent, the Attorney General of British Columbia	G.H. Copley, Q.C.
Date and Place of Hearing:	December 15-19, 2003 Vancouver, B.C.

INTRODUCTION

[1] This petition has been brought to challenge steps taken by the government of British Columbia in early 2003 to out-source, or privatize, support services related to the business of the respondent, B.C. Hydro and Power Authority ("B.C. Hydro").

[2] B.C. Hydro is a Crown corporation under the ***Hydro and Power Authority Act***, R.S.B.C. 1996, c. 212 (the "***Hydro Act***"), and a public utility within the meaning of the ***Utilities Commission Act***, R.S.B.C. 1996, c. 473 (the ***"UCA"***). Under s. 12 of the ***Hydro Act***, B.C. Hydro is authorized to generate, manufacture, distribute, supply, and sell power. It provides electricity to over 90% of the population of the province.

[3] The petitioner, the Office and Professional Employees' International Union, Local 378 (the "OPEIU"), is a trade union certified under the ***Labour Relations Code***, R.S.B.C. 1996, c. 244. Prior to April 2003, it represented approximately 3000 members employed by B.C. Hydro.

[4] The petitioner, Jerri New, has been a B.C. Hydro employee since 1977, and the President of the OPEIU since 1999.

[5] On February 27, 2003, the provincial government proclaimed the ***Energy and Mines Statutes Amendment Act***, S.B.C.

2003, c. 1 (the "***EMSAA***"). This legislation included amendments to the ***Hydro Act*** and the ***UCA*** that permitted the completion of an out-sourcing arrangement negotiated between B.C. Hydro and Accenture Inc. ("Accenture") with respect to B.C. Hydro support services, many of which were performed by members of the OPEIU.

[6] On March 13, 2003, the Lieutenant Governor in Council issued Order in Council No. 0219 (the "OIC"), pursuant to the ***EMSAA*** amendments to the ***Hydro Act***. The OIC formally completed the out-sourcing arrangement by designating the agreements reached between Accenture and B.C. Hydro (the "Accenture Agreements") as relating to the provision of support services. This designation had a number of ramifications, chief of which from the petitioners' perspective was limiting the role of the B.C. Utilities Commission (the "Utilities Commission") in reviewing the Accenture Agreements under the ***UCA***.

[7] The petitioners challenge the constitutionality of the ***EMSAA***, and the validity of the OIC. They seek the following relief:

a. a declaration that ss. 12(11)(a) through (e) of the ***Hydro Act***, as amended by the ***EMSAA***, is contrary to the ***Canadian Charter of Rights and Freedoms***, Part I of the ***Constitution Act, 1982***, being Schedule B to the ***Canada Act 1982***

(U.K.), 1982, c. 11 (the “***Charter***”), and is of no force and effect;

b. a declaration that the OIC purporting to designate the Accenture Agreements is illegal, *ultra vires*, void, and of no force and effect;

c. an order that B.C. Hydro disclose all relevant documents pertaining to the Accenture Agreements including, but not limited to, the complete versions of the Accenture Agreements;

d. an award of damages representing the legal and other costs and expenses incurred by the petitioners in initiating and carrying forward the applications before the Utilities Commission, and appeals, that were affected by the retroactive features of the ***EMSAA*** and the OIC; and

e. costs.

[8] The petitioners initially sought similar relief with respect to the ***Transmission Corporation Act***, S.B.C. 2003, c. 44, and a related Order in Council approved and ordered on November 22, 2003. Those aspects of the petition were adjourned during this hearing, however, pending my decision on the issues raised with respect to the ***EMSAA*** and the OIC.

THE FACTS

[9] Since 1997, the OPEIU has actively campaigned to raise public awareness about the benefits provided by public ownership of B.C. Hydro, and the negative consequences that it says will flow from the deregulation and privatization of B.C. Hydro and its services. It has hosted conferences, rallies,

and public meetings; organized informational campaigns; participated in the production of videos and CDs; placed articles and advertisements in the media; organized letter-writing to various levels of government; and lobbied and made presentations to politicians and other groups.

[10] In August 2001, the provincial government appointed the Task Force on Energy Policy to develop a long-term energy policy for the province. It was to provide recommendations with respect to all energy sectors on matters such as conservation and energy efficiency, alternative energy, electricity, oil and natural gas, coal, and regulation.

[11] A legislated B.C. Hydro rate freeze, in effect since 1996, was continued on August 27, 2001 pending this review.

[12] In October 2001, B.C. Hydro issued a Request For Expression of Interest (the “RFEI”), seeking proposals from parties in the private sector that were interested in an out-sourcing arrangement with B.C. Hydro in connection with its customer services, fleet services, and the computer services provided by its subsidiary, Westech Information Systems. B.C. Hydro received 19 proposals in response to the RFEI.

[13] On December 21, 2001, the OPEIU filed an application with the Utilities Commission, requesting a public hearing under

the ***UCA*** to examine B.C. Hydro’s proposed out-sourcing of support services (“Application No. 1”). The OPEIU alleged that the arrangement envisaged in the RFEI would violate ss. 52 and 53 of the ***UCA***, the relevant portions of which are:

> **Restraint on disposition**
>
> 52 (1) Except for a disposition of its property in the ordinary course of business, a public utility must not, without first obtaining the commission's approval,
>
> > (a) dispose of or encumber the whole or a part of its property, franchises, licences, permits, concessions, privileges or rights, or
> >
> > (b) by any means, direct or indirect, merge, amalgamate or consolidate in whole or in part its property, franchises, licences, permits, concessions, privileges or rights with those of another person.
>
> (2) The commission may give its approval under this section subject to conditions and requirements considered necessary or desirable in the public interest.
>
> **Consolidation, amalgamation and merger**
>
> 53 (1) A public utility must not consolidate, amalgamate or merge with another person
>
> > (a) unless the Lieutenant Governor in Council
> >
> > > (i) has first received from the commission a report under this section including an opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, and
> > >
> > > (ii) has, by order, consented to the consolidation, amalgamation or merger, and

> (b) except in accordance with an order made under paragraph (a).
>
> (2) The Lieutenant Governor in Council may, in an order under subsection (1) (a), include conditions and requirements that the Lieutenant Governor in Council considers necessary or advisable.
>
> (3) An application for consent of the Lieutenant Governor in Council under subsection (1) must be made to the commission by the public utility.
>
> (4) The commission must inquire into the application and may for that purpose hold a hearing.
>
> (5) On conclusion of its inquiry, the commission must,
>
> (a) if it is of the opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, submit its report and findings to the Lieutenant Governor in Council, or
>
> (b) dismiss the application. ...

[14] The OPEIU also asked the Utilities Commission to review the proposed transaction pursuant to its general jurisdiction to regulate public utilities in the public interest, under Part 3 of the ***UCA***. It argued that the sale of portions of B.C. Hydro as contemplated under the RFEI would be detrimental to all consumers of electricity in the province.

[15] On March 15, 2002, the Task Force on Energy Policy produced its final report, *Strategic Considerations for a New British Columbia Energy Policy*.

[16] In April 2002, B.C. Hydro selected Accenture as the successful proponent in the RFEI process, and commenced negotiations of the out-sourcing arrangement with it.

[17] On April 17, 2002, the Utilities Commission denied the OPEIU’s request for a public hearing pursuant to Application No. 1. The Commission found that s. 32(7)(x) of the ***Hydro Act*** expressly precluded the application of s. 52 of the ***UCA*** to B.C. Hydro, and that s. 53 of the ***UCA*** did not apply to the joint venture/partnership type of arrangement described in the RFEI.

[18] The Commission also declined to conduct public hearings under its general jurisdiction to regulate utilities pursuant to Part 3 of the ***UCA***. It noted that in ***British Columbia Hydro and Power Authority v. British Columbia Utilities Commission*** (1996), 20 B.C.L.R. (3d) 106 (C.A.), the Court found that the ***UCA*** did not give the Utilities Commission jurisdiction to determine how the directors of a public utility should manage its affairs, or plan its future. The Commission concluded:

> Even if the disposition [proposed under the RFEI] was reviewable under Section 52 of the Act, the Commission recognizes that many of the public utilities under its jurisdiction have taken actions to outsource significant components of technology, services and customer information services. None of the public policy considerations raised by the OPEIU are considered to be within the jurisdiction of the

> Commission for review in a public hearing pursuant to the general supervisory responsibilities of the Commission.

[19] On April 19, 2002, B.C. Hydro announced it was expanding the scope of the Accenture Agreements to include out-sourcing of human resources, financial services, electricity supplies, and internal computer services.

[20] On April 29, 2002, the OPEIU filed an application for leave to appeal to the B.C. Court of Appeal from the decision of the Utilities Commission dismissing Application No. 1.

[21] On June 7, 2002, the OPEIU applied to the Utilities Commission under s. 99 of the ***UCA*** for reconsideration of its denial of Application No. 1, in part because of the proposed expansion of the services to be out-sourced ("Application No. 2"). On July 12, 2002, the Commission declined to reconsider the matter, citing essentially the same grounds which had governed its decision on Application No. 1. Its reasons read in part:

> The Commission is of the view that it does not have jurisdiction under its general supervisory powers to hold public hearings on dispositions of assets which are not covered by the Act because of the exemption from Section 52 of the Act. The Commission's powers under Part 3 of the Act to supervise and regulate public utilities continue to exist for activities not exempted from the Act. The Commission will regulate B.C. Hydro to ensure that the rates charged for energy are fair, just and reasonable, and that

> B.C. Hydro provides safe, adequate and secure service to its customers. This ability will exist even if B.C. Hydro contracts out significant services to third parties. B.C. Hydro acknowledges that it will remain accountable for rates and quality of services.
>
> ...
>
> In carrying out its statutory responsibilities, the Commission will continue to use its legislative powers to ensure safe, reliable services to customers at fair, just and reasonable rates. The Commission has not created a legitimate expectation that it will hold “a full investigation and public hearing of B.C. Hydro’s plans and proposals.” It has, however, provided the Union with an opportunity to be heard.

[22] On July 18, 2002, B.C. Hydro and Accenture signed a Memorandum of Understanding (the “MOU”) with respect to the out-sourcing of services. The MOU was made available to the public, with deletions of “commercially sensitive material”. Under the MOU, the activities and resources of the affected services were to be acquired by a private entity that would then provide the services to B.C. Hydro under a service agreement. B.C. Hydro was to initially have a minority position in the private entity, and then relinquish this following a transitional period.

[23] The employment circumstances of about 1500 OPEIU members, who were employees of B.C. Hydro, were potentially affected by the out-sourcing. The MOU thus triggered s. 54 of the ***Labour***

Relations Code, which required development of an adjustment plan for these employees. B.C. Hydro, Accenture, and the OPEIU commenced negotiation of an employee transition plan to govern the terms on which the employees would transfer their employment to Accenture, or consider other options under their collective agreement. A transition agreement was ultimately reached, and ratified by the OPEIU membership in late 2002.

[24] On September 30, 2002, the petitioners decided to abandon their application for leave to appeal the Utilities Commission's dismissal of Application No. 1.

[25] On November 25, 2002, the provincial Ministry of Energy and Mines published an energy policy plan, *Energy For Our Future: A Plan for B.C.* It built on the work done by the earlier Task Force, and proposed a number of changes to the energy sector of the province, including but not limited to B.C. Hydro. The plan identified four "cornerstones": low electricity rates and public ownership of B.C. Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility and no nuclear power sources.

[26] On December 19, 2002, the OPEIU filed a new application with the Utilities Commission ("Application No. 3"). It asked the Commission to consider the applicability of ss. 52, 53,

and Part 3 of the ***UCA*** to the MOU, and to hold public hearings into the repercussions of the out-sourcing proposed in the MOU. It also asked for an order restraining B.C. Hydro from taking any further steps to carry out the MOU until the public hearings were complete, and for an order for disclosure of all documents and information associated with the MOU.

[27] On January 22, 2003, Mr. Richard Neufeld, the Minister of Energy and Mines, wrote to a representative of the "Save B.C. Hydro Petition" stating that B.C. Hydro would release the cost benefit analysis of the out-sourcing when its arrangements with Accenture were complete. He also advised that "once the deal is finalized, it will need to be approved by B.C. Hydro's Board and will be reviewed by the [Utilities Commission]".

[28] On January 31, 2003, B.C. Hydro provided its response to Application No. 3. This included a statement that the application should be dismissed because it was based on "mere speculation" as to what B.C. Hydro might do.

[29] On February 24, 2003 the ***EMSAA*** was introduced. It received second reading on February 25, 2003, and was proclaimed on February 27, 2003. The ***EMSAA*** included amendments to several statutes governing the energy sector in British Columbia. Those relevant to B.C. Hydro were set out

in ss. 2 and 25 of the ***EMSAA***, and provided the basis for implementation of the out-sourcing of support services. Section 2 expanded B.C. Hydro's statutory powers under s. 12 of the ***Hydro Act*** by adding the following subsections to that section:

> (9) The Lieutenant Governor in Council, by order, may designate any agreement entered into or to be entered into by the authority that the Lieutenant Governor in Council considers relates to the provision of support services to or on behalf of the authority.
>
> (10) For the purposes of subsection (9), "**support services**" means services that support or are ancillary to the activities of the authority from time to time, and includes services related to metering for, billing and collecting fees, charges, tariffs, rates and other compensation for electricity sold, delivered or provided by the authority, but does not include the production, generation, storage, transmission, sale, delivery or provision of electricity.
>
> (11) Despite the common law and the provisions of this or any other enactment, if an agreement is designated under subsection (9),
>
>> (a) the authority is deemed to have, and to have always had, the power and capacity to enter into the agreement,
>>
>> (b) the agreement and all actions of the authority taken in accordance with the provisions of the agreement are authorized, valid and deemed to be required for the public convenience and necessity,
>>
>> (c) the authority is deemed to have, and to have always had, the power and capacity to carry out all of the obligations imposed under, and to exercise all of the rights, powers and

privileges granted by, the agreement according to its terms,

(d) the agreement is binding on and enforceable by the authority, according to the agreement's terms, and

(e) subject to subsection (12), the authority is not required to obtain any approval, authorization, permit or order under the *Utilities Commission Act* in connection with the agreement or any actions taken in accordance with the terms of the agreement, and the commission must not prohibit the authority from taking any action that the authority is entitled or required to take under the terms of the agreement.

(12) Nothing in subsection (11) (e) precludes the commission from considering the costs incurred, or to be incurred, in relation to an agreement designated under subsection (9) when establishing the revenue requirements and setting the rates of the authority.

(13) Subsections (3) and (5) do not apply to any partnership created by, under or in furtherance of an agreement designated under subsection (9).

[30] Section 25 of the ***EMSAA*** amended the definition of “public utility” in the ***UCA*** to specifically exclude:

(g) a person, other than the authority, who enters into or is created by, under or in furtherance of an agreement designated under section 12(9) of the *Hydro and Power Authority Act*, in respect of anything done, owned or operated under or in relation to that agreement.

[31] On February 28, 2003, B.C. Hydro and Accenture entered a formal agreement by which Accenture agreed to provide services

to B.C. Hydro for a 10-year term, commencing April 1, 2003. Their arrangement consisted of eight agreements: an Amended and Restated Limited Partnership Agreement, a Master Transfer Agreement, a Master Services Agreement, a Guarantee by Accenture, a Marketing Alliance Agreement, a Master Consulting Services Agreement, an Asset Conveyance Agreement, and a Support Services Agreement (collectively referred to as the "Accenture Agreements"). All but the Master Consulting Services Agreement had been executed by the parties on January 31, 2003. The Master Consulting Services Agreement had been executed on May 30, 2001.

[32] The Accenture Agreements are voluminous. They were posted on B.C. Hydro's website in early March 2003, after B.C. Hydro redacted those parts that it said contained competitive, commercial, and personally sensitive information.

[33] On March 13, 2003, the Lieutenant Governor in Council issued the OIC designating the Accenture Agreements, with the exception of the Accenture Guarantee, as being in relation "to the provision of support services to or on behalf of the authority" pursuant to the newly enacted ss. 12(9) and (10) of the ***Hydro Act***. This, in turn, triggered the application of s. 12(11). The effect of s. 12(11)(e) was to preclude scrutiny of the Accenture Agreements by the Utilities Commission under

the ***UCA***, except in the context of considering their costs pursuant to s. 12(12).

[34] The OPEIU’s Application No. 3 was the only application before the Utilities Commission at the time the OIC was issued.

[35] On April 1, 2003, about 1,300 B.C. Hydro employees who were members of the OPEIU were transferred to Accenture in connection with the out-sourcing of services. Another 200 employees and members chose other options available under the earlier transition agreement. A number of the OPEIU members expressed concern about these changes, and their potential effect on future employment security and pensions.

[36] On June 5, 2003, the Utilities Commission denied the OPEIU’s Application No. 3. In its reasons, the Commission indicated it had reviewed unredacted copies of the Accenture Agreements, and it set out a brief summary of the nature of each agreement. The Commission then stated that the amendments to s. 12 of the ***Hydro Act*** in the ***EMSAA***, together with the OIC, limited its jurisdiction to approve or review the Accenture Agreements, or actions taken under them, except with respect to the costs incurred in relation to the agreements. The Commission indicated its intention to conduct

a review of those costs at the next B.C. Hydro revenue requirements proceeding.

[37] The Utilities Commission then went on to consider the OPEIU’s arguments, despite the limitations placed on its jurisdiction by the amendments to s. 12 and the OIC. It stated that it found no material difference between the arrangements in the Accenture Agreements, and those set out in the RFEI, which it had considered in dealing with Application No. 1. Nor did it find any material change in circumstances since its decision on Application No. 1. It reiterated its view that s. 53 of the ***UCA*** had no application to the arrangements contemplated by the Accenture Agreements, stating:

> Even if OIC 0219 had not been issued, the Commission would not have had jurisdiction to review the Accenture Agreements, except as to the extent that those agreements impact revenue requirements and the setting of the rates of B.C. Hydro.

[38] The Commission affirmed its earlier finding that s. 52 of the ***UCA*** did not apply to the out-sourcing arrangement. It also restated its view that none of the public policy considerations raised by the OPEIU fell within its jurisdiction for review in a public hearing under Part 3 of the ***UCA***.

[39] On June 26, 2003 the petitioners commenced this proceeding.

[40] On July 4, 2003 the OPEIU filed an application for leave to appeal the Utilities Commission's denial of Application No. 3 to the B.C. Court of Appeal.

[41] The provincial government has proceeded to implement other aspects of the energy policy plan published on November 25, 2002. On November 20, 2003, it proclaimed the ***B.C. Hydro Public Power Legacy and Heritage Contract Act***, S.B.C. 2003, c. 86, which prohibits B.C. Hydro from selling "protected assets". These include generation and storage assets, and equipment or facilities for the transmission or distribution of electricity.

[42] The B.C. Hydro legislated rate freeze ended in March 2003. B.C. Hydro filed a revenue requirement application with the Utilities Commission in December 2003, to commence a public hearing before the Utilities Commission in 2004 to review B.C. Hydro's revenue requirements. A further hearing into B.C. Hydro's proposed rate structure is expected in 2005.

ANALYSIS

[43] The petitioners advanced extensive and varied arguments challenging the validity of both the ***EMSAA*** and the OIC.

Having considered all of these, I believe they are best dealt with under two main headings: a constitutional challenge of s. 12(11) of the ***Hydro Act***, as enacted by s. 2 of the ***EMSAA***, and a challenge to the validity of the OIC in the context of administrative law principles. Following consideration of these, I will deal with the application for disclosure of documents.

A. The Constitutionality of Subsection 12(11) of the *Hydro Act,* as Enacted by the *EMSAA*

[44] The petitioners say that s. 12(11) of the ***Hydro Act*** is unconstitutional, as it violates their right to freedom of expression under s. 2(b) of the ***Charter***.

[45] While they challenge the validity of the entire subsection, the focus of their argument is s. 12(11)(e), which they say removed their access to the Utilities Commission as a forum for expression of their views. They argue that, once they commenced Application No. 3, they had a substantive constitutional right to express their opposition to the Accenture Agreements in a full hearing before the Utilities Commission. The enactment of s. 12(11)(e) breached that right.

[46] The petitioners say that the core of Application No. 3 is the ownership and regulation of water and the hydro-electric

power derived from it. Both are significant natural resources, and privatization of aspects of B.C. Hydro is clearly a matter of public concern. Privatization raises political, commercial, consumer, and labour issues for the members of the OPEIU, both as employees of B.C. Hydro, and as citizens of this province. They argue that the importance of these issues to them, and to the general public, mandates a liberal interpretation of the right to freedom of expression, and demands access to the Utilities Commission for a full public hearing on the import of the arrangements between B.C. Hydro and Accenture.

[47] In support of this position, the petitioners cite a number of decisions of the Supreme Court of Canada, in which that Court has characterized freedom of expression as one of the fundamental tenets of democracy, and recognized its particular importance in the context of labour relations: ***Retail, Wholesale and Department Store Union, Local 580 v. Dolphin Delivery Ltd.***, [1986] 2 S.C.R. 573 at para. 12; ***United Food and Commercial Workers, Local 1518 (U.F.C.W.) v. KMart Canada Ltd.***, [1999] 2 S.C.R. 1083 at paras. 21-27; ***Dunmore v. Ontario (Attorney General)***, [2001] 3 S.C.R. 1016 at para. 38; and ***Retail, Wholesale and Department Store Union, Local 558 v.***

Pepsi-Cola Canada Beverages (West) Ltd., [2002] 1 S.C.R. 156 at paras. 32-33.

[48] The petitioners also maintain that the rule of law should be used as an interpretive aid in determining the constitutionality of s. 12(11). While they acknowledge that the rule of law does not represent a separate constitutional right, they say it provides a shield from arbitrary and unconstitutional government action: ***Canadian Council of Churches v. Canada (Minister of Employment and Immigration)***, [1992] 1 S.C.R. 236. The petitioners characterize the removal of their right to pursue Application No. 3 before the Utilities Commission as arbitrary government action.

[49] The respondents reply that the enactment of s. 12(11) did not constitute a breach of the petitioners’ right to freedom of expression, either in law or in fact. They say that the government has no constitutional obligation to provide a particular administrative forum in which the petitioners may express their views. As well, they argue that the petitioners were not in fact deprived of a forum, as the Utilities Commission proceeded to determine Application No. 3 on its merits, despite the enactment of s. 12(11). They say that the petitioners’ real complaint is not that they were denied

access to the Utilities Commission, but that the decision of the Commission was unfavourable to them.

[50] The parties agree that the petitioners bear the onus to establish a breach of s. 2(b) of the ***Charter***. They also agree that the determination of that issue is governed by the two-step analysis set out in ***Irwin Toy Ltd. v. Quebec (Attorney General)***, [1989] 1 S.C.R. 927 at paras. 40-58.

[51] The first step is to ask whether the activity the petitioners wish to pursue is properly characterized as falling within freedom of expression. Here, the respondents concede that participating in a hearing before the Utilities Commission is expressive behaviour.

[52] The second step involves an examination of whether the purpose or effect of the government action was to restrict that expressive behaviour. The characterization of government purpose must proceed from the standpoint of the guarantee in issue. In the context of s. 2(b), identification of the purpose of the legislation involves an examination of whether the enactment was aimed to control attempts to convey a meaning, either by restricting the content of expression, or by restricting a form of expression tied to content: ***Irwin Toy Ltd.***, *supra* at para. 51.

[53] If it is found that the legislative purpose was not to control or restrict freedom of expression, the petitioners may still succeed if they demonstrate that the effect of the legislation was to restrict their free expression. In order to do so, they must establish that s. 12(11) interfered with one of the principles and values underlying s. 2(b): the pursuit of truth, participation in social and political decision-making, or diversity of individual self-fulfillment and human flourishing: ***Irwin Toy Ltd.***, *supra* at para. 53.

[54] It is on this second step that the parties part company. The petitioners say that the purpose and effect of s. 12(11) was to restrict a form of expression - a hearing before the Utilities Commission - which they sought to use as a means of participating in social and political decision-making. Its enactment was thus a breach of their right to freedom of expression, and s. 12(11) must be declared unconstitutional.

[55] I agree that s. 12(11)(e) of the ***Hydro Act*** clearly curtailed the jurisdiction of the Utilities Commission to review Application No. 3, or any aspect of the Accenture Agreements. The petitioners have failed to convince me, however, that this legislation violates their constitutional right to freedom of expression.

[56] The law is clear that the right to freedom of expression does not include a positive obligation on the government to provide the petitioners with a specific forum for, or means of, expression. In ***Haig v. Canada***, [1993] 2 S.C.R. 995, Mr. Haig complained that he was unable to vote in a constitutional referendum because he had recently moved from Ontario to Quebec. He argued that this violated his right to freedom of expression. Justice L'Heureux-Dubé, writing for the majority, stated at page 1035:

> It has not yet been decided that, in circumstances such as the present ones, a government has a constitutional obligation under s. 2(b) of the *Charter* to provide a particular platform to facilitate the exercise of freedom of expression. The traditional view, in colloquial terms, is that the freedom of expression contained in s. 2(b) prohibits gags, but does not compel the distribution of megaphones. ... [emphasis in original]

[57] She went on to find there was no constitutionally entrenched right to vote in a referendum, stating at pages 1040 to 1041:

> A referendum is a creation of legislation. Independent of the legislation giving genesis to a referendum, there is no right of participation. The right to vote in a referendum is a right accorded by statute, and the statute governs the terms and conditions of participation. The Court is being asked to find that this statutorily created platform for expression has taken on constitutional status. In my view, though a referendum is undoubtedly a platform for expression, s. 2(b) of the *Charter* does not impose upon a government, whether provincial or

> federal, any positive obligation to consult its citizens through the particular mechanism of a referendum. Nor does it confer upon all citizens the right to express their opinions in a referendum. A government is under no constitutional obligation to extend this platform of expression to anyone, let alone to everyone. A referendum as a platform of expression is, in my view, a matter of legislative policy and not of constitutional law. [emphasis in original]

[58] As pointed out by counsel for the Attorney General during his argument, one may substitute “application before the Utilities Commission” for “referendum” in that passage, and reach the same conclusion. The petitioners thus had no constitutionally entrenched right to pursue Application No. 3 before the Utilities Commission. The fact that the enactment of s. 12(11) curtailed the Commission’s jurisdiction to hear that application does not constitute a breach of the petitioners’ rights under s. 2(b) of the ***Charter***.

[59] The more recent decisions of ***Native Women’s Assn. of Canada v. Canada***, [1994] 3 S.C.R. 627, and ***Delisle v. Canada (Deputy Attorney General)***, [1999] 2 S.C.R. 989 at paras. 25-27 reinforce the view that the rights created by s. 2(b) of the ***Charter*** do not require the government to provide citizens with a particular forum in which to express their views.

[60] The petitioners argue that those cases are distinguishable, as they dealt with situations in which the

aggrieved parties were excluded from expressing their views in an existing statutory forum. Here, the impugned legislation removed the statutory forum completely, just as the petitioners were using it to express their views. In the language of Justice L'Heureux-Dubé, the petitioners say that they had a megaphone, but it was removed in mid-speech.

[61] They also argue that, in the particular circumstances of this case, the government should not be permitted to pass legislation that silences its most effective critic. They point out that in ***Haig***, *supra* at paras. 79-81, the Court acknowledged that, while freedom of expression is generally enforced by a posture of restraint, a purposive approach may reveal cases in which positive government action is necessary to make the freedom meaningful. They say that this is such a case, due to the value and importance of the transaction, the significant element of public interest, and the fact that the timing of the ***EMSAA*** suggests it was directly aimed at silencing them. Their Application No. 3 was the only application pending before the Utilities Commission when s. 12(11) was enacted. They argue that the government should be compelled to permit that application to proceed before the Utilities Commission, unhampered by s. 12(11).

[62] I am unable to accept these arguments. Administrative bodies, such as the Utilities Commission, are creatures of the legislature. Periodic legislative changes to their jurisdiction and powers are inevitable, in order to reflect changing political, economic, and social objectives. Such amendments will necessarily affect the interests of parties who are engaged with the administrative body at the time. If those parties could successfully claim a constitutional right to continuation of their proceedings under the former legislation, the administrative framework of government would be paralyzed.

[63] Moreover, I am satisfied that neither the purpose nor the effect of the ***EMSAA*** interfered with the petitioners' right to freedom of expression. I find that the primary objective of the ***EMSAA*** was to implement a number of legislative changes in the energy and resource sectors in British Columbia. Insofar as the ***EMSAA*** dealt with B.C. Hydro, it provided the means to out-source support services, which was part of a long-term, comprehensive energy plan that had been evolving since 2001. The choice to out-source these services to Accenture was a management decision. As such, it fell within the purview of B.C. Hydro's directors, and did not attract the jurisdiction of the Utilities Commission: ***British Columbia Hydro and Power***

Authority v. British Columbia Utilities Commission, *supra* at paras. 55-58.

[64] The Utilities Commission itself recognized this in its decisions on the petitioners’ Applications No. 1 and No. 2, prior to the enactment of the ***EMSAA***. In each decision, it considered the proposed arrangements with Accenture, and found it had no jurisdiction to examine them, due to the combined operation of s. 37(x) of the ***Hydro Act***, ss. 52 and 53 of the ***UCA***, and its limited jurisdiction to intrude into the management of B.C. Hydro.

[65] The ***EMSAA*** amendments to s. 12 of the ***Hydro Act*** simply confirmed that the Utilities Commission was not engaged by the Accenture transaction, apart from retaining its jurisdiction to review the costs of the out-sourcing in establishing revenue requirements and setting rates.

[66] Moreover, the petitioners’ argument is significantly weakened by the fact that, despite the enactment of the ***EMSAA***, the Utilities Commission proceeded to deal with Application No. 3 on its merits, after reviewing unredacted copies of the Accenture Agreements. In its decision, the Utilities Commission acknowledged the limits imposed on its jurisdiction by s. 12(11)(e). Nevertheless, it went on to affirm its

earlier decisions saying that, even if that legislation had not been enacted, it had no jurisdiction to examine the out-sourcing arrangements covered by the Accenture Agreements.

[67] I conclude that s. 12(11) did not deprive the petitioners of a hearing before the Utilities Commission on the merits of Application No. 3.

[68] I find that the petitioners' reliance on the rule of law does not add any independent strength to their argument that s. 12(11) is unconstitutional. Nothing prevents the legislature from passing arbitrary laws, as long as they are constitutional. Thus, the petitioners' argument based on the arbitrary nature of s. 12(11) is essentially circular, and comes back to a question of its constitutionality. Protection from the passage of arbitrary legislation lies in the ballot box: ***Bacon v. Saskatchewan Crop Insurance Corp.***, [1999] 11 W.W.R. 51 (Sask. C.A.) at para. 36.

[69] The petitioners have actively pursued their right to persuade others to join them at the ballot box on the issue of privatization of B.C. Hydro. They have freely and effectively communicated their views on this matter to the public since 1997 through a variety of means, including the media, public meetings, lobbying, and informational campaigns. There is no

suggestion that the government has attempted to control the information that the petitioners seek to impart, or that it has attempted to restrict access by others to their message: ***Irwin Toy Ltd.****, supra* at para. 51.

[70] I conclude that the petitioners' application to have ss. 12(11)(a) to (e) of the ***Hydro Act***, as amended by the ***EMSAA***, declared unconstitutional, and of no force and effect must be denied.

[71] The related claim for damages must fail as well.

B. The Validity of Order in Council No. 0219

[72] The OIC was issued by the Lieutenant Governor in Council on March 13, 2003. It ordered that the Accenture Agreements were agreements related to support services, pursuant to ss. 12(9) and (10) of the amended ***Hydro Act***, which I will set out again for ease of reference:

> (9) The Lieutenant Governor in Council, by order, may designate any agreement entered into or to be entered into by the authority that the Lieutenant Governor in Council considers relates to the provision of support services to or on behalf of the authority.
>
> (10) For the purposes of subsection (9), "**support services**" means services that support or are ancillary to the activities of the authority from time to time, and includes services related to metering for, billing and collecting fees, charges, tariffs, rates and other compensation for electricity sold, delivered or provided

by the authority, but does not include the production, generation, storage, transmission, sale, delivery or provision of electricity.

[73] The effect of the designation was to trigger s. 12(11)(e), which curtails the jurisdiction of the Utilities Commission to review matters related to the designated agreements, except with respect to their costs under s. 12(12).

[74] The petitioners attack the validity of the OIC on two main grounds. First, they argue that the Lieutenant Governor in Council improperly exercised her discretion in deciding to designate the Accenture Agreements as agreements related to support services. Second, they say that she failed to observe requirements of procedural fairness in making the OIC. The ultimate objective of both arguments is to obtain a full hearing of Application No. 3 before the Utilities Commission.

[75] To properly understand and deal with the petitioners' arguments, it is necessary to first identify the precise action by the Lieutenant Governor in Council which forms the basis of their attack on the OIC.

[76] The petitioners' arguments envisage two potential sources of discretion in ss. 12(9) and (10). The first is embodied in the words "the Lieutenant Governor in Council may designate

any agreement". This pertains to her decision to act at all under s. 12(9). It is not specific to any particular agreements.

[77] The second source of discretion lies in her determination of whether particular agreements "relate to the provision of support services" as those are defined in s. 12(10). This will involve an examination of the particular agreements under consideration, in this case the Accenture Agreements.

[78] The petitioners do not assert that the Lieutenant Governor in Council wrongly exercised her discretion in the second sense. The petition does not allege that the Accenture Agreements were unrelated to the provision of support services, or that the Lieutenant Governor in Council wrongly construed them as such.

[79] Their arguments focus on the first, and more general, area of discretion. They say that the Lieutenant Governor in Council should not have exercised her discretion at all to designate any agreements by Order in Council, until the Utilities Commission had completed its hearing of Application No. 3.

[80] The petitioners' complaints are thus based to a large extent on the timing of the OIC, rather than its substance.

The Ambit for Judicial Review: Was the OIC an Administrative or Legislative Act?

[81] The first step in considering the petitioners' arguments must be a determination of the ambit for judicial review of the OIC. This will be governed to a large extent by whether the decision of the Lieutenant Governor in Council to pass the OIC is classified as a legislative or administrative act.

[82] The respondents argue that the decision to designate agreements by Order in Council under s. 12(9) is a legislative act. If they are correct, I agree that the decision of the Supreme Court of Canada in ***Canada (Attorney General) v. Inuit Tapirisat of Canada***, [1980] 2 S.C.R. 735 significantly restricts the ambit of judicial review of the OIC.

[83] In ***Inuit Tapirisat***, the Court dealt with the duty of fairness incumbent on the Governor General in Council in dealing with parties under the ***National Transportation Act***. That legislation gave a broad discretion to the Governor General in Council to vary a decision of the CRTC on petition of an interested party. The petitioners applied for such a variation, and the Governor General in Council ruled against them without fully disclosing the opposing material on which his ruling was based, and without giving them an opportunity to reply to that material.

[84] The Court affirmed that the actions of the Governor General in Council are not beyond review. The decision made it clear, however, that if the enactment of an Order in Council represents a legislative, as opposed to administrative, function, the ambit of judicial review will be significantly restricted, and requirements of procedural fairness will not apply. At page 757, the Court adopted the following statement from ***Bates v. Lord Hailsham***, [1972] 1 W.L.R. 1373 at page 1378:

> Let me accept that in the sphere of the so-called quasi-judicial the rules of natural justice run, and that in the administrative or executive field there is a general duty of fairness. Nevertheless, these considerations do not seem to me to affect the process of legislation, whether primary or delegated. Many of those affected by delegated legislation, and affected very substantially, are never consulted in the process of enacting that legislation; and yet they have no remedy ... I do not know of any implied right to be consulted or make objections, or any principle upon which the courts may enjoin the legislative process at the suit of those who contend that insufficient time for consultation and consideration has been given.

[85] At pages 758 to 759, the Court commented on the restricted role for judicial review of legislative activity generally:

> Where, however, the executive branch has been assigned a function performable in the past by the Legislature itself and where the *res* or subject matter is not an individual concern or a right unique to the petitioner or appellant, different

> considerations may be thought to arise. The fact that the function has been assigned as here to a tier of agencies (the CRTC in the first instance and the Governor in Council in the second) does not, in my view, alter the political science pathology of the case. In such a circumstance the Court must fall back upon the basic jurisdictional supervisory role and in so doing construe the statute to determine whether the Governor in Council has performed its functions within the boundary of the parliamentary grant and in accordance with the terms of the parliamentary mandate.

[86] Applying those principles here, if the Lieutenant Governor in Council acted in a legislative capacity in issuing the OIC, judicial review is limited to considering whether she acted within her statutory jurisdiction.

[87] During argument, each party referred to a number of cases in which the courts have characterized the actions of the Cabinet or individual Ministers as legislative or administrative. I find these decisions of limited assistance, as each is governed to a large extent by its particular legislative context and facts. They do, however, establish two general and related guidelines in undertaking such an analysis.

[88] The first is alluded to in the second quotation from ***Inuit Tapirisat*** above, and aptly summarized in Brown and Evans, *Judicial Review of Administrative Action in Canada*, looseleaf (Toronto: Canvasback, 1998) vol. 2 at para. 7:2330.

This is the element of generality. A government action is more likely to be legislative in nature if it is of general application, and is based on broad considerations of public policy. If the action is directed at the rights or conduct of a specific person or group, it is more likely an administrative function.

[89] The second guideline is that, in determining whether the government action is general and policy-based, or particular to certain individuals or activities, it is essential to focus on the construction and application of the particular legislative scheme.

[90] In ***Canadian Union of Public Employees v. Ontario (Minister of Labour)***, [2003] 1 S.C.R. 539 at para. 106, Justice Binnie advocated a contextual approach to statutory interpretation and incorporated the approach in E.A. Driedger, *Construction of Statutes*, 2nd ed. (Toronto: Butterworths, 1983) at page 87:

> . . . the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

I accordingly turn to a contextual analysis of the statutory framework within which the Lieutenant Governor in Council issued the OIC. That framework includes the ***Hydro Act***, the ***UCA***, and the ***EMSAA***.

[91] The ***Hydro Act*** creates B.C. Hydro, a Crown corporation. Its business includes the generation, transmission, and delivery of electricity to the vast majority of the residents of the province, under the management of a statutorily appointed board of directors. Section 3 of the ***Hydro Act*** states that B.C. Hydro is for all purposes an agent of the government. Section 12 of that ***Act*** sets out its powers, which are subject to the approval of the Lieutenant Governor in Council.

[92] B.C. Hydro is also a public utility, which by necessary implication imports concerns of public interest. Historically, the public interest has resulted in legislative regulation of public utilities for a variety of economic and social reasons, aimed at ensuring the provision of utility services to the public safely and adequately, and at reasonable rates. In British Columbia, this regulatory function is largely performed by the Utilities Commission under the ***UCA***. The legislative purpose of the scheme is reflected in s. 38 of that ***Act***, which requires public utilities to provide “a service to the public that the

commission considers is in all respects adequate, safe, efficient, just and reasonable".

[93] Part 3 of the ***UCA*** sets out the regulatory powers of the Utilities Commission. Primary among these is setting rate levels and revenue requirements that cover allowable operating costs and allowable opportunity to earn a fair rate of return. The Commission's regulatory powers over B.C. Hydro are not, however, unrestricted. Under s. 3 of the ***UCA,*** for example, the Utilities Commission must comply with any direction of the Lieutenant Governor in Council respecting its powers. Section 32(7)(x) of the ***Hydro Act*** exempts B.C. Hydro from some aspects of the Commission's oversight. As well, management of the business of B.C. Hydro is reserved to its Board, and is not the province of the Commission: ***British Columbia Hydro and Power Authority v. British Columbia Utilities Commission***, *supra*.

[94] As previously described, in 2001 the provincial government began to develop a long-term future plan for all aspects of the energy sector of the province, including B.C. Hydro. The final plan was published by the government in November 2002, and had four cornerstones, one of which was low electricity rates and public ownership of B.C. Hydro. The plan stated that this would be accomplished in part by out-

sourcing delivery of B.C. Hydro services, in the interest of reducing the cost of electricity for consumers, while maintaining quality of service.

[95] The ***EMSAA*** was enacted to introduce some of the legislative changes required to implement the government’s energy plan. Sections 2 and 25 dealt with the amendments to the ***Hydro Act*** and the ***UCA*** respectively, which were necessary to effect the out-sourcing of support services. Section 2 added ss. 12(9) to (13) to B.C. Hydro’s powers under s. 12 of the ***Hydro Act***, paving the way for the Lieutenant Governor in Council to designate the Accenture Agreements by the OIC.

[96] The effect of these amendments was to add to the Lieutenant Governor in Council’s pre-existing control over the powers of B.C. Hydro, as enumerated in s. 12 of the ***Hydro Act***. The amendments gave her the power to designate agreements as related to the provision of support services under ss. 12(9) and (10). They also set out the consequences of such a designation in ss. 12(11) and (12), which limited the jurisdiction of the Utilities Commission to cost and rate considerations, and provided B.C. Hydro with the power, capacity, and authority to enter and carry out any designated agreement. In particular, s. 12(11)(b) read:

> (11) Despite the common law and the provisions of this or any other enactment, if an agreement is designated under subsection (9) ...
>
> > (b) the agreement and all actions of the authority taken in accordance with the provisions of the agreement are authorized, valid and deemed to be required for the public convenience and necessity ... [emphasis added]

[97] In introducing the ***EMSAA*** for second reading, the Minister of Energy and Mines made the following statement with respect to the amendments concerning B.C. Hydro in British Columbia, *Official Report of Debates of the Legislative Assembly (Hansard)*, vol. 11, No. 14 (25 February 2003) at 5011 (Hon. R. Neufeld):

> The goal of the amendments to the Hydro and Power Authority Act is to obtain cost efficiencies and better service for B.C. Hydro customers. The definition of what constitutes support services for the purposes of outsourcing is clarified. By outsourcing administrative functions such as customer service, B.C. Hydro will be better focused on its core business: generating, transmitting and distributing electricity. It is these activities that generate revenues and benefits for all British Columbians.

[98] I find that a contextual construction of the statutory framework I have just reviewed leads to the inevitable conclusion that the OIC was the final step in implementing the government’s plan to out-source support services of a Crown corporation and public utility, with the object of reducing

costs and improving service for consumers. The out-sourcing was just one segment of a comprehensive scheme to reform the energy sector of the province, which had been developed on political and public policy grounds. The effects of the out-sourcing resulting from the OIC were of general application to B.C. Hydro consumers, and the citizens of the province. All of these factors strongly suggest that the decision to issue the OIC was a legislative, rather than administrative, action.

[99] The petitioners nevertheless argue that the OIC was administrative in nature, as it was directed at them specifically, and affected their individual rights in two ways. First, their Application No. 3 was the only application pending before the Utilities Commission when the OIC designated the Accenture Agreements. Thus, they alone had their hearing subverted by s. 12(11)(e). They say that they had invested a significant amount of time and money in the proceedings before the Utilities Commission. When the OIC intervened, they were deprived of the opportunity to present their concerns about the privatization of B.C. Hydro services, and its effect on the employment of OPEIU members, in a public hearing before the Commission.

[100] Second, the petitioners argue that the OIC was directed specifically at OPEIU members. Their individual

rights and interests have been significantly and detrimentally affected by the assumption of support services by Accenture, and the resulting changes to their employment. Over 1,300 of them transferred to Accenture, and over 200 took other employment options. As well, the out-sourcing of support services has led to ongoing concerns related to pension and job security for the members.

[101] I am not persuaded that these factors alter the fundamentally general and policy-based nature of the decision to issue the OIC. It is true that because of the timing of the OIC, the petitioners’ Application No. 3 was the only proceeding immediately curtailed by s. 12(11)(e). Nevertheless, the restriction on the jurisdiction of the Utilities Commission has universal application. No one may use the Commission as a forum for issues arising from the Accenture Agreements, other than in the context of rate hearings. The petitioners’ argument on this point is really directed to the timing of the OIC, and not to its classification as an administrative or legislative act.

[102] With respect to the effect of the OIC on the B.C. Hydro employees who were members of the OPEIU, the terms on which the employee transfers took place were governed by a transition plan negotiated in accordance with the ***Labour***

Relations Code. B.C. Hydro, the OPEIU, and Accenture agreed to it, and it was ratified by the membership of the OPEIU. As well, it appears to me that the real focus of the petitioners' concerns about the OPEIU members is the legislation itself, and not the decision to designate the Accenture Agreements by the OIC. Their complaint is not directed at the members' transfer to Accenture in particular, but at the power provided by s. 12(9) of the ***Hydro Act***, which permits the Lieutenant Governor in Council to designate <u>any</u> agreements to out-source support services.

[103] I accept that the individual interests of the OPEIU members will inevitably be affected by a transfer of support services, regardless of what form it takes, or with what entity the arrangements are made. I find this concern insufficient, however, to give the OIC an administrative character. It may well be the case that some individuals will be affected more than others by a legislative action, but this does not alter the legislative character of the act: ***Wells v. Newfoundland***, [1999] 3 S.C.R. 199; ***Aasland v. British Columbia (Ministry of Environment, Lands and Parks)*** (1999), 19 Admin. L.R. (3d) 154 (B.C.S.C.) at para. 28. In ***Wells***, the plaintiff's position as a senior civil servant was removed by legislation restructuring the administrative tribunal with

which he worked. He brought an action for damages, and argued that his dismissal was unfair and arbitrary. In dismissing his claim, the Court held that, as long as a legislative act falls within its constitutional bounds, its wisdom and value is subject only to review by the electorate. It stated at para. 61:

> The respondent's loss resulted from a legitimately enacted "legislative and general" decision, not an "administrative and specific" one: see *Knight*, at p. 670. While the impact on him may be singularly severe, it did not constitute a direct and intentional attack upon his interests. His position is no different in kind than that of an unhappy tax-payer who is out-of-pocket as a result of a newly enacted budget, or an impoverished welfare recipient whose benefits are reduced as a result of a legislative change in eligibility criteria. This was not a personal matter, it was a legislative policy choice.

[104] I find that the plan to out-source support services was based on considerations of general policy and public convenience. The decision of the Lieutenant Governor in Council to issue the OIC, as the last step in that process, was rooted in those same considerations. The ramifications of the OIC were of general application. I conclude the OIC was a legislative act.

Lack of Procedural Fairness

[105] The petitioners say the Lieutenant Governor in Council was bound to give them notice and an opportunity to be heard before issuing the OIC.

[106] The law is clear that the duty of procedural fairness does not apply to legislative actions of government: ***Martineau v. Matsqui Institution***, [1978] 1 S.C.R. 118; ***Cardinal v. Kent Institution***, [1985] 2 S.C.R. 643; ***Knight v. Indian Head School Division No. 19***, [1990] 1 S.C.R. 653; ***Inuit Tapirisat,*** *supra*; and ***Wells,*** *supra*.

[107] Nevertheless, the petitioners argue that classification of the OIC as a legislative act is not the end of the inquiry as to whether considerations of procedural fairness should apply. They say that Justice L'Heureux-Dubé, in ***Knight,*** *supra* at para. 24, established a tripartite analysis to determine whether a duty of fairness exists in such circumstances; the nature of the action is only the first of the three factors to be considered. The other two factors are the relationship between the government body and the individual, and the effect of the decision on the individual's rights. They say it is incumbent on the court to consider all three factors before a determination can be made as to whether

considerations of procedural fairness apply to the decision to issue the OIC.

[108] The petitioners provided no authority to support this interpretation of ***Knight***. The authorities are overwhelmingly to the contrary. Justice L'Heureux-Dubé herself, at para. 26 of ***Knight***, acknowledged that only decisions of an administrative nature attract a duty to act fairly. In my view, the finding that the decision to issue the OIC was a legislative act is fatal to the petitioners' arguments based on procedural fairness.

Legitimate Expectations

[109] The petitioners argue that they had a legitimate expectation that there would be a hearing into the Accenture arrangements before the Utilities Commission. They base this on what they say were express promises to that effect made by the Premier and by the Minister of Mines and Resources. As well, they say that the Utilities Commission had an established procedural practice of consultation, demonstrated by the fact that it previously conducted a hearing into the out-sourcing of support services by B.C. Gas.

[110] In ***Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)***, [1990] 3 S.C.R. 1170 at page 1204 the Supreme Court of

Canada discussed the principle of legitimate expectations in these terms:

> The principle developed in these cases is simply an extension of the rules of natural justice and procedural fairness. It affords a party affected by the decision of a public official an opportunity to make representations in circumstances in which there otherwise would be no such opportunity. The court supplies the omission where, based on the conduct of the public official, a party has been led to believe that his or her rights would not be affected without consultation.

[111] The Court more recently described the doctrine of legitimate expectations in ***Baker v. Canada (Minister of Citizenship and Immigration)***, [1999] 2 S.C.R. 817 at para. 26:

> The doctrine, as applied in Canada, is based on the principle that the “circumstances” affecting procedural fairness take into account the promises or regular practices of administrative decision-makers, and that it will generally be unfair for them to act in contravention of representations as to procedure, or to backtrack on substantive promises without according significant procedural rights.

[112] An expectation may legitimately arise in one of two ways: by an express promise made by a public authority responsible for the decision, or by a regular course of conduct that shows a well-defined practice of consultation: ***British Columbia and Yukon Hotels’ Assn. v. British Columbia (Liquor Distribution Branch)***, [1997] B.C.J. No. 305 (S.C.) (QL) at para. 14; and ***Sunshine Coast Parents for French v.***

Sunshine Coast School District No. 46 (1990), 49 B.C.L.R. (2d) 252 (S.C.) at 255.

[113] Because the doctrine of legitimate expectations is viewed as one aspect of procedural fairness, it is generally said that it does not apply to legislative action: ***Reference Re Canada Assistance Plan (B.C.)***, [1991] 2 S.C.R. 525 at para. 60; ***Sunshine Coast***, *supra* at 255–257; and ***Aasland***, *supra* at para. 52. I note, however, that in ***Sunshine Coast*** at page 260, Spencer J. held that legislative action may be subject to the doctrine of legitimate expectations if the legislative body has enacted procedural rules that give rise to such expectations.

[114] I am unable to find that the doctrine of legitimate expectations assists the petitioners. First, the statutory framework within which the OIC was issued contains no procedural requirements which might lead to an expectation of consultation.

[115] Second, the doctrine does not create substantive rights. Thus, even if it did apply, it would only give rise to a duty on the part of the Lieutenant Governor in Council to consult with the petitioners before issuing the OIC. It would

not provide them with a right to the hearing before the Utilities Commission which they seek.

[116] Third, I do not interpret any of the politicians' statements, which are set out in detail in Ms. New's second affidavit, as express promises that the Utilities Commission would undertake a broad public review of the arrangements made with Accenture before an Order in Council designating the agreements was made. The strongest comment was that of the Minister of Mines and Resources on January 22, 2003, when he stated that once the [Accenture] deal was finalized, it would be reviewed by the Utilities Commission. I agree with the respondents, however, that this could well refer to a review of costs by the Commission under s. 12(12) of the ***Hydro Act***, and not to the broad review sought by the petitioners.

[117] Similarly, I find that the prior practices of the Utilities Commission, including the fact that it conducted a hearing into the out-sourcing of the support services of B.C. Gas, cannot be said to have established a "well-defined practice of consultation" that would attract the doctrine of legitimate expectations, and entitle the petitioners to a public hearing with respect to the Accenture Agreements. Moreover, the decisions of the Utilities Commission on

Applications No. 1 and 2 suggest that its usual practices did not lead the petitioners to expect a public hearing before it.

[118] Finally, the doctrine applies to express promises made by the public authority responsible for the decision, in this case the Lieutenant Governor in Council. I find it difficult to understand how statements by other government representatives, or the practices of an administrative tribunal, could bind her to consult before exercising her statutory powers.

[119] I conclude that the petitioners are not able to rely on the doctrine of legitimate expectations to demonstrate that the Lieutenant Governor in Council had a duty to consult with them, or to permit a public hearing to proceed before the Utilities Commission, prior to issuing the OIC.

Improper Exercise of Discretion

[120] The petitioners say that the Lieutenant Governor in Council unreasonably exercised her discretion in passing the OIC, in that she failed to consider relevant factors, acted in bad faith, and discriminated against them.

[121] In considering these arguments, it is necessary to recall that the petition does not allege that the Accenture Agreements are unrelated to the provision of support services

as defined by s. 12(10) of the ***Hydro Act***. The attack is instead focused on the Lieutenant Governor in Council’s decision to exercise her discretion at all under s. 12(9), before Application No. 3 had been fully heard before the Utilities Commission.

[122] In determining whether the Lieutenant Governor in Council properly exercised her discretion in deciding to issue the OIC, the petitioners urge judicial review on a standard of reasonableness, determined by the pragmatic and functional approach advocated in ***Dr. Q v. College of Physicians and Surgeons of British Columbia***, [2003] 1 S.C.R. 226. They say that this review should be governed by the factors set out in ***Baker***, *supra* at paras. 53, 56: the boundaries imposed in the statute, the principles of the rule of law, the principles of administrative law, the fundamental values of Canadian society, and the principles of the ***Charter***.

[123] The difficulty that the petitioners encounter, however, is that the cases of ***Dr. Q*** and ***Baker***, as well as the numerous other authorities on which they rely, all deal with review of administrative acts. I have found that the decision to issue the OIC was a legislative act.

[124] The petitioners concede that they have found no authority to support the application of the pragmatic and functional approach to judicial review of a legislative act. They nevertheless argue that the authorities on which they rely provide a compelling inference that such an approach should guide the court in all cases of judicial review of discretionary decisions, even if they are legislative acts.

[125] I am unable to agree that the approach set out in ***Dr. Q*** lends itself to judicial review of the decision of the Lieutenant Governor in Council to perform her delegated legislative power under s. 12(9). In my view, the appropriate ambit for review of such acts remains that established in ***Inuit Tapirisat***, *supra* at pages 758-59. The court retains a "basic jurisdictional supervisory role" to determine whether the legislative action was performed in accordance with its statutory mandate. While ***Inuit Tapirisat*** was decided in the context of the duty of procedural fairness, its principles have been held to extend to the review of substantive duties: ***Re MacMillan Bloedel Ltd. and Appeal Board under the Forest Act)*** (1984), 8 D.L.R. (4th) 33 (B.C.C.A.) at paras. 12-14.

[126] The question is thus whether, in deciding to issue the OIC, the Lieutenant Governor in Council exercised her discretion within her statutory authority. The only statutory

restriction on her power to issue an Order in Council designating agreements under s. 12(9) of the ***Hydro Act*** is that the agreements be related to the provision of support services, as defined in s. 12(10).

[127] As discussed previously, the petition does not allege that the Accenture Agreements are unrelated to support services. The only argument that the petitioners advanced on this issue was that, because portions of the Accenture Agreements have been redacted, it is not possible to be sure that they relate to support services. They did not, however, point to any specific deletions in the agreements that demonstrated this uncertainty to my satisfaction.

[128] I find nothing to support a conclusion that the Lieutenant Governor in Council acted beyond her statutory authority in exercising her discretion to issue the OIC.

[129] The petitioners also argue that the Lieutenant Governor in Council acted in bad faith in exercising her discretion to enact the OIC. This allegation is based on the concurrence of the OIC and Application No. 3. The petitioners say that representatives of B.C. Hydro and the provincial government made misleading statements, inducing them to believe that the Utilities Commission would review the out-

sourcing arrangements. At the same time, those parties were taking steps to ensure that the ***EMSAA*** and the OIC were put in place as quickly as possible, specifically to preclude a public review by the Commission into the dangers of privatizing B.C. Hydro's support services.

[130] The petitioners rely on the decisions of ***Roncarelli v. Duplessis***, [1959] S.C.R. 121, and ***Markham v. Sandwich South (Township)*** (1998), 160 D.L.R. (4th) 497 (Ont. C.A.) to support their position. In particular, they cite the definition of good faith in ***Roncarelli*** at page 143:

> "Good faith" in this context, applicable both to the respondent and the general manager, means carrying out the statute according to its intent and for its purpose; it means good faith in acting with a rational appreciation of that intent and purpose and not with an improper intent and for an alien purpose; it does not mean for the purposes of punishing a person for exercising an unchallengeable right; it does not mean arbitrarily and illegally attempting to divest a citizen of an incident of his civil status.

[131] I find the present case differs in significant respects from both the ***Roncarelli*** and ***Markham*** decisions. Each of those dealt with arbitrary government action that extended well beyond the ambit of legitimate statutory authority. In each, the court found a gross abuse of legal power for ulterior motives.

[132] Here, I have found that the Lieutenant Governor in Council acted within her statutory jurisdiction in deciding to issue the OIC, and that the OIC conformed to the intent and purpose of its legislative framework. In such circumstances, there is a rebuttable presumption of regularity, that is, that the authority acted appropriately. Credible evidence is required to rebut that presumption. Suspicion and conjecture are not enough: ***Health Sciences Assn. of B.C. v. B.C. (A.G.)*** (1986), 6 B.C.L.R. (2d) 17 (S.C.) at 24; and ***Aasland***, *supra* at paras. 17, 23.

[133] While I appreciate that the timing of the events in this case leads the petitioners to suspect the *bona fides* of the Lieutenant Governor in Council, I am unable to find bad faith in the coincidence of time alone. Nor am I able to construe the statements made by other government representatives, or representatives of B.C. Hydro, as evidence of bad faith on her part.

[134] The Supreme Court of Canada in ***Thorne's Hardware Ltd. v. Canada***, [1983] 1 S.C.R. 106 clearly stated that it is not for the Court to examine the motives of government when performing legislative actions that fall within its statutory mandate. Dickson J., as he then was, stated at pages 112 to 113:

> Counsel for the appellants was critical of the failure of the Federal Court of Appeal to examine and weigh the evidence for the purpose of determining whether the Governor in Council had been motivated by improper motives in passing the impugned Order in Council. We were invited to undertake such an examination but I think that with all due respect, we must decline. It is neither our duty nor our right to investigate the motives which impelled the federal Cabinet to pass the Order in Council...
>
> I agree with the Federal Court of Appeal that the government's reasons for expanding the harbour are in the end unknown. Governments do not publish reasons for their decisions; governments may be moved by any number of political, economic, social or partisan considerations. . . .

[135] I conclude that the petitioners have failed to establish that the Lieutenant Governor in Council acted in bad faith in issuing the OIC.

[136] With respect to administrative law discrimination, the petitioners argue that the OIC had an unequal effect on them. They alone were deprived of a hearing before the Utilities Commission.

[137] I believe this argument is answered by my earlier finding that the OIC was of general application. While it is true that the petitioners’ Application No. 3 was the only matter actually pending before the Utilities Commission when the OIC was passed, the OIC nevertheless applied equally to

all who might seek a hearing before the Commission with respect to the Accenture Agreements.

[138] Moreover, the fact that a legislative act affects some individuals more than others is not by itself enough to lead to a finding of administrative law discrimination: ***Wells,*** *supra* at para. 61.

[139] I find that the petitioners have failed to establish that the Lieutenant Governor in Council exercised her discretion improperly or unreasonably in deciding to issue the OIC.

[140] I conclude that the petitioners’ attack on the OIC must fail. Their application for a declaration that the OIC is invalid is accordingly dismissed.

C. Disclosure of Documents

[141] It remains to consider the petitioners’ application for disclosure of documents. The right to production of documents in a matter proceeding by petition is extremely limited. While the court may make such an order pursuant to its inherent jurisdiction, that power is to be narrowly applied, and will only be exercised where the petitioner establishes a satisfactory evidentiary basis for the order. That is particularly so where the issue is the validity of an

Order in Council to which the presumption of regularity applies: ***Nechako Environmental Coalition v. British Columbia (Minister of Environment, Lands and Parks)*** (1997), C.E.L.R. (N.S.) 79 (B.C.S.C.).

[142] The petitioners seek production of “all relevant documents” pertaining to the Accenture Agreements. They do not particularize these documents, other than to say that they include unredacted copies of those agreements. They say the latter are relevant to the determination of whether the arrangements with Accenture are a “merger, consolidation, or amalgamation” under s. 53 of the ***UCA***, and whether the Accenture Agreements are truly agreements relating to support services as defined in s. 12(9) of the ***Hydro Act***.

[143] In my view, the characterization of the agreements in the context of s. 53 of the ***UCA*** is not relevant to the issues raised by this petition. The Utilities Commission has dealt with that question in deciding the petitioners’ Application No. 3, and in doing so declined their request for production of full copies of the Accenture Agreements. The correctness of those rulings will be dealt with by the Court of Appeal under s. 101 of the ***UCA***.

[144] The question of whether the Accenture Agreements are agreements related to the provision of support services under s. 12(9) is not raised by the petition. Production of documents for this purpose is thus not required.

[145] Even if these documents were relevant, in my view it would not be productive to order their disclosure at this stage, when the issues raised in the petition have been heard. If they were essential to those issues, an application for their production should have been brought before the hearing, as was done in ***Nechako Environmental Coalition v. British Columbia (Minister of Environment, Lands and Parks)***, *supra.*

[146] The petitioners' application for disclosure of documents is dismissed.

CONCLUSION

[147] The relief sought by the petitioners is denied. The claims in the petition that relate to the ***Transmission Corporation Act***, S.B.C. 2003, c. 44, and the related Order in Council issued on November 22, 2003, will remain outstanding. The parties may make arrangements to speak to costs if necessary.

"K. Neilson, J."
The Honourable Madam Justice K. Neilson