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September 20, 2013

Via Email
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Tannis Braithwaite, Acting Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO) Information Request (IR) No. 1

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-109-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCPSO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1.0 Reference: Exhibit B-1, Tab A, Section 1.1.1.2, page 5 and Section 2.2, page 7

Preamble: In Stage 2 of the GCOC proceeding FortisBC is requesting an increase in its equity risk premium from 40 basis points to 50 – 75 basis points above the allowed ROE for the benchmark utility FEI.

1.1 If this request were granted, would it affect FortisBC's overall allowed ROE for 2013?

Response:

The Commission's letter L1-31-13, issued on June 5, 2013, appears to have determined that the Stage 2 decision will be effective January 1, 2013. Therefore, the 2013 allowed ROE would be affected.

2.0 Reference: Exhibit B-1, Tab A, Section 1.1.1.3, pages 5-6

2.1 Do the approval conditions that the BCUC has set out in Order C-7-13 and/or the related Decision issued July 23, 2013 regarding FortisBC's AMI Application have any impact on the evidence presented in this Application or FortisBC's PBR proposals?

Response:

No, the approval conditions provided in Order C-7-13 do not impact the evidence presented in FBC's 2014-2018 RRA, including the PBR proposals.

2.2 If yes, please indicate what the impacts are and how they are linked to the Order and Decision.

Response:

Please refer to the response to BCPSO IR 1.2.1.

3.0 Reference: Exhibit B-1, Tab A, Section 3.1, page 12

3.1 How does FortisBC determine what the appropriate service levels are from the customer's perspective (per line 10)?

Response:

In general, FBC believes that the current service levels as represented by SQIs and benchmarks are appropriate for its customers and reflective of the current approved funding. As described in Appendix D6 of the Application (Exhibit B-1-1), the objective of the SQIs is to ensure that the Company continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. FBC believes the proposed SQI benchmarks, which are based primarily on the performance of the SQIs and the level of funding over the last three years, represent the appropriate service levels for customers.

3.2 In what ways are the capacity of the electric and gas businesses increased (per line 29)?

Response:

The words "increasing the capacity of both the electric and gas businesses" is in reference to a qualitative benefit of the integration efforts between the electric and gas businesses. While much of the focus on integration is typically on realizing efficiencies and cost savings, by sharing of employees and common resources, the combined FBC/FEI entities have the ability to access the broader employee knowledge base and skills of both organizations. Over time, this will contribute to improved consistency of service and flexibility in staffing.

And as noted in Exhibit B-1, sharing of employees and common resources will provide employee growth and development opportunities and contribute to a more motivated and productive workforce.

4.0 Reference: Exhibit B-1, page 13, line 36 – page 14, line 2

Preamble: On page 13, starting at line 36, FBC discusses the introduction of a shared cost allocation approach similar to that used by FEU. The BCPSO requires information to understand the proposed timing and impact of the change.

4.1 Please provide a FBC's best estimate of the timing of the change.

Response:

FBC is unable to forecast the timing of a change, if any, from the current method to a shared cost allocation approach. To the extent such a change is introduced, FBC would anticipate managing such change within the context of the approved O&M during the PBR term.

4.2 Please fully explain how any costs and benefits will be dealt with during the PBR term. As an example, would the costs and benefits be within the PBR scheme or would the costs and benefits of changes to the allocation methodology be charged to customers?

Response:

FBC clarifies that it has interpreted this question as referring specifically to costs and benefits associated with introducing the shared cost allocation approach.

Please refer to the response to BCPSO IR 1.4.3 for a discussion of the expected activities and costs associated of introducing a Shared Services cost allocation approach between FEI and FBC.

4.3 Please provide an estimate of the potential impact on costs of the change in methodology.

Response:

As indicated in the Application, FBC will continue to evaluate the feasibility of introducing a Shared Services cost allocation approach between FEI and FBC during the PBR. However, as noted, the ability to implement such an approach depends on the nature of future integration opportunities and having the necessary conditions in place for shared services such as common management, common IT platforms and common policies and processes. At this time, FortisBC does not have a specific timing for the introduction of a shared cost allocation approach.

FBC expects that O&M impacts of shared cost allocation approach would be funded within the overall O&M as provided by the PBR formula. However implementation may require investments in IT systems or other initiatives.

5.0 Reference: Exhibit B-1, Tab A, page 14

5.1 Do the planned capital expenditures for 2014-2018 (as described in Tab C, Section 5) include any spending related to the referenced "need to transition to common IT platforms" (per lines 12-13)? If yes, please identify the related spending and the anticipated common IT platform status as of 2018 (i.e. the end of the proposed PBR terms).

<u>Response:</u>

As detailed in Exhibit B-1, Tab C, p. 218 and 222, the Company will pursue productivity improvements and operational efficiencies throughout the PBR period that may result in the delivery of common IT platforms within the FortisBC utilities. This work will be accomplished primarily through the Business Technology Transformation portfolio as described in the reference. There are business areas that may identify opportunities to align both business processes and technology. These opportunities will be identified and business cased in accordance with the Project Portfolio Management process and Benefits Management practice on yearly basis tied to the budgeting cycle. High-level descriptions of these programs can be found in the reference above.

6.0 Reference: Exhibit B-1, Tab A, page 15 (lines 16-17)

Preamble: FortisBC states that "customer service has been maintained at a high level".

6.1 What evidence does FortisBC have that customers consider its recent customer service performance to be at a "high level"?

Response:

As discussed in Exhibit B-1-1 Appendix D6, the SQI results reflecting the level of service being delivered to customers have been positive. Specifically:

- Emergency response times remain higher than 90% of calls being responded to within two hours;
- Telephone service factor has remained consistent at 70% of calls answered in 30 seconds or less;
- Meter reading accuracy has been maintained at levels greater than 97%; and
- SAIDI and SAIFI results have remained positive.

Despite the high level of customer service that is reflected in these results, FBC's customer satisfaction survey has reflected the effect of customers' perceptions of and reactions to the recently implemented two-tiered Residential Conservation Rate and the proposed AMI project.

6.2 Please confirm that, at a minimum, FBC will maintain current service levels during the PBR term. If not confirmed, please fully explain.

Response:

As outlined in Appendix D-6 Service Quality Indicators, Section 2.2 Choice of Benchmarks, Exhibit B-1-1, the proposed SQI benchmarks represent the current service levels but are not to be considered as minimum thresholds to achieve. Instead, they are reference points against which levels of service quality can be compared. While FBC expects to maintain current service levels during the PBR, there may be events beyond its control that may influence service levels for some of the SQI measures. Such a circumstance would not be considered as a sustained serious degradation of service quality.

7.0 Reference: Exhibit B-1, Tab A, page 15 (lines 25-30)

7.1 What is the nature of the complaints received by FortisBC regarding the RCR?

Response:

The primary complaint received from customers with respect to the RCR is that it causes their bills to be higher than they expected. Secondary to this basic complaint are a number of related issues such as the view that the RCR:

- Is unfair to those customers who lack a viable alternative for home heating;
- Is unfair to customers with large families or otherwise lack the means to invest in conservation measures;
- Contains a threshold to which most customers cannot reasonably be expected to limit consumption; and
- Penalizes customers that have already invested in high efficiency appliances such as heat pumps.

7.2 Does FortisBC plan to utilize just the "complaints received" as input to the RCR evaluation or will it "reach out to customers" and solicit input for the evaluation?

Response:

FBC plans to solicit input from customers through the use of a random survey and will use this as well as input received during focus group sessions to further inform the customer impact section of the RCR Evaluation Report.

7.2.1 If just the former, please explain how this approach aligns with the Company's priority for "strengthening customer focus"?

Response:

Please refer to the response to BCPSO 1.7.2.

7.2.2 If the later, what specifically are FortisBC's outreach plans?

Response:

Please refer to the response to BCPSO 1.7.2. In addition, FortisBC is reaching out to customers through PowerSense initiatives such as the Energy Diets to assist customers with managing their bills. The program, which was first piloted in Rossland, will reach out to most remaining customers directly in their communities before the next heating season.

Numerous other initiatives that will help customers respond more effectively to the RCR are detailed in this application, including the Advanced Metering Infrastructure project and improved account on-line functionality.

8.0 Reference: Exhibit B-1, Tab A, page 16 (lines 33-34)

8.1 Will new self-service options only be introduced on an optional basis and if they reduce costs?

Response:

The self-service options described in the referenced section will be optional and are expected to reduce costs over time.

8.2 If yes, will FortisBC be developing business cases for each new option that demonstrate its costs/benefits prior to implementation?

Response:

FortisBC ensures through internal approval processes that expenditures such as those related to the self-service enhancements meet business requirements, including cost-effectiveness.

9.0 Reference: Exhibit B-1, Tab A, page 19

9.1 For purposes of its "Balanced Scorecard", how does FortisBC measure its regulatory performance?

Response:

Please refer to the response to BCUC IR 1.4.3.

9.2 Please provide a copy of FortisBC's actual Balanced Scorecard for the most recent year completed/reported. Please also provide any supporting documentation that provides definitions/explanations regarding the measures used.

Response:

Please refer to Attachment 9.2 showing the actual 2012 scorecard results and the explanations regarding the measures used.

10.0 Reference: Exhibit B-1, page 24, lines 7-18

Exhibit B-1-1, Appendix D1, B&V PBR Jurisdictional Report

Preamble: On lines 7-18 of page 27, FBC cites its Experts Black and Veach (B&V) that there is no preferred PBR model. The BCPSO requires information to understand if there is a preferred or best model.

10.1 Please provide B&V's opinion whether there is a best or preferred PBR model. If there is, please fully discuss and explain the preferred model.

<u>Response:</u>

B&V believes that a PBR model consists of a number of factors that relate to the particular circumstances and regulatory environment of the utility. Since there are numerous constraints on elements of the model that are external to the utility, the preferred model for each utility even in the same jurisdiction may be different (see for example the Union and Enbridge models in Ontario). B&V believes that the prior experience of FBC (and also FEI) under PBR provides guidance for and precedent for elements of a preferred model. Based on the evidence filed by the Company, the current PBR Plan is the preferred model for FBC.

10.2 Please provide FBC's opinion whether there is a best or preferred PBR model. If there is, please fully discuss and explain the preferred model.

<u>Response:</u>

FBC believes that a PBR model must suit the particular circumstances of the utility and jurisdiction. In FBC's case, it has a long standing success with PBR, and this experience provides it with the knowledge to prepare a plan that best suits the needs of the Company and its customers. Therefore the Company has used its experience with the building block approach to prepare what will be the best model for its circumstances.

10.3 Please provide a summary of all other jurisdictions in North America that B&V is aware of where a building block approach, such as proposed by FBC has been approved.

Response:

This question is similar to FEI's 2014-2018 PBR Application, BCPSO IR 1.10.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Extensive work would be required to determine which plans in other jurisdictions fit the building block approach, since each would have to be reviewed in detail to make this assessment. However FBC is aware of the following. FBC's previous PBR plans which were approved by the Commission are based on a building-block approach, meaning that the capital and operational expenditures were treated in two different blocks. The OEB's 4th Generation IR includes an option called "Custom incentive rate-setting" under which customized PBR plans such as the building-block approach are allowed. Most recently Enbridge Gas applied this option to its current PBR application and proposed a building-block approach.

The 2009 report commissioned by the European Commission and prepared by KEMA consultants indicates that in the case of European natural gas transmission operators the majority of regulators used the various forms of building-block approach (Page 44, Table 6).[1] Both Australia and New Zealand use the building block approach for both gas and electric utilities.

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1 http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/2009_12_gas_transmission_and_balancing_annex_fact_sheets.pdf

11.0 Reference: Exhibit B-1, page 27, line 33 – page 34, line 4

Preamble: In its Application, FBC discusses the "lumpiness" of capital expenditures. The proposed PBR model assumes increases in capital based on I-X. The BCPSO requires an understanding of the impact of changes in the capital budget if, if as a result of the "lumpiness", there is a material decrease in capital in a given year, and what the incentives are to minimize capital expenditures.

11.1 Please fully explain the impact on the PBR mechanism if there is a material decline in capital expenditures in a given year, and how the PBR formula will account for that.

Response:

The PBR mechanism deals with lumpiness in capital expenditures in three ways:

1. By excluding CPCN projects from the formula, which has the effect of removing 'lumpy' capital, and
2. Within the formula, the inclusion of all capital additions other than CPCN projects and flow-through items means that localized "lumpiness" is, in effect, averaged out over time. Please also refer to the response to BCPSO IR 1.11.2.
3. There is also a 10% deadband which leads to a true-up of variances outside a +- 10% range of the formula based capital expenditures as referenced in the responses to BCUC IR 1.58.1 and BCPSO IR 1.25.1.

11.2 Please fully explain how the proposed PBR model will incent reductions in capital spending.

Response:

The PBR Plan encourages FBC to seek efficiencies and find savings in the formula-based capital expenditures for the long term benefit of customers. The revenue requirement impact (or savings) arising from these reductions in capital expenditures provide a shared benefit between customers and the utility during the PBR term (and efficiency carry over period) and a long term benefit for customers after the reduced capital expenditures are rebased in rates. The incentive for FBC is in the additional earnings arising from the utility's 50% share of the benefit for a period of five years in total.

The issue of lumpiness noted in the question preamble is a reference more to large projects like CPCN projects than to projects that make up the capital spending categories included within formula-based spending allowances. Typical projects under the PBR Plan may have lumpy characteristics in a particular locale but are a part of many smaller projects that occur each year on different parts of the system based on a variety of factors. This diversity within the overall formula-based capital spending envelope allows the utility to manage spending within the I-X allowance. For example, a road widening project may require relocating the power lines in an area and reflect a change in the expected loads for that area. In that case the utility would likely upgrade the network at the same time because the area may be changing from residential to more commercial resulting in load growth. That change would result in lumpiness in the additions to distribution capacity (e.g., fast food restaurants have greater demand than residential customers). This change will not be repeated in this particular location but may occur at another location on the system in a subsequent period.

12.0 Reference: Exhibit B-1, Page 30, lines 7-10

Preamble: In lines 7-10 of page 30, FBC states:

> *PBR plans (both price cap and revenue cap) are typically further categorized into two subgroups based on their rate base assessment methodology and the role of (I–X) mechanism in forecasting their costs. These are termed the "building-block" approach and the "total expenditure" approach.*

The BCPSO requires an understanding of how the proposed PBR model is used in other jurisdictions.

12.1 Please provide a list of other jurisdictions where such a building block approach is used. In the response, please provide referenced to actual decisions and dockets where the concept was discussed and approved.

<u>Response:</u>

Please refer to the response to BCPSO IR 1.10.3.

13.0 Reference: Exhibit B-1, Page 31

Preamble: On page 31 of its Application, FBC discusses five principles of PBR. The BCPSO requires information to understand the intent and purpose of the FBC principles.

13.1 Please confirm that one of the purposes of a PBR is to break the direct link between revenues and costs. If not confirmed, please fully explain.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.1. This response is identical to the FEI response to that IR.

More precisely, the purpose of PBR is to break the link between prices and costs. The level of revenue is another matter separate and apart from the PBR Plan. As has been noted the PBR Plan must still provide a reasonable opportunity for the utility to earn the allowed return which also includes the revenue component. Failure to provide that opportunity would not result in just and reasonable rates even though PBR makes pricing independent of costs.

13.2 Please confirm that, under cost of service regulation, there is an incentive to increase rate base. If not confirmed, please fully explain.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC is aware of the economic theory that suggests that there is an incentive to increase rate base if the allowed return exceeds the market cost of capital over time. In practice, FBC does not believe this incentive exists as suggested. FBC believes that the prudence test and the used and useful test as well as competitive rate pressure all act as a clear disincentive for excess investment. Cost of service regulation in the context of FBC has led to prudent investment to expand and maintain its system.

13.3 Please confirm that one of the principles of PBR is to emulate the incentive forces that are experienced under a competitive market in order to improve efficiencies. If not confirmed, please fully explain.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.3. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

In the Alberta PBR proceeding, the AUC identified the emulation of competitive market forces, to the greatest extent possible, as a principle for their PBR Plan in AUC Decision 2012-237. Specifically, Principle 1 on page 7 of AUC Decision 2012-237 reads:

> *"A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market quote"*

FBC considers the emulation of incentive forces under competitive market conditions to improve efficiencies as more of a result of a comprehensive PBR plan than a principle. PBR effectively decouples prices from the cost of service and therefore creates the intended PBR incentives for utilities to optimize the various inputs of production to operate efficiently, similar to firms in competitive markets. However, certain regulatory safeguard mechanisms that are essential to PBR plans, (such as deferrals, SQI's and off-ramps), do not conform to competitive market behavior. Therefore, FBC believes that emulating efficiency incentives as those experienced in competitive markets, to the greatest extent possible, is implicit in a comprehensive PBR plan.

13.4 Please confirm that, under PBR, one of the intents is to provide an incentive for the utility to optimize the various inputs of production, including operating versus capital. If not confirmed, please fully explain.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.4. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

B&V provides the following response.

Theoretically, this may be the case. However, as a practical matter this cannot be confirmed. There are at least three issues that make this view incorrect as it relates to utility regulation. The first issue is the issue of sunk costs. Prior decisions that represent sunk investment in capital cannot be changed after the fact regardless of the efficiency of the decision based on current prices. In this case, there may be a more efficient combination of input resources available with current technology and prices but the implementation of that efficiency would increase not decrease costs because of the sunk costs involved in the system. The second issue is the lumpy nature of capital investment. Given the sunk cost nature of capital investments just discussed, a utility will not acquire just the current efficient level of a productive input. Instead, the utility will invest in the input based on the expected life and potential changes in the output requirements in the future related to this investment. Third, as noted above, the existence of regulation does not guarantee an efficient firm the market based cost of capital. Therefore, the efficient level of capital may not be used even under PBR. All of this contrasts with outcomes under the competitive model where there are no sunk costs, no lumpy investments and the market cost of capital is earned in equilibrium. It is for this reason that theoretical models of economics cannot be easily applied to regulated industries. In the real world certain basic assumptions do not apply. In the context of PBR, utilities are encouraged to make efficient decisions related to actions at the margin where the utility controls the decision as to all of the factors of production. This is not a global efficiency but a relative efficiency.

13.5 If sub item 4 above is confirmed, please fully explain how the FBC PBR proposal provides the incentive to FBC to optimize the various inputs of production, including operating versus capital.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.5. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Under the proposed five-year PBR plan, rates are set annually to recover the set level of expenditures prescribed by the PBR formula for the given year. Each year the component of rates designed to recover O&M and Capital expenses will adjust the previous years' amount by the PBR formula which includes a productivity factor. With the utility's prices separated from the cost to provide service, an incentive is created for the utility to improve efficiencies via cost reductions and other measures in the context of meeting SQIs and providing reliable service. To the extent savings that result from efficiency measures are reflected in an ROE higher than the allowed, they will be shared with the customer over the PBR term. Please also refer to the response to BCPSO IR 1.13.4.

13.6 Please fully explain how FBC proposes its principles be used in evaluating the FBC PBR plan as applied for.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.11.5. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

FBC proposes its principles be used as a guide in evaluating the FBC PBR plan as applied for. FBC's objective is to achieve the principles to the extent reasonably possible. B&V believes that all of the general principles and objectives that have been articulated in testimony, reports and academic literature are relevant to and inform the discussion of any PBR Plan (refer to the response to BCUC IR 1.10.2). B&V also believes that the principles articulated by FBC represent the most complete set of standards for assessing the FBC Plan based on FBC's prior experience with successful plans.

14.0 Reference: Exhibit B-1, Tab B, Section 4.2.4, page 32

14.1 Please provide a schedule that compares the historical performance (2007-2012) on the BC CPI (used in FBC's previous PBR plans) with the actual escalation, over the same period, of the inflation index currently proposed (per Section 6.2.2.1).

<u>Response:</u>

The following schedule compares the actual BC CPI to that forecast in FortisBC's annual revenue requirements from 2007 to 2012:

	BC CPI	
	Forecast	Actual[1]
2007	2.0%	1.8%
2008	2.1%	2.1%
2009	2.0%	0.0%
2010	2.1%	1.3%
2011	2.3%	2.4%
2012	2.2%	1.1%

[1] - source: www.bcstats.gov.bc.ca

15.0 Reference: Exhibit B-1, Tab B, Section 4.2.7, page 33

15.1 Please provide a schedule that sets out each year the 2007-2011 PBR term, the allowed ROE and the actual ROE achieved (prior to earning sharing).

Response:

The required schedule is provided blow.

The achieved Earnings post sharing has also been provided for clarity.

Year	Allowed ROE	Achieved ROE Before Sharing	Achieved ROE After Sharing
2007	8.77%	9.83%	9.23%
2008	9.02%	9.65%	9.28%
2009	8.87%	10.00%	9.41%
2010	9.90%	9.57%	9.65%
2011	9.90%	11.32%	10.67%

15.2 Please provide a schedule that sets out the derivation of the 2.7% "avoided rate increase".

Response:

A schedule is provided below that derives on a high level basis the "avoided rate increase".igh-level analysis indicates that the avoided rate increase is approximately 3.3%, higher than 2.7% indicated in Exhibit B-1, Tab B, Section 4.2.7, page 33.

Years	Approved Base Revenue	Customer Share (Returned the following Year)	% Rate Reduction	Cumulative % Rate Reduction
2007		1,931		
2008	220,950	1,313	0.9%	0.9%
2009	234,763	2,284	0.6%	1.4%
2010	259,274	(322)	0.9%	2.3%
2011	278,783	2,976	-0.1%	2.2%
2012	287,445		1.0%	3.3%
Total Customer Share		**8,182**	**Total Rate Reduction**	**3.3%**

16.0 Reference: Exhibit B-1, Tab B, Section 4.2.10, page 34

16.1 Please provide a schedule that reviews O&M performance over the 2007-2011 period and substantiates: a) the claimed $4 M in additional O&M savings and b) the claimed real reduction in O&M expense per customer.

Response:

The schedules provided below review O&M performance over the 2007-2011 period and substantiate the following:

a) Approximately $4M in O&M savings and

	O&M Expense		
	Approved	Actual	Savings
		($000s)	
2007	43,310	43,001	309
2008	45,310	44,725	585
2009	46,573	46,017	556
2010	47,645	46,148	1,497
2011	53,885	53,076	809
Total			3,756

b) Reduction in O&M expense per customer

	2007	2011
	($000s)	
O&M Expense	43,001	53,076
Less:		
Pension and OPEB	(2,917)	(4,686)
Trail Office Lease	(600)	(1,212)
Mandatory Reliability standards	-	(1,016)
2011 Sustaining Capital	-	(3,737)
Base O&M	39,484	42,425
Base O&M, Inflation-Adjusted	39,484	40,058
Average Customers	105,069	112,756
O&M Per Customer, Inflation-Adjusted	375.79	355.26
BC CPI	110.0	116.5

17.0 Reference: Exhibit B-1, Tab B, page 36, Table B5-1 and page 38 (lines 7-9)

Preamble: Exhibit B-1, page 38:

> *"The Alberta Utilities Commission (AUC) PBR initiative as well as the Ontario Energy Board (OEB) renewed regulatory framework for power distributors, which were applicable to a number of utilities, were resolved by hearing."*

17.1 Please clarify the nature of the Regulatory Proceeding associated with the OEB 4th Generation IR (Electricity) plan (Exhibit B-1, page 42). Was there a formal "hearing" before a panel of the Board?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.1.1. This response is identical to the FEI response to that IR.

The regulatory proceeding for the development of the OEB's 4th Generation IR framework was an OEB coordinated consultative process that included extensive stakeholder consultations, roundtables, conferences and written comments to determine the specific mechanics of the renewed regulatory framework for electric distributors. A written hearing was used to determine cost award matters such as cost eligibility and claims in relation to consultation activities for all eligible participants.

A timeline showing the steps in this regulatory proceeding can be found in the following link:

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework

18.0 Reference: Exhibit B-1, page 36, Table B5-1, Footnote #18

18.1 Please confirm whether definition of GDP IPI FDD is correct. In particular, the inclusion of the "times" term.

<u>Response:</u>

FBC confirms that GDP IPI FDD stands for Gross Domestic Product Implicit Price Index for Final Domestic Demand and that the inclusion of the "times" term in the footnote was incorrect.

GDP IPI FDD measures the price changes of all goods and services that make up the gross domestic product excluding net exports of goods and services.

19.0 Reference: Exhibit B-1-1, Appendix D2, pages 21-22

Union Gas Ltd ("Union") 2008-2012 IR Application, as filed June 28, 2007, Ontario Energy Board File No. EB-2007-0606, Exhibit B, Tab 1, page 8, Table 1 and pages 24-25

19.1 Please confirm that Union's original proposal for an X-factor for its 2008-2012 IR plan, inclusive of a 0% stretch factor and of an average use adjustment factor of 0.72, was 0.02.

<u>Response:</u>

This answer responds to BCPSO IR 1.19.1, 1.19.2 and 1.19.3.

As indicated in Exhibit B, Tab 1, Section 5.7 of Union Gas' 2008-2012 PBR application, the OEB's consultant, PEG, proposed an X-factor value of 0.52% (inclusive of a stretch factor):

PEG's X-factor Report	Percentage
TFP value	0.74
Average use (AU) factor	-0.72
Stretch factor	0.5
PEG's proposed X-factor (A)	**0.52**

Depending on the choice of the price cap formula design (using multiple or single price cap index) and based on PEG's X-factor report, Union Gas proposed three different X-factor values (with three different average use factors):

Category		PEG's measured TFP Value	Adjusted AU factor	Net X-factor
Separate price cap indices (PCIs) for different rate classes	General Services	0.74	- 1.12	- 0.38
	All other	0.74	0.00	0.74
Single Price cap index		0.74	- 0.72	0.02

A fourth X-factor value of 0.74 is also possible in case X-factor equals the TFP value (X-factor exclusive of AU factor and 0% stretch factor).

As Union Gas correctly stated in its application, "separate average use factors are typically not required in a price cap formula" and the proposed PEG's X-factor structure was due to the unique and unusual design of Union Gas' price cap formula and was done at the request of stakeholders to better understand the impact of the AU factor on the proposed price-cap formula. The final approved X-factor value was not based on any specific study and was determined in a negotiated settlement process

19.2 Please confirm that Union's original proposal for an X-factor for its 2008-2012 IR plan, inclusive of a 0% stretch factor and exclusive of an average use adjustment factor of 0.72, was 0.74.

Response:

Confirmed. Please refer to the response to BCPSO IR 1.19.1.

19.3 Please confirm that Union based its proposal, with adjustments, on research provided by Pacific Economics Group ("PEG") to the Ontario Energy Board.

Response:

Confirmed. Please refer to the response to BCPSO IR 1.19.1.

20.0 Reference: Exhibit B-1-1, Appendix D2, pages 21-22

Union's 2013 Rebasing Application Updated March 27, 2012

Ontario Energy Board File No. EB-2011-0210,

Exhibit A2, Tab 1, Schedule 1, page 6, Table 3

20.1 Please confirm that for the years 2008, 2009, 2010, and 2011, Union Gas Limited's benchmark ROEs used for the purpose of earnings sharing were 8.81%, 8.47%, 8.54%, and 8.10% respectively.

Response:

This response addresses BCPSO IRs 1.20.1, 1.20.2 and 1.20.3.

According to Union gas' 2013 Rates Application[2] (EB-2011-0210) the actual ROE (before weather normalization and earnings sharing), the benchmark ROE and the variance between them are as follows:

	2008	2009	2010	2011
Actual ROE %	13.35	11.22	10.91	11.57
Benchmark ROE %	8.81	8.47	8.54	8.10
Variance (bp)	454	275	237	347

20.2 Please confirm that for the years 2008, 2009, 2010, and 2011, Union Gas Limited's earned actual ROEs were 13.35%, 11.22%, 10.91%, and 11.57% respectively.

Response:

Confirmed. Please refer to the response to BCPSO IR 1.20.1.

20.3 Please confirm that for the years 2008, 2009, 2010, and 2011, Union earned ROEs in excess of the benchmark ROE by 454 basis points ("bp"), 275 bp, 237 bp, and 347 bp respectively.

[2] Exhibit A2 (Updated version), Tab 1, Page 6

Response:

Confirmed. Please refer to the response to BCPSO IR 1.20.1.

21.0 Reference: Exhibit B-1-1, Appendix D2, pages 21-22
Union's Application for Disposal of Deferral Account Balances and Earnings Sharing, as filed May 8, 2013
Ontario Energy Board File No. EB-2013-0109, Exhibit A, Tab 2, page 2

21.1 Please confirm that for 2012, the benchmark ROE for Union was 7.67%.

Response:

This is response addresses BCPSO IRs 1.21.1 and 1.21.2.

In its 2012 "Earnings sharing and disposition of deferral accounts" application (EB-2013-0109)[3] Union gas states that "the benchmark return on equity ("ROE") for 2012 was 7.67%. Union's actual ROE from utility operations in 2012 was 11.07% or 340 basis points above the 2012 benchmark ROE."

21.2 Please confirm that for 2012, Union reported an actual utility ROE of 11.07%, or 340 bp above the benchmark.

Response:

Please refer to the response to BCPSO IR 1.21.1.

[3] Exhibit A, Tab B, Page 2

22.0 Reference: Exhibit B-1-1, Appendix D2, pages 17-18
Enbridge Gas Distribution Inc. ("EGD") Application for a 2008-2012 IR Plan, Updated September 25, 2007
Ontario Energy Board File No. EB-2007-0615,
Exhibit B, tab 1, Schedule 1, pages 14-15

22.1 Please confirm that EGD proposed a revenue cap X-Factor adjustment of negative 0.77% (i.e., resulting in an annual revenue increase of 0.77% above inflation) based on "the reasonableness of the Company's proposal compared to PEG's recommendation."

<u>Response:</u>

According to Exhibit B, tab 3, Schedule 1, Page 1 of EGD's 2008-2012 IR plan, EGD reviewed PEG's report and proposed an X-factor of negative 0.15% (i.e., resulting in an annual revenue increase of 0.15% above inflation) in the revenue cap index design. EGD later published an updated version of its evidence in which the X-factor was changed to a negative 0.77%. The final X-factor was determined in a negotiated settlement and was not based on any specific X-factor or TFP study.

23.0 Reference: Exhibit B-1-1, Appendix D2, pages 17-18
EGD Application for Disposal of 2012 Deferral Account Balances and Earnings Sharing as filed July 19, 2013
Ontario Energy Board File No. EB-2013-0046
Exhibit I, Tab 4, Schedule 2, page 1, part b)

23.1 Please confirm that EGD reported a normalized ROE of 9.57% in 2012.

Response:

Confirmed.

23.2 Please confirm that the applicable benchmark ROE for EGD was 7.52%.

Response:

Confirmed. Based on EGD's 2012 ESM Application (EB-2013-0046[4]) the approved threshold ROE of 8.52% consisted of the approved formula return on equity for 2012 of 7.52% plus the approved 100 basis point dead band which led to a sufficiency in ROE of 1.05%.

23.3 Please confirm that EGD's evidence is that to reduce its actual normalized ROE to the benchmark ROE for 2012, a negative escalation factor of 4.06% would be required, i.e., for EGD to only earn the benchmark ROE in 2012, the revenue cap for 2012 would have had to be lower than it was by 4.06%.

Response:

Confirmed. In a response to an Energy Probe interrogatory, EGD states that when the Company uses an ROE of 7.52% in its Revenue Sufficiency Calculation as opposed to 8.52%, the gross revenue sufficiency becomes $40.3 million. To reduce the Approved 2012 Total Revenue by $40.3 million, an escalation factor of (4.06%) would have had to have been used in the 2012 IR formula.

[4] Exhibit B, tab 1, schedule 1. Page 4

24.0 Reference: Exhibit B-1-1, Appendix D1, pages 14 and 16

Preamble: Exhibit B-1-1, Appendix D1, page 14:

> *"The values for the productivity factor and stretch factor are not yet determined although a study has been filed and a decision for outstanding issues is due for mid-2013."*

Exhibit B-1-1, Appendix D1, page 16:

> *"the OEB will engage stakeholders in further consultation on establishment of an "efficiency carry-over mechanism" in due course."*

24.1 Please provide a copy of the study referenced in Exhibit B-1-1, Appendix D1, page 14 (last paragraph/last sentence).

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.2.1. This response is identical to the FEI response to that IR.

The mentioned study can be found in the OEB's website under the following link:

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_PEG_Report_20130503.pdf

Please note that this report was later revised slightly. The link below includes the red-lined version of the revised report:

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_redline_20130531.pdf

24.2 Apart from the "efficiency carry-over mechanism", were there any other PBR-related regulatory mechanisms that the OEB indicated it would be engaging stakeholders on in due course (Appendix D1, page 16).

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.2.2. This response is identical to the FEI response to that IR.

Page 61 of the OEB‟s "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" report states:

> *"Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:*
>
> *• The establishment of an "efficiency carry-over" mechanism;*
>
> *• Development of incentives to;*
>
> *- reward superior performance;*
>
> *- encourage innovation;*
>
> *- encourage asset optimization; and*
>
> *• Potential consequences for inferior performance."*

In addition, the determination of the X-factor and stretch factor values as well as the composite inflator was planned for mid-2013.

25.0 Reference: Exhibit B-1, Tab B, page 40, Table B6-1

Preamble: With respect to Controllable Expenses-Capital the Application states:

> *"The same formula as O&M will be used. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%."*

25.1 Please explain what the "limited rebasing" would entail.

<u>Response:</u>

As noted in the preamble quote limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%. If total regular capital expenditures vary by more than 10 percent above or below the total formula-based capital expenditures in any year, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the 10 percent deadband from the formula-based amount.

For example, if actual regular capital spending in a particular year was at 85% of the formula-based capital spending for that year, the difference of 5% between the 85% actual spending level and the 90% threshold level would be deducted from the next year's opening rate base for ratemaking purposes. However, the calculation of the formula-allowed annual capital spending amounts for future years' rate calculations will not be affected by this adjustment.

This provision of the PBR Plan will limit the impact of any capital savings during the PBR Period that would be shared between the customer and Company, and limit the amount of rebasing that would occur after the PBR Period.

25.2 Would the 10% is based on i) Actual capital expenditures for the most recent year available, ii) Projected capital expenditures for the bridge year, or iii) Forecast capital expenditures for the test year. For example, if rates were being set in 2015 for 2016 would the "test" be based on 2014 actuals, a 2015 projection (partially using actuals) or a forecast for 2016?

<u>Response:</u>

As an initial comment before addressing the question directly it should be noted regular capital spending falling outside the 90% to 110% of the formula-allowed amounts is expected to be an exceptional occurrence so the situation of "limited rebasing" being explored in the question may not happen during the PBR term.

That being said, the plus-or-minus 10% capital spending dead-band will be applicable in each year of the five-year term of the PBR. The actual regular capital expenditures in each year will be compared with the formula-allowed capital expenditures for the same year. If actual regular capital expenditures fall between 90% and 110% of the formula-allowed amount for a particular year, no adjustment will be made. Since the Annual Review will be held in the fall of the year before the full year's capital spending is known, it will be necessary to make the initial "limited rebasing" adjustments based on a projection of the year's capital spending. However, if there are variances in actual capital spending amounts relative to the projection made at the annual review that require changes to be made to the "limited rebasing" adjustment these will be corrected in the following year.

Using the years noted in the question to illustrate this the annual review in the fall of 2015 for setting the 2016 rates would include the following in this regard:

- If 2015 projected regular capital expenditures are expected to be less than 90% or more than 110% of the 2015 formula allowed capital expenditures an adjustment to the opening 2016 rate base for ratemaking purposes will be made. Projected spending of less than 90% will decrease the opening rate base and projected spending of more than 110% will increase the opening rate base. (As noted above variances between the 2015 projected capital spending under the formula and 2015 actual capital spending will be trued up in the 2016 annual review.)
- If the 2014 actual regular capital spending compared to the 2014 projected regular capital spending (from the previous year's annual review) requires a revision to the opening rate base because of differences that fall outside 90% to 100% of the 2014 formula-allowed spending amount, the required adjustment will be made to opening rate base for rate making purposes.

26.0 Reference: Exhibit B-1, Page 43, line 15

Preamble: On page 43 of its Application, FBC provides the derivation of its proposed I-Factor. FBC proposes a weighted I-Factor with a weighting of 55% of BC Average Weekly Earnings (AWE) and 45% of BC CPI. AWE appears to represent labour input costs, and CPI is to represent the cost of non-labour. BCPSO is aware of the Electric Utility Construction Price Index (EUCPI) for electric utilities. The BCPSO requires information to understand the choice of indices and the weightings.

26.1 Please explain why FBC did not use EUCPI as the I-Factor for capital costs.

Response:

The goal of a PBR is to emulate a competitive firm operating in a competitive market. Therefore, an individual firm's inflation rate should be measured against an industry-wide inflation rate. The BC CPI is a broad indicator that represents the rate of price increases across all industries in BC, and it is therefore appropriate to use this measure as a benchmark for evaluating an individual firm's performance.

The EUCPI is solely for construction of transmission and distribution facilities. As such, it does not cover other types of capital costs such as IT systems, tools and equipment costs and also does not cover the projects related to sustainment. The index also has no component for other non-labor costs. B&V states that since the type of projects that EUCPI would track are typically the CPCN type projects not included in the PBR Plan, the index would not be useful in tracking general inflation covered under the PBR I-X formula.

26.2 Please provide the EUCPI data for 2011, 2012, 2013 and forecast for 2014.

Response:

Statscan's website does not provide forecasts for the EUCPI. However, historical data for the period 2008 – 2012 is provided in the table below:

Construction price indexes[5]
(Electric utility)

	2008	2009	2010	2011	2012
	Electric utility				
	1992=100				
Distribution systems	150.3	151.1	155.1	160.1	161.6
Transmission line systems	148.8	149.7	150.5	154.0	154.3
	% change				
Distribution systems	1.0	0.5	2.6	3.2	0.9
Transmission line systems	4.3	0.6	0.5	2.3	0.2

Source: Statistics Canada, CANSIM, table 327-0011 and Catalogue no. 62-007-X.
Last modified: 2013-04-04.

26.3 Please provide actual labour and supplies for 2008-2012 for each of O&M and Capital, and the calculation of actual ratio of labour and non labour input costs.

Response:

The tables for O&M and Capital have been provided below.

[5] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ144d-eng.htm

O&M	2008	2009	2010	2011	2012
			($000's)		
Labour	25,838	27,223	26,497	28,899	28,777
Non-labour	18,887	18,794	19,651	24,174	24,765
	44,725	46,017	46,148	53,073	53,542
Ratio of Labour	58%	59%	57%	54%	54%
Ration of Non-labour	42%	41%	43%	46%	46%

Capital	2008	2009	2010	2011	2012
			($000's)		
Labour & Contract	64,772	68,118	93,546	53,398	35,284
Non-labour	34,815	31,051	36,945	22,811	17,108
	99,587	99,169	130,491	76,209	52,392
Ratio of Labour &Contract	65%	69%	72%	70%	67%
Ration of Non-labour	35%	31%	28%	30%	33%

27.0 Reference: Exhibit B-1, Page 44, lines 12-15

Preamble: On lines 12-15 of page 44, FBC indicates it will update its forecast of the I factor for 2015-2018 in the annual review meetings. The BCPSO requires an understanding of why I-factors are not trued up to actual inflation

27.1 Please confirm that the 2014 I-factor will not be trued up for actual inflation. If not confirmed, please fully explain. If confirmed, please fully explain why the I-factor will not be trued up.

Response:

Confirmed, the 2014 I-factor will not be trued up for actual inflation. Please refer to the responses to BCUC IRs 1.12.1 and 1.12.2 for a detailed explanation of the reasons why the I-factor will not be trued up.

28.0 Reference: Exhibit B-1, Tab B, Section 6.2.2.2, page 44

Exhibit B-1-1, Appendix D8, pages 52-53

Preamble: Section 6.2.2.2, page 44 states:

> *"The X-Factor (also known as efficiency factor or productivity offset) is a fundamental element of performance-based regulation. It represents the amount by which a company is expected to outperform the industry and economy-wide productivity gains."*

Appendix D8, pages 52-53 states:

> *'In general terms, the X factor can be viewed as the expected annual productivity growth during the PBR term. Through the I-X mechanism, a PBR plan is designed so that the changes in the prices of the company's distribution services reflect changes in input prices as reflected by the I factor and the rate of expected productivity growth.'*

28.1 Please clarify whether the X-Factor is meant to represent: a) the expected productivity growth for the company subject to PBR or b) the difference between the productivity growth of the Company and the overall productivity growth of the industry/economy.

<u>Response:</u>

B&V provides the following response.

It is neither a) nor b). In general the X-Factor is based on the central tendency for TFP growth based on a sizeable sample of electric utilities. The X-Factor in this case represents a targeted level of productivity that includes a substantial stretch factor.

29.0 Reference: Exhibit B-1, Appendix D2, pages 1-2 and 10

Exhibit B-1, Appendix D9-3, pages 59-60

Preamble: Appendix D2, page 1:

> *"TFP is simply a measure of how efficiently a firm converts total inputs into total outputs."*

Appendix D2, page 2:

> *"The analysis of TFP measures how efficiently the firm's output changes as the inputs are changed. TFP is positive when output changes faster than input and is negative when inputs change faster than output."*

Appendix D2, page 2:

> *"A negative TFP means that costs are rising faster than inflation and a positive TFP means cost are changing slower than inflation."*

Appendix D2, page 10:

> *"For each of the measures, input and output, the annual change is calculated and the difference between the changes represents the TFP for each particular output measure."*

Appendix D8, page 59:

> *"In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs."*

Appendix D8, page 60:

> *"Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question."*

29.1 Does FBC agree that TFP growth represents the difference between the growth rates of a firm's (or industry's) physical outputs and its physical inputs? If not, what does TFP growth represent?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.3.1. This response is identical to the FEI response to that IR.

B&V provides the following response.

TFP in its most formal economic definition measures the growth in output not accounted for by the growth in inputs. In the context of the TFP analysis for estimating the X-Factor, the measure is the difference between the rate of growth in outputs minus the rate of growth in inputs as we have defined it in the TFP Report in Appendix D-2.

29.2 Does FBC also agree that TFP growth can be represented as:

TFP Growth (%) = Physical Output Growth (%) – Physical Input Growth (%)

If not, please provide a similar formulaic representation of what FBC considers TFP growth to represent.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.3.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Yes. Please refer to the response to BCPSO IR 1.29.1.

29.3 Please reconcile the two statements referenced above from Appendix D2 (page 2) as each appears to provide a different definition of TFP.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.3.3. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V provides the following response.

Neither of the two statements is a definition of TFP but rather an explanation of the impact of TFP as it relates to the costs of providing utility service. Please also refer to the response to BCPSO IR 1.29.4.

29.4 Please explain how "negative TFP means that costs are rising faster than inflation and positive TFP means that cost are rising slower than inflation"?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.3.4. This response is identical to the FEI response to that IR.

B&V provides the following response.

These are just mathematical conclusions based on the logic of TFP. If we assume constant input prices and the quantity of inputs rises then mathematically costs increase faster than the rate of inflation because prices were assumed to be constant to illustrate this point. Likewise the opposite is also true.

30.0 Reference: Exhibit B-1, page 47

30.1 Please fully explain why Figure B6-1 only starts in the year 2000.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.14.1. This response is identical to the FEI response to that IR.

The data in Figure B6-1 was taken from B&V's survey of TFP studies. B&V provides the following response.

As discussed elsewhere, the latest TFP studies represent a more relevant time frame to review.

30.2 Please provide a table similar to Figure B6-1 that contains data for each year from 1980-2000

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.14.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC cannot provide a similar figure for the period between 1980 and 2000. FBC's position regarding the downward TFP trend is related to the more recent period. In addition, B&V notes that the use of PBR plans and TFP studies for determination of X-factor for natural gas and electricity utilities were rare in North America during the 1980s and that the majority of the related PBR plans were started after 1995.

30.3 Please provide a list of other TFP studies conducted by B&V for regulated utilities, including the proceeding that the study was filed in.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.14.3.

Please refer to the response to CEC IR 1.74.3.

30.4 Please provide the actual values used to create Figure B6-1 and the references supporting each value.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.4.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

The table below includes the actual TFP values and their respective references used to create Figure B6-1.

State/ Province	Utility	Sector	Term	Measured TFP	Reference
CA	PacifiCorp	Electric	2011-13	0.50%	Decision 10-09-010
CA	Sierra Pacific Power	Electric	2009-11	0.50%	Decision 09-10-041
CA	San Diego Gas and Electric (SDG&E)	Gas	2000-02	2000-1.08% 2001-1.23% 2002-1.38%	Decision 99-05-030
CA	SDG&E	Electric	1999-2002	2000-1.32% 2001-1.47% 2002-1.53%	Decision 99-05-030
MA	Berkshire Gas	Gas	2004-11	0%	Docket D.T.E. 01-56
MA	NSTAR	Electric	2006-12	0%	Docket D.T.E. 05-85
MA	Boston Gas	Gas	1997-2001	0.50%	Docket D.P.U. 96-50-C (Phase I)
ME	Bangor Gas	Gas	2000-12	0%	Docket 970795
ME	Central Maine Power	Electric	2009-2013	1.0%	Docket 2007-215
ME	Central Maine Power	Electric	2001-2007	2.0%-2.9%*	Docket 99-666
Ontario	All utilities	Electric	2010-2013	0.72	EB-2007-0673
Ontario	All utilities	Electric	2000-2003	1.25%	RP-1999-0034
Ontario	All utilities	Electric	2006-2009	1.00%	EB-2006-0089
Ontario	Union Gas	Gas	2001-2003	1.10%	RP-1999-0017
CA	SoCAL Gas	Gas	1997-2002	1.50%	Decision 96-09-092

** Gradual increase over the 8 years term of the plan.*

Please refer to Attachment 30.4 for the working excel spreadsheet of this table as well as the calculations that are used to construct the Figure B6-1.

30.5 What difference (if any) is there between "approved TFP" (used in the title of the Figure) and "measured TFP" as used in the legend for the Figure? Are these the TFP (X-factor) values approved for use in PBR plans or the measured TFP values calculated as input into the determination of the X-Factor for various PBR plans?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.4.2. This response is identical to the FEI response to that IR.

In the context of Figure B6-1 there is no difference between the approved and measured TFP values. These are the TFP values approved by the regulators either as the approved X-factor value (where TFP equals X-factor) or as a part of the approved X-factor value (in case the X-factor also includes an additional stretch factor).

30.6 Please identify those US electric distribution utilities that are currently operating under PBR plans and indicate the approved X-Factor for each. Note: In those cases where there is an approved "stretch factor" as well as X-Factor, please also report the Stretch Factor. Also, for the US electric distribution utilities provided, please identify those using a building block approach, similar to the PBR program proposed by FBC.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.4.3. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Based on the Commission's staff letter dated April 18, 2013 our survey for active PBR plans was limited to Canadian distributors. Given the number of electric utilities in the U.S., FBC may not be aware of all the active PBR plans in the US electric industry. Please refer to the response to BCPSO IR 1.30.4 for a list of US utilities with active PBR plans between 2000 and 2012. FBC has not done the extensive work to determine which of the plans are based on the building block approach since the plans must be examined in detail in order to make such a determination. Please also refer to Attachment 30.6 for a copy of the April 18, 2013 letter.

31.0 Reference: Exhibit B-1, page 48 (lines 16-20)

31.1 What business conditions are expected to be the same during the period used to measure TFP (2007-2011) and as during the proposed term of the PBR plan (2014-2018)? In particular, please address the extent to which the economic conditions (e.g. GDP growth) are expected to be the same in the two periods.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.5.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

The business conditions related to output measures, namely customers and capacity, are expected to be relatively the same in the two periods. For instance, the growth rate of customer additions during the 2007-2011 period is similar to the forecast rate of customer additions during the PBR period (with the expected growth rate during the PBR term slightly lower). Input conditions are expected to be reflected by the proposed I-Factor.

FBC did not claim that the economic conditions such as GDP growth are expected to be the same (but rather business conditions specific to BC's natural gas utility industry). B&V indicates that, since FBC's output measures are not related to volumetric indices (as opposed to the AUC TFP calculation), the macro economic conditions do not have the same material impact on FBC's productivity as measured by capacity as the output.

32.0 Reference: Exhibit B-1, page 45 (lines 7-9)

Exhibit B-1, page 47 (lines 14-16)

32.1 Does FBC consider its proposed inflation factor to be representative of input price escalation for the electricity transmission/distribution industry or, in principle, should the X-Factor for the proposed plan also include an adjustment "for any difference between the inflation index used in the PBR index formula and the rate of inflation for the regulated sector" (page 45)?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.6.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V provides the following response.

The inflation factor or the I-Factor under PBR is an estimate of the expected price increases associated with inputs for the electric utility. That factor has both a general inflation component and a labor inflation component designed to track the price increases expected by FBC. In general, the I-Factor may be a general measure of inflation or a utility specific measure based on actual utility input cost changes. Since a general index of inflation will not precisely match the actual inflation for utility inputs some econometric studies develop an adjustment for the difference between the general index of inflation and the actual inflation rates for the utilities in the TFP study. In essence, this estimated difference is an attempt to develop an industry specific measure of inflation defined as the sum of the general inflation and the calculated adjustment factor. Under this method, the adjustment factor would be added to the X-Factor along with the TFP estimate and if applicable a stretch factor. Since we are using the composite inflator that tracks input price increases the adjustment is not required.

33.0 Reference: Exhibit B-1, page 48 (lines 25-29)

Exhibit B-1-1, Appendix D2, page 10

33.1 Please provide documentation that clearly explains the "Kahn" methodology.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.7.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Please refer to the response to CEC IR 1.74.14 which includes the testimony of Alfred E. Kahn.

33.2 Please clarify, if not done so in response to the previous question, whether the "expenses" that were deducted from Operating Revenue in the Kahn methodology were just O&M expenses and production costs or whether they also included depreciation (page 58, lines 28-30).

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.7.21. This response is identical to the FEI response to that IR.

B&V provides the following response.

The Kahn method applied to oil pipelines so there was no gas costs included in the operating expenses. The measure operating expenses includes both O&M and General expenses (See FERC Form 6). Depreciation expense is recorded in General Expenses as account 540.

33.3 Please indicate how the Kahn methodology was used in setting the price cap index for the oil pipelines regulated by FERC. In doing so, please confirm whether it was used as follows:

a) The Kahn methodology was used to establish the historical annual increase in costs (per unit of output) for the industry,

b) The historical differential between cost escalation for the industry and escalation in the Producer Price Index for Finished Goods (PPI-FG) was determined, and

c) The price cap formula was then based on the future escalation in the PPI-FG index less the differential.

If not, how was it used?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.7.3. This response is identical to the FEI response to that IR.

B&V provides the following response.

The Kahn Method was used to determine the X-Factor in the formula for the price cap applicable to oil pipelines.

Items (a), (b) and (c) are confirmed.

33.4 Did the price cap formula used by FERC for the oil pipeline industry include both an inflation factor and an X-factor?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.7.4. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Yes. The FERC price cap formula includes both an inflation factor (Producer price index for finished goods or PPI-FG) and an X-factor. For further information on the X factor please refer to the response to BCPSO IR 1.33.3.

33.5 Does FBC consider the input price increases it experienced during the 2007-2011 period to be similar to those experienced by the US electric utilities used in B&V's study over the same period? If not, were FBC's experienced input price increases higher or lower and why?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.7.5. This response is similar to the FEI response to that IR, however, some minor changes to be appropriate for FBC.

There has been no study of the input price increases for FBC since FBC was not part of the sample. B&V explains that the differences between the escalation of prices would not inform the analysis of TFP since the PBR Plan uses local measures of inflation that would not necessarily apply to the US sample of electric utilities. The essential element of the TFP Report is that the TFP measures productivity not absolute price changes.

34.0 Reference: Exhibit B-1-1, Appendix D2, Schedule 2

34.1 Did B&V review the reasonableness of the data before using it in the TFP analysis?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.8.1. This response is identical to the FEI response to that IR.

Yes.

34.2 A number of utilities (e.g. ALLETE Inc., Ameren Missouri, Appalachian Power and Arizona Public Service) report year over year decreases in installed substation capacity and/or miles of transmission/distribution line. Please explain how such decreases could occur.

Response:

B&V provides the following response.

There are a number of ways the decreases may occur. First, there are demographic reasons that may allow a utility to reduce substation capacity and transmission/ distribution line. To name a few, the decline in manufacturing facilities in the rust belt has reduced the need for these facilities because of lower loads and fewer customers. This represents a long term trend in some service areas. The loss of manufacturing also meant loss in residential customers and a change in the overall customer count in other classes as well. Second, restructuring has resulted in the formation of independent transmission utilities using assets previously owned by the vertically integrated utility. Third, the conversion of premises from manufacturing to mixed use residential and small commercial would allow a utility to replace aging infrastructure with lower capacity substations. Miles of distribution lines could also change in the area when three phase service is replaced by single phase service. Fourth, facilities may have been abandoned as the result of changes such as plant decommissioning, rerouting service from other facilities and so forth.

34.3 Please provide Schedule 2 in a working Excel file.

Response:

Please refer to the response to CEC IR 1.74.1.

35.0 Reference: Exhibit B-1-1, Appendix D2, Schedule 2

35.1 Please confirm whether the values reported in column V include O&M costs and Production costs but not Depreciation expense.

Response:

Confirmed.

35.2 Please confirm that column AC is a measure of the change in total costs, including the impact of both inflation (i.e. increases in the price of inputs) and changes in the quantity of inputs used. If not, please explain why not and what it does provide a measure of.

Response:

Column AC is a measure of the change in total costs (calculated as the price of the input times the quantity of the input times the change in input quality for each input in the category including labor, materials and supplies, rents, outside services etc.).

35.3 Please confirm that Columns AM, AO and AQ represent the difference between the change in physical output (measured various ways) and the change in costs (including the impact of both changes in physical inputs and change in the cost of inputs). If not, please explain why not and what the columns do represent.

Response:

Please refer to the response to BCPSO IR 1.35.2. These columns represent the differences between composite measures of outputs and inputs.

35.4 Please explain how/why the values calculated in Columns AM, AO and AQ are consistent with the definition of TFP (and the associated X-Factor) as used in the PBR formulation set out at Exhibit B-1, page 29.

Response:

Please refer to the response to BCPSO 1.35.3.

35.5 Wouldn't incorporating a TFP factor based on the results from Columns AM, AO or AQ into a PBR formula that also included a inflation factor result in double counting the impact of inflation? If not, why not?

Response:

B&V provides the following response.

No. The measures are an ex-post composite measure of inputs and outputs and as such do not include a measure of inflation.

36.0 Reference: Exhibit B-1, Table B6-4 and Table C4-1

Preamble: In Table B6-4, FBC provides a reconciliation of 2013 Decision O&M base O&M. In table C4-2, FBC provides an itemized list of Sustainable Savings by function. The BCPSO requires information to assess the adjustments to O&M

36.1 Please fully explain why Table B6-4 should start with Approved O&M and not actual, or a more recent forecast.

Response:

The Approved O&M is the appropriate starting point for Table B6-4 because the Company's O&M was thoroughly reviewed and tested in FBC's 2012-2013 RRA oral hearing. The Company did incorporate adjustments to that amount that have the similar effect of updating key information to account for actual experience. Further as discussed in section 6 at page 51 this approach was successfully used for the Company's 2007-2011 PBR.

36.2 Please provide a detailed analysis of the costs included in Sustainable Savings of $452,000.

Response:

Please refer to the response to BCUC IR 1.96.2.

36.3 Please provide the amount of (i) Mandatory Reliability Standards, (ii) Provincial Sales Tax, and (iii) Pension (O&M Portion) that is already included in the 2013 Decision O&M of $57,621,000.

Response:

Of the 2013 Decision O&M expenditures of $57.621 million:

i. Approximately $1.2 million relates to Mandatory Reliability Standards;

ii. Provincial Sales Tax has no budget in the 2013 Decision because the reinstatement of the PST was approved in 2012 after the 2012-2013 Revenue Requirements filing; and

iii. Approximately $4.2 million relates to Pension/OPEB (O&M portion), which includes the Defined Benefit and Defined Contribution pensions.

36.4 Please provide a reconciliation of the amounts included in Table B6-4 and in response to 5.2 above.

Response:

Please note that the response below is made with the assumption that '5.2 above' in the question refers to BCPSO IR 1.36.2.

Please refer to Exhibit B-1, Tab-C, Table C4-2, Page 113: Determination of Base O&M by Department of the application for the reconciliation to Table B6-4, Exhibit B-1, Tab-B, Page 51.

36.5 In Table C4-1C, FBC provides actual O&M for 2010, 2011, 2012, and projected for 2013, and Approved O&M for 2012 and 2013. Please fully explain why Table B6-4 should start with Approved O&M and not actual, or a more recent forecast.

Response:

Please refer to the response to BCPSO IR 1.36.1.

36.6 In Table C4-1, FBC provides actual O&M for 2010, 2011, and 2012. The actual O&M for 2012 is $53,544,000, compared to 2011 actual O&M of $53,075,000, an increase of $469,000 (0.88%). The 2013 projected O&M is $57,169,000, an increase of $3,625,000 (6.77%). Please fully explain why the 2013 projection is so much larger than 2012 actual O&M, particularly in light of the small increase in 2012.

Response:

The table below reviews the annual Gross O&M percent increase during the 2011-2013 periods. For the purpose of this analysis certain amounts have been normalized for comparability.

The table below indicates that the percent increase of Post Normalized Gross O&M are uniform and within reasonable variance levels of labour escalation and inflation.

Additionally, FBC notes that the O&M amounts in 2012 were lower than originally forecasted due to unfilled vacancies that have not been quantified in the table below.

O&M Gross	Pre Normalized Gross O&M	Pre Normalization % Increment	COK Addl. Cost	Average Executive Savings	Corporate Other Savings	One Time Insurance Deductible	Trail Lease Savings	One Time Insurance Refund to Customers	Post Normalized Gross O&M	Post Normalization % Increment
Actual 2011	53,075		-	-	-	-	-	-	53,075	
Actual 2012	53,544	0.88%	-	440	287	(200)	-	447	54,518	2.7%
Projection 2013	57,169	6.77%	(1,344)	-	-	-	303	-	56,128	3.0%

37.0 Reference: Exhibit B-1, page 52 line 24, Table B6-5 and Table C4-1,

Preamble: On line 24 of page 52, FBC provides the O&M formula, in Table B6-5, FBC provides the calculation of O&M for each year of the PBR program, and in Table C4-1, FBC provides its O&M costs. In the O&M formula, there is a customer factor. The BCPSO requires an understanding of the history of O&M per customer.

37.1 Please provide the actual O&M data for the years 2008-2009 for in a table similar to table C4-1

Response:

Please refer to the response to ICG IR 1.27.1.

37.2 Please provide actual customers for the years 2008-2012, and projected for 2013-2014.

Response:

The actual customers for the years 2008 – 2012 and projected customers for 2013-2018 can be found in Exhibit B-1, Section C1, Table C1-3.

37.3 Please provide an extension of Table C4-1, including the response to sub question 2 above, that result in Controllable O&M for each year.

Response:

Please refer to the table below that has extended Table C4-1 and includes controllable O&M for 2008-2012 actual data and projected 2013 data.

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Generation	$ 1,894	$ 2,152	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,924	15,057	14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 6,272	5,835	5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,079	1,150	1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	$ 546	739	827	893	986	1,069	1,124	1,124
Information Technology	$ 2,834	2,938	2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 1,184	1,143	1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 1,651	1,028	993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 2,834	3,537	3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 616	645	727	867	894	925	953	953
Finance & Regulatory	$ 3,631	3,624	3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,540	1,558	1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,006	2,066	2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 3,716	4,545	3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-	-	-	-	-	-
Pension	$ (2,542)	(3,165)	(3,749)	(4,670)	(5,951)	(3,957)	(6,222)	(3,691)
CEP Decision G-195-10 Capital to O&M	$ -	-	-	(3,518)	(3,169)	(3,147)	(3,153)	(3,153)
Mandatory Reliability Standards	$ -	-	-	(1,016)	(1,179)	(1,179)	(1,187)	(1,187)
Trail Lease	$ (753)	(1,212)	(1,212)	(1,212)	(1,212)	(1,212)	(909)	(909)
HST / PST Adjustment	$ -	-	-	151	-	-	-	-
Insurance	$ (1,570)	(1,527)	(1,539)	(1,399)	(1,946)	(1,441)	(1,588)	(1,471)
Total O&M	**$ 39,860**	**$ 40,113**	**$ 39,649**	**$ 41,411**	**$ 40,087**	**$ 43,907**	**$ 44,110**	**$ 47,210**
Customers	**108,722**	**110,286**	**111,552**	**112,756**	**113,587**	**113,588**	**121,566**	**124,581**
O&M per Customer	**$ 367**	**$ 364**	**$ 355**	**$ 367**	**$ 353**	**$ 387**	**$ 363**	**$ 379**

37.4 Please provide the average number of customers, for the years 2008 – 2012 that correspond to the average customers provided on line 8 of B6-5

<u>Response:</u>

The average number of customer for the years 2008 to 2012 that correspond to the average customers provided in line 8 of B6-5 is below.

Average Number of Customers from 2008 to 2012

	2008	2009	2010	2011	2012
Average Number of Customers	108,722	110,286	111,551	112,754	113,587

38.0 Reference: Exhibit B-1, Table C4-1

Preamble: In Table C4-1, FBC provides actual and forecast O&M costs. In the formula on page 52, it appears that the derivation of O&M is really an O&M per customer factor. In Table C4-1, FBC provides O&M by the following functions:

- Generation,
- Operations,
- Customer Service,
- Communications & External Relations,
- Energy Supply,
- Information Technology,
- Engineering Services,
- Operations Support,
- Facilities,
- Environmental Health & Safety,
- Financial & Regulatory,
- Human Resources,
- Governance,
- Corporate, and
- Advanced Metering Infrastructure.

The BCPSO requires information to understand the cost drivers of each function, and how changes in each function are impacted by changes in customers.

38.1 Please fully explain the cost drivers for each function listed in Table C4-1.

Response:

The drivers affecting departmental costs are explained in detail for each department in the Operations and Maintenance section of the Application, Section C4.

39.0 Reference: Exhibit B-1, Tab B, page 53 (Table B6-5)

39.1 Over the course of the PBR plan (i.e. 2014-2018), does FortisBC plan to update its forecast O&M reductions due to AMI for purposes of determining total O&M under PBR?

Response:

If the forecast O&M reductions from AMI change over the course of the PBR plan, then FortisBC would update its forecast.

39.2 If yes, please explain how the forecast will be developed. In particular, will the updated forecast involve "new" forecasts of what the O&M expenses would have been without AMI?

Response:

Any revised forecasts would be based on revised timing of forecast O&M increases or decreases, or if actual experience was measurably and materially different than forecast.

The "status quo" forecast of non-AMI O&M expenses will not be updated since it was based on the best assumptions that could be made at the time it was developed.

39.3 Why should the forecast of O&M reductions due to AMI be updated? Why shouldn't the forecast savings used to justify the CPCN application and approval be reflected in the PBR plan going forward?

Response:

With all projects, the forecast costs and benefits are subject to some uncertainty. This is particularly true of the AMI project, which as described in the CPCN application represents a significant change to many parts of FBC's business. The forecast O&M reductions associated with the AMI project are based on the best information available at the time of the CPCN application. Although FBC is confident that the forecast O&M reductions remain accurate, there is still uncertainty regarding the actual amount of reductions that may be achieved.

As part of the CPCN application process, the Commission weighs the evidence in order to determine whether the level of benefit claimed is reasonable and whether the time frame over which those benefits are claimed is reasonable. FBC believes it took an appropriately conservative approach to assessing the probable benefit of the AMI project, helping to ensure that the forecast benefits are achieved or exceeded. Indeed, the level of forecast O&M reductions was accepted by the Commission in Order C-7-13 as "reasonable over the life of the project."

Order C-7-13 correctly recognizes the inherent uncertainty associated with the timing and quantum of costs and benefits, stating that "FortisBC is directed to file with the Commission an Annual Cost/Benefit Tracking Report on the AMI Project benefits (reduced costs) and the new operating costs of the AMI program for each of the first 5 years following the end or substantial completion of the AMI Project." FBC does not believe it is reasonable, nor is it consistent with the treatment of other capital projects, to require the utility to assume all risk associated with the realization of benefits attributable to the project. Increases/decreases in the level of forecast O&M reductions which are beyond the influence or control of the Company should not result in a penalty or windfall to shareholders. A requirement for FBC to bear such increased risk could ultimately result in a significant shift of the risk profile of the Company, and may have the unintended result of incenting the Company to be overly conservative in conducting future project cost/benefit analyses. For these reasons, the Company considers its proposal to track forecast O&M reductions related to AMI outside of the PBR formula (and to update the forecast O&M reductions as required) as reasonable.

40.0 Reference: Exhibit B-1, Tab B, pages 55 and 58 (Table B6-7)

Preamble: FortisBC describes its proposal to exclude CPCN expenditures from the PBR formula as being akin to the adoption of a "capital tracker" which is included in PBR plans elsewhere.

40.1 Please compare the types of projects that would be associated with FortisBC's CPCN Applications with the types of projects that would qualify a) under Alberta's capital tracker mechanism or b) Ontario's incremental capital module mechanism.

Response:

CPCN projects for FBC are large projects that are not included in the formula-based capital expenditure allowance. Projects that FBC wishes to undertake outside the formula must be brought forward as a CPCN application or as part of the Annual Review process for BCUC review and approval, and will only be added to rate base after receipt of approval from the Commission and the project is completed and in service.

The eligibility criteria for capital tracker applications under AUC's and OEB's regulatory frameworks are as follows:

AUC's capital tracker mechanism:

Based on the recommendations of its consultant (Dr. Makholm), the AUC's Decision 2013-237 adopted the following criteria for PBR's capital tracker mechanism:

I. **The project must be outside of the normal course of the company's ongoing operations**: Further in the following ATCO Gas' 2013 capital tracker application (Proceeding ID 2131, Appendix A) Dr. Makholm defined the projects "outside the normal course" as those which cannot be dealt with under I-X formula. The AUC also stated that the companies shall demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety.

II. **"Ordinarily" the project must be for replacement of existing capital assets or undertaking the project must be required by an external party**: It should be noted that under this criterion, all projects (revenue neutral and/or revenue generating) are still eligible for the capital tracker mechanism and the AUC would have the flexibility of approving load growth related projects based on its judgement.

III. **The project must have a material effect on the company's finances**: The AUC did not set any definite materiality threshold and will judge the materiality of the projects on a case by case basis.

The initial applications under the capital tracker mechanism have been filed by companies with the AUC in September 2013; however none of the applications have reached a decision yet and therefore it is not possible to be definitive about the kind of projects that will be approved in Alberta. The Alberta utilities are not finding the capital spending covered by their PBR formulas to be adequate and will be seeking additional capital under the capital tracker mechanisms.

<u>OEB's incremental capital module (ICM):</u>

OEB introduced the ICM in its 3rd Generation IR and set the following eligibility criteria:

I. **Materiality**: The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor. Due to the variety of electric utilities characteristics in Ontario (for instance differences in size of rate base), the OEB defined the following eligibility formula to determine the materiality threshold suitable for each utility:

   Threshold value = 1 + (RB / d)* (g + PCI * (1+g)) + 20%

   Where:

   RB = rate base included in base rates ($);

   d = depreciation expense included in base rates ($);

   g = distribution revenue change from load growth (%); and

   PCI = price cap index (% inflation less productivity factor less stretch factor).

II. **Need**: Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.

III. **Prudence**: The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective for ratepayers.

In 4th Generation IR, OEB revised its filing requirements for electricity distributors to "remove words such as 'unusual' and 'unanticipated' as prerequisites to an application for incremental capital." Accordingly the OEB has approved ICM related rate riders for wide range of electric capital projects such as:

- transmission station expenses,
- wholesale metering assets,
- transformer construction, rehabilitation, and replacement,
- cable rebuilds,
- circuit breaker retrofits, and
- new substations, …

For instance in a recent application for Hydro One Networks (EB-2012-0136, Decision and Procedural Order No.4), the OEB approved number of projects such as:

- Customer information system replacement
- DS voltage conversion
- Wood pole replacement
- Enhanced asset management
- Destination enterprise GIS database development
- Distribution system modifications, etc.

40.2 After a CPCN application and the associated capital expenditures have been approved, does FortisBC intend to update the capital spending for such projects in subsequent PBR-based rate applications over the 2014-2018 period?

Response:

FBC intends to provide brief CPCN project status updates at the Annual Reviews and Mid Term Assessment Review during the PBR Term. Any changes in CPCN capital estimates subsequent to approval are changes that are usually beyond the Company's control. Approval for any changes to CPCN capital expenditures (and the associated additions to plant in service) will be sought as part of the Annual Review process. FBC considers this appropriate since customers benefit from CPCN projects, and are responsible for recovery of all prudently incurred expenditures. This is the same treatment as in the previous FBC PBR.

Further FBC will be filing regular project status reports as required in any CPCN Decisions issued by the Commission.

40.2.1 If yes, please explain why such updates are appropriate.

Response:

Please refer to the response to BCPSO IR 1.40.2 above.

41.0 Reference: Exhibit B-1, Table B6-6

Preamble: In Table B6-6, FBC derives capital applicable to PBR by starting with Approved Capital. The BCPSO requires an understanding of why PBR capital should not start with actual capital.

41.1 Please fully explain why Table B6-6 should start with Approved Capital and not actual, or a more recent forecast.

Response:

The Approved Capital is the appropriate starting point for Table B6-6 as the Company's capital budget was thoroughly reviewed and tested by the Commission and stakeholders in FBC's 2012-2013 RRA oral hearing. It should be noted that FBC has not included an adjustment to the 2013 Base for the former City of Kelowna utility assets as the Company intends to absorb the future capital expenditures related to those assets within the capital funding under the formula.

42.0 Reference: Exhibit B-1, Table B6-6 B6-7, C5-1, and C5-2

Preamble: In Table B6-7, FBC provides a reconciliation of 2013 Base Capital to PBR capital. In Table C5-1, FBC provides historic capital expenditures for 2010-2012.

42.1 Please provide a schedule similar to Table C5-1 that provides historic capital expenditures for 2008 and 2009.

Response:

Please refer to the response to ICG IR 1.36.1

42.2 Please provide a table similar to Table C5-2 for each year from 2008-2012.

Response:

Please refer to the response to ICG IR 1.36.1

43.0 Reference: Exhibit B-1, Page 57, Line 1, Table B6-6 B6-7, C5-1, and C5-2

Preamble: In line 1 of page 57, FBI provides its formula for Capital. The Capital for year “t” is based on growth in customers from the previous year. In Schedule C5-2, FBC includes sustainment capital and growth capital. The BCPSO requires information to understand how growth in customers impacts sustainment capital.

43.1 Please confirm that sustainment capital is to maintain the existing system. If not confirmed, please fully explain.

<u>Response:</u>

Confirmed. Sustainment capital is required to maintain the safety and reliability of the electrical system and to extend and maximize the lifespan of equipment.

43.2 Please fully explain why growth in average customers should be a factor in sustainment capital.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.21.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Sustainment capital includes the installation of system capacity improvements. System capacity improvements are required when a significant number of additional customers connect to the system and the forecasted load will be too high to provide adequate power supply to all customers and generally take the form of the installation of additional lines in parallel with the existing lines. Thus, customer growth within a utility system drives the need for system capacity improvements and sustainment capital expenditures. For a discussion of the difference between sustainment and growth capital please refer to the response to BCPSO IR 1.42.3.

43.3 Please fully explain why the growth capital component should be increased by a customer component.

Response:

Please refer to the response to BCUC IR 1.27.1.

44.0 Reference: Exhibit B-1, Section B-6.3.2

Preamble: In Section B-6.3.2 of its Application, FBC discusses Flow-Through Expenses. There are

- Interest Expense
- Return on Equity
- Taxes
- Pension and OPEB Expenses and Insurance Costs
- Power Purchase Expense
- Revenues
- Depreciation and Amortization
- Rate Base other than Gas Plant in Service (from Capital Expenditures)

The BCPSO requires an understanding of the changes in flow through costs and the impact on the PBR plan

44.1 Please identify and fully discuss all changes in the proposed flow through items from the currently approved deferral accounts.

Response:

FBC refers to flow through items as those being outside of the PBR formulas, for which forecast costs are updated, or "flowed through" to customers during the term of the PBR Plan. These may include cost accounts (such as Pension/OPEB Expense) which will be trued up to actual by way of deferral accounts, or items (such as Working Capital in Rate Base) which are reforecast at the Annual Review for rate setting purposes but not trued up to actuals. Thus, not all of the items identified in Section B6.3.2 are associated with deferral accounts.

Section D4, beginning on page 258 of the Application discusses all of the deferral accounts, including proposed new accounts, changes to the amortization period or content of existing accounts, information updates of existing accounts, accounts to be discontinued and non-rate base deferral accounts.

Section D4.8 and Table D4-4 on page 274 of the Application provides a Summary of Approvals Sought regarding Deferral Accounts as well as cross references to the Sections of the Application where relevant.

44.2 In Table 6-4 FBC add OPEB cost to O&M that is then adjusted by the PBR formula. Pension and OPEB Expenses and Insurance Costs are afforded deferral treatment. Please fully explain why, given that pension costs are afforded deferral treatment, there should be an amount added to O&M for pension costs to arrive at the 2013 base O&M.

Response:

FBC has included the amounts that were captured in deferral accounts for Pension/OPEB and Insurance in the 2013 Base (to have an appropriate "base" for the 2014 through 2018 forecasts). This results in the full amount of pension/OPEB and insurance costs being included in the 2013 Base as a starting point.

In Table B6-5: Forecast O&M Formula Results on Page 53 of the Application the 2013 total Pension/OPEB and Insurance (second and third lines of the table) are then removed from the 2013 Base O&M to arrive at the 2013 Base amount that will be subject to the PBR formula.

Starting in 2014, the O&M that is subject to the formula is then escalated, and the full amount of Pension/OPEBs and Insurance is then added back to the formulaic determination of O&M in order to arrive at total O&M under PBR to be used to set the delivery rates. This demonstrates the intended treatment that non-controllable items not be subject to the I-X formula, but rather included on a forecast basis in Total O&M for rate setting purposes. Note that the amounts shown in Table B6-5 for Pension/OPEB and Insurance are forecasts at this point in time and will be updated each year as part of the Annual Review process.

45.0 Reference: Exhibit B-1, Section B-6.3.3, Exogenous Adjustments

Preamble: In Section B-6.3.3 of its Application, FBC discusses its proposal for exogenous adjustments. The BCPSO requires information to better understand the FBCI proposal.

45.1 Please confirm that FBC has not proposed a materiality limit for exogenous adjustments. If not confirmed, please provide the materiality limit and a reference to where it is proposed.

Response:

Confirmed.

45.2 Please provide the FBC recommendation for a materiality limit for exogenous adjustments.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.23.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC recommends no materiality provision on the exogenous factor adjustments. FBC and B&V believe that placing a materiality limit is most likely to deny prudent cost recovery and thus increase the underlying risk. The cost increases or decreases arising from exogenous factors are non-controllable costs that would be subject to recovery in rates under cost of service-based ratemaking without any materiality threshold. The appropriate mitigation of this risk is to not set a limit on recovery.

46.0 Reference: Exhibit B-1, Tab B, page 63 (line 31)

46.1 If approved, will FortisBC's current application for Stepped and Standby Rates for Transmission Customers give rise to the need for a Z-Factor adjustment? If yes, please explain why.

<u>Response:</u>

As discussed in section 6.3.2 of the Application on page 62 at lines 24 to 26:

> *"The majority of variances in sales revenue are attributable to weather-related load variances, customer usage rate variances and customer count load variances which are not under the control of FBC."*

Further, as discussed in the FBC Stepped and Stand-By Rates for Transmission Voltage Customers proceeding response to BCUC IR 1.3.1 any forecast-actual variances will be aggregated into an established deferral account:

> *…However, revenue variances resulting from the implementation of conservation rates as well as all other revenue variances are captured in the Revenue Variance Deferral Account approved by the Commission by Order G-110-12 and therefore, as long as this mechanism remains in place, it does not constitute a short-term risk of not collecting the revenue requirement.*

These revenue variances of the of Stepped and Stand-by Rates for Transmission Voltage Customers will be captured in an existing deferral account mechanism and will be flowed through as per the approved deferral account recovery. This approved treatment is similar to Z-factor treatment but since it is already in place a separate Z-factor application would not be required.

47.0 Reference: Exhibit B-1, Section B-6.4, Earnings Sharing Mechanism

Preamble: In Section B-6.4 of its Application, FBC discusses its earnings sharing mechanism. The BCPSO requires information to better understand the FBC proposal.

47.1 Please confirm that FBC has not proposed a dead band for earnings sharing. If not confirmed, please provide the dead band and a reference to where it is proposed.

Response:

Confirmed.

47.2 Please provide the FBC recommendation for a dead band for earnings sharing.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.24.2. This response is similar to the FEI response to that IR.

FBC is not proposing a dead-band for its earnings sharing mechanism. A dead-band would mean that all savings within the band flow to the Company, not customers, during the PBR period (i.e. until rebasing occurs at the end of the period). Under FBC's proposal with no dead-band, customers benefit immediately under the ESM, and then continue to benefit through rebasing. In other words, customers stand to benefit more.

FBC believes that a dead-band would increase the administrative and regulatory burden required to review, approve and maintain the amount of the shared earnings. Based on FBC's positive experience with the earnings sharing mechanism in the 2007 PBR (which was also designed with no dead-band) and the PBR guiding principles (see page 39 of the Application, particularly principle number 5 regarding sharing benefits) an ESM with no dead-band can best achieve the PBR design objectives.

48.0 Reference: Exhibit B-1, Section B-6.5, Efficiency Carry-Over Mechanism (ECM)

Preamble: In Section B-6.5 of its Application, FBC discusses is proposed Efficiency Carry-Over Mechanism for the end of the PBR term. As FBC has proposed that there be an ECM at the end of the PBR term, the BCPSO requires an understanding of how efficiencies achieved under Cost of Service (COS) will be accrued to customers.

48.1 Please confirm that it is FBC's view that, if customers pay the cost of projects that result in financial benefits, such as reduced costs, the benefits should be reflected in customer rates, and not shareholder returns. If not confirmed, please fully explain.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.25.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Customers do not pay the costs of projects, except in certain cases where a contribution-in-aid-of-construction is required for a specific project. However, FBC agrees that the regulatory compact would suggest that net benefits of capital projects that produce O&M savings would be reflected in customer rates upon rebasing, while the Company earns a fair return on its invested capital.

This fundamental relationship is still true whether under cost of service regulation or under PBR. O&M and capital are rebased at the conclusion of a PBR to ensure the long term benefits of the savings go to customers. Customers achieve greater benefits in the long term under PBR than under traditional cost of service regulation because the PBR effectively delays rebasing to incent the utility to invest more to achieve new cost savings, efficiencies and/or new revenues. In the meantime, customers get the benefit through earnings sharing.

48.2 The BCPSO notes that, in Table B6-4, FBC identifies Sustainable Savings as an adjustment to O&M costs. Please fully provide a summary of all savings generated in the previous COS regime, whether FBC considers the savings sustainable or not. In the response, please provide a complete description of the savings and an explanation of why FBC considers the savings sustainable or not.

Response:

The following table provides a summary of O&M savings generated in the most recent COS regime which covers 2012 through 2013 (with 2013 savings being provided on a forecast basis). Please note that of the $1.3 million of savings in 2012 was primarily due to the delayed Decision that was issued in August of that year (refer to Tab C Section 4 page 112) and the $0.5 million in 2013 of sustainable savings is being flowed through to the 2013 O&M Base to determine the amount of O&M for the 2014-2018 PBR period (refer to Tab C Section 4 page 112 and 113).

O&M ($000's)	2012 Actual	2013 Projected
Approved	54,843	57,621
Actual/Projected	53,542	57,169
Savings	**1,301**	**452**

48.3 Please fully explain how the inclusion of O&M savings in the ECM is not a double counting of the Earnings Sharing Mechanism.

Response:

This question is the same as FEI's 2014-2018 PBR Application, BCPSO IR 1.25.3. This response is the same as the FEI response to that IR, with the exception of the name change to FBC, as well as some minor differences that were necessary in order to respond appropriately for FBC.

The inclusion of O&M savings in the ECM is not a double counting of the Earnings Sharing Mechanism because the O&M benefit in the ECM (as well as the capital benefit) only affects customer rates after the end of the PBR term. This is illustrated in Appendix D5 of the Application on page 3. Line 28 of the table on page 3 indicates that rate adjustments for the ECM are permitted only after the end of the PBR five-year term.

The ECM is structured to provide the same incentive for FBC to pursue O&M and capital savings in each year of the PBR term. With the ECM, customers benefit through 50/50 sharing of the O&M and capital efficiency savings achieved for a five-year period regardless of when in the PBR term they are achieved, and then receive 100% of the savings in the longer term as the yearly ECM benefits lapse successively.

48.4 Please fully explain why, given that FBC includes incremental capital expenditures based on its formula in rates, that there is any need for an ECM.

Response:

This question is the same as FEI's 2014-2018 PBR Application, BCPSO IR 1.25.4. This response is the same as the FEI response to that IR, with the exception of the name change to FBC.

Customers benefit during the term of the PBR from capital savings achieved through the X factor, and through the earnings sharing mechanism. After the end of the PBR term, customers benefit as these savings are rebased in opening rate base.

There is no mutual exclusivity between including savings associated with lower capital expenditures based on the PBR formula in rates and the implementation of an ECM. In other words, the ECM is a complementary mechanism to the PBR plan that does not contradict any other PBR plan elements.

The ECM is designed to provide the same level of motivation for FBC to pursue both capital and O&M savings throughout the five-year PBR term. Customers receive long term benefits when the efficiencies and savings achieved by FBC are fully rebased in rates.

Since O&M and capital will be rebased to actual levels after the end of the PBR term, without an ECM there will be a diminishing incentive with each passing year for FBC to pursue further savings. The proposed ECM resolves this dilemma by ensuring that incremental savings and efficiencies achieved in the fourth or fifth year will provide the same incentive to the utility as those in the first year. Better long term benefits accrue to customers as the savings and efficiencies achieved throughout the full PBR term are rebased in rates going forward.

49.0 Reference: Exhibit B-1, Tab B, pages 68-69

49.1 Does FortisBC's Corporate Balanced Scorecard (per page 18) include targets for customer satisfaction and reliability?

Response:

Yes, FBC's current scorecard includes targets for customer satisfaction and reliability.

Please refer to the response to BCPSO 1.49.1.1 for the 2011 and 2012 customer satisfaction and reliability measures results and targets.

49.1.1 If yes, what were the "targets" for 2011 and 2012 and what were the actual results for each year?

Response:

Customer Satisfaction is measured as customers' overall satisfaction with the company, accuracy of meter reading, energy conservation information, contact centre performance and field services. The 2011 CSI results were 8.7 compared to the target performance level of 8.5. For 2012, CSI results were 8.4 compared to the target of 8.5.

Reliability is measured by the SAIDI indicator which represents the reliability of the power system in terms of outage duration (hours per customer) for all outages greater than one minute. The 2011 SAIDI results were 1.86 compared to the target performance level of 2.40. For 2012, SAIDI results were 1.95 compared to the target of 2.33.

50.0 Reference: Exhibit B-1, Section B-6.7.2, Off Ramps

Preamble: In Section B-6.7.2 of its Application, FBC indicates an off ramp if ROE exceeds or drops below the authorized ROE by 200 basis points. The BCPSO requires information to understand the proposed off ramps.

50.1 Please fully explain whether the ROE used for determination of off ramps is before or after earnings sharing.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.27.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

The ROE used for the determination of the off-ramp is after earnings sharing. This is explained in Section B6.7.2.1 of the Application:

> *"FBC is proposing that the PBR Plan be reviewed if the* ***post-sharing achieved ROE*** *of the Company exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term."*

FBC's 2007 PBR Plan did not contain an off-ramp.

50.2 Please provide the actual and authorized ROE for FBC for each of 2008-2012.

<u>Response:</u>

Please refer to the table below which provides the actual and allowed ROEs for FBC from 2008 through 2012.

	FBC	
	Allowed ROE	**Achieved ROE**
2008	9.02%	9.28%
2009	8.87%	9.41%
2010	9.90%	9.65%
2011	9.90%	10.67%
2012	9.90%	10.52%

51.0 Reference: Exhibit B-1-1, Appendix D-1

Preamble: In Appendix D-1 of its Application, FBC provides a Black and Veach (B&V) regarding PBR in other jurisdictions.

51.1 On page 2 of Appendix D-1, B&V provide the five principles of the Alberta Utilities Commission regarding PBR. Please fully explain whether B&V agrees with each of these principles. To the extent B&V agrees with the AUC principles, please explain how the FBC PBR plan meets or satisfies these principles.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.28.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V provides the following response.

Please refer to the response to BCUC IR 1.2.2. There is also a discussion of these issues in Appendix D-1 pages 45-47. B&V believes that all of the general principles and objectives that have been articulated in testimony, reports and academic literature are relevant to and inform the discussion of any PBR Plan. We also believe that the principles articulated by FBC represent the most complete set of standards for assessing the FBC plan because they address the specifics of the fourth AUC principle related to unique characteristics and circumstances of FBC. Having said all of this the goal of the FBC plan in our view was to satisfy the principles articulated in the testimony supporting the Plan as filed. With respect to the AUC Principles, B&V offers the following comments:

- **Principle 1**: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

  <u>Comment:</u> The AUC correctly recognizes that even a comprehensive PBR Plan cannot match the efficiency of a competitive market. Having recognized that goal, B&V believes that the principle offers a reasonable basis for assessment of the plan elements but care must be taken to strike a balance with other plan objectives such as Principle 2.

- **Principle 2**: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

  <u>Comment:</u> This is a fundamental principle of regulation and any form of regulatory policy - PBR or Cost of Service - must meet this principle.

- **Principle 3**: A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

  Comment: This principle is a useful concept and reasonable principle. It is possibly a fundamental benefit of PBR over cost of service regulation when coupled with the potential for productivity improvements and a lower rate trajectory.

- **Principle 4**: A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

  Comment: This principle requires that plans be customized on a variety of dimensions. The AUC did not follow this principle in adopting a single plan for gas and electric utilities and only provided a single accommodation through the use of a different cap - revenue or price - for the two industries subject to the plan.

- **Principle 5**: Customers and the regulated companies should share the benefits of a PBR plan.

  Comment: This is only a partial description of the fundamental principle related to stakeholders. The AUC did not follow this principle except in a limited sense because the AUC did not adopt earnings sharing so the only benefit to customers during the period of the plan was the stretch factor.

B&V notes that in terms of the AUC principles the FBC PBR Plan more closely satisfies these principles from the AUC than does the plans the AUC adopted. FBC's successful prior PBR experience is a factor that facilitates modifications that improve the overall scope of the Plan.

51.2 Please fully explain whether FBC agrees with the five principles of the AUC.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCPSO IR 1.28.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

FBC agrees with the essence of the AUC's five principles as discussed in the response to BCPSO IR 1.51.1. FBC believes that its proposed principles are the most complete set of standards for assessing FBC's PBR plan and are applicable in practice.

52.0 Reference: Exhibit B-1, Section D1, Financing and Return on Equity

52.1 Please provide a table similar to Table D1-1 that contains actual 2010-2012 average 30 year Government of Canada for each year, the indicative spread for each year, and the actual FBC issues of long term debt for each year.

Response:

Please refer to the table below:

Long-term Debt Actual Rates				
	Annual Averages			Actual Issues
	2010	2011	2012	19-Nov-10
30 YR GOC	3.78%	3.32%	2.45%	3.62%
Indicative Spread	1.57%	1.50%	1.53%	1.39%
New Issue Rate	**5.35%**	**4.81%**	**3.98%**	**5.01%**

52.2 On page 234, line 12, FBC indicates that forecasts are based on available projections from Canadian Chartered Banks. In Exhibit B-1-1, Appendix E, Forecasting Data, FBC provides Short Term Interest Rate Reports from BNS. TD, CIBC, Royal Bank, BMO, and NB. Only the reports from BNS, CIBC, and Royal Bank include 30 year information. Please provide the source for the forecast 30 year Government of Canada Bonds.

Response:

Please refer to Attachment 52.2 for the reports of TD, BMO and NBF:

- TD 30 Year GOC Forecast
- NBF 30 Year GOC Forecast
- Email correspondence with BMO Capital Markets

53.0 Reference: Exhibit B-1-1, Appendix D6, page 1 (lines 4-5); page 1 (line 20) to page 2 (line 5); page 5 (lines 9-11); page 6 (lines 1-2); page 6 (lines 28-29); and page 7 (line 20)

53.1 Has FortisBC undertaken any customer research to determine whether its electricity customers consider the proposed benchmarks to represent an "acceptable level of service at an acceptable level of cost"?

Response:

No customer research was undertaken to validate the proposed SQIs. Rather, FBC proposes a suite of SQIs that build on previous PBR experience. FBC believes the recommended SQIs represent refinements that ensure the interests of customers are well protected.

53.2 For those measures (e.g. Billing Index) where the proposal is to use the same target as for the gas utility, has FortisBC undertaken any customer research to determine whether its gas customers consider the benchmark to represent an "acceptable level of service at an acceptable level of cost"

Response:

No, FBC did not believe it was necessary to conduct customer research to determine whether gas customers consider the proposed benchmark of 5.0 for the Billing Index measure "an acceptable level of service at an acceptable cost".

The benchmark of 5.0 has been used for a number of years and was previously accepted by stakeholders and the Commission as part of FEI's suite of service quality indicators for its 2004 – 2009 PBR Plan. During the term of the 2004 – 2009 PBR, annual actual results were generally consistent with the 5.0 benchmark. Additionally, recent years' actual results from 2010-2012 were also consistent with the benchmark, providing confirmation of the benchmark's appropriateness for the overall level of approved O&M funding for FortisBC.

54.0 Reference: Exhibit B-1-1, Appendix D6, pages 8-9

Exhibit B-1, Tab A, page 18

54.1 It is noted that system reliability is included as one of the two "customer measures" on FortisBC's corporate scorecard (Exhibit B-1, page 18). For purposes of the corporate scorecard what specific reliability measures are used (e.g. SAIDI), what were the target/benchmark values for 2011 and 2012 and what were the 2011 and 2012 results?

<u>Response:</u>

For the purposes of the scorecard, the SAIDI indicator was included as a reliability measure.

Please refer to the response to BCPSO IR 1.49.1.1 for SAIDI targets/results for 2011 and 2012.

54.2 Please explain more fully why system reliability indicators should only be included as "an informational service quality indicator with no benchmark" for purposes of the PBR plan.

<u>Response:</u>

Please refer to the response to BCUC IR 1.68.9.

55.0 Reference: Exhibit B-1-1, Appendix D6, pages 9-10

Exhibit B-1, Tab A, page 18

55.1 It is noted that the All Injury Frequency Rate (AIFR) is included as the "safety measure" on FortisBC's corporate scorecard (Exhibit B-1, page 18). For purposes of the corporate scorecard what were the target/benchmark values for 2011 and 2012 and the actual results?

<u>Response:</u>

In 2012, the AIFR results were 1.72 compared to the target of 1.54. In 2011, the AFIR results were 1.48 compared to the target of 2.00.

55.2 Please explain more fully why AIFR) should only be included as "an informational service quality indicator" for purposes of the PBR plan.

<u>Response:</u>

AIFR can be influenced by events beyond the control of and external to company operations. As such, setting a benchmark / target for comparison is inappropriate.

56.0 Reference: Exhibit B-1-1, Appendix D6, pages 10-12

Exhibit B-1, Tab A, page 18

56.1 It is noted that the customer satisfaction index score is included as one of the two "customer measures" on FortisBC's corporate scorecard (Exhibit B-1, page 18). For purposes of the corporate scorecard what were the target/benchmark values for 2011 and 2012 and the actual results?

<u>Response:</u>

Please refer to the response to BCPSO IR 1.49.1.1.

56.2 Please explain more fully why the customer satisfaction index score should only be used as "a directional indicator" for purposes of the PBR plan.

<u>Response:</u>

As indicated on page 10 of the Service Quality Indicators report included in the Appendices of Exhibit B-1-1, FBC believes that the customer satisfaction results should be viewed as informational in nature because customer attitudes are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages, media coverage and customer concerns about tiered electricity prices or collection policies. As a result, trend information is more valuable and useful than the results at a single point in time.

57.0 Reference: Exhibit B-1-1, Appendix D6, pages 12 - 13

57.1 Please provide explanations as to why each of the SQI's FortisBC is proposing to discontinue are considered to provide "limited value going forward".

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.60.1.2 and 1.67.1.

58.0 Reference: Exhibit B-1-1, Appendix D6, pages 4-5

FortisBC's AMI CPCN Application, Exhibit B-1, pages 101-102

58.1 One of the future benefits attributed to FortisBC's AMI project was improved restoration times after an outage. Given this expected result, please explain why it is appropriate to "retain the existing benchmark of 85% for the term of the PBR"?

<u>Response:</u>

Please refer to the response to BCUC IR 1.62.1.

59.0 Reference: Exhibit B-1-1, Appendix D6, pages 6-7

59.1 Does the implementation of AMI have any impact on any of the three billing sub-measures that go into the determination of the Billing Index?

Response:

Please refer to the response to BCUC IR 1.64.1.

59.2 If yes, which billing sub-measures are impacted and how?

Response:

Please refer to the response to BCUC IR 1.64.1.

59.3 If yes, please explain why it is appropriate to use the same target as for the gas utility – which does not have AMI.

Response:

Please refer to the response to BCUC IR 1.64.1.

60.0 Reference: Exhibit B-1-1, Appendix D6, page 7

FortisBC's AMI CPCN Application, BCUC Decision, pages 77 and 88

60.1 One of the major benefits attributed to FortisBC's AMI project is the reduction in power losses (i.e., reduction in power theft). Why shouldn't loss reduction over the 2014-2018 period be used as a performance measure for purposes of PBR?

Response:

Until the Advanced Metering Infrastructure project is fully deployed, FBC considers that any loss reduction performance measure or benchmark would be premature.

System losses are presently estimated by subtracting the total energy delivered to customers (as recorded by customer billing meters) from the total energy supplied into the electric system (by Company generation resources and inter-utility imports). The difference in these two quantities represents energy which has not been accounted for through customer bills. This unaccounted energy consists of:

- Technical losses (electric energy converted primarily to heat as it passes through electrical equipment);
- Company-use load (electricity necessary to operate substation and generating facility equipment);
- Unbilled customer load (such as street lighting and cable television amplifiers);
- Meter inaccuracies; and
- Energy theft.

Since customers are on different read cycles and hence billing meters are read at different times over a multiple-month period, it is not possible to capture a "snapshot" of the total system consumption. Consequently it is not currently possible to accurately determine system losses for any specific point in time. The time-synchronized meter readings provided by AMI deployment will enable the accurate and timely collection of more granular information on system losses.

Although it will be possible to measure total system losses with improved accuracy one year after the AMI system is fully deployed (at the end of 2016), there will still be difficulties in determining how measured losses should be apportioned between technical and non-technical losses. Further, losses vary with system loads. That is, higher loadings on transformers increase losses above the core losses. This means that loss factors will vary with weather and seasonal loading. Given these difficulties, as well as the fact that SQI metrics are intended to measure service quality and not rate reductions such as those related to decreases in system losses, FBC does not believe it would be appropriate to include system loss reductions as part of the proposed service quality indicators.

60.2 If the BCUC was to include loss reduction as one of the PBR performance measures, please provide FortisBC's views as to what would be the appropriate benchmark(s) and why.

Response:

Please refer to the response to BCPSO IR 1.60.1.

61.0 Reference: Exhibit B-1-1, Appendix H, Attachment H1, pages 4 and 14

61.1 Why shouldn't FortisBC's planned 2014-2018 DSM savings be included as one of the performance measures for purposes of PBR?

Response:

FBC believes, as part of its proposed 2014 – 2018 DSM Plan included in Appendix H of Exhibit B-1, there are adequate processes to measure and report on the performance of DSM activities.

DSM savings are difficult to predict and are subject to influences outside of the Company's control, such as regulatory changes (mandating improved energy efficiency standards), free-ridership changes (as identified through the monitoring and evaluation plan), third party incentive changes (such as LiveSmartBC) and economic conditions (which can affect program participation). Importantly, demographic factors impact DSM savings in unpredictable ways. These factors include the number and age distribution of occupants in a residential dwelling, whether the dwelling is owned or rented, the age of the dwelling, the age and number of the appliances in the dwelling are just some factors. All these factors make the use of performance measures problematic and inappropriate.

62.0 Reference: Exhibit B-1, Tab C, page 80 (lines 17-20)

Exhibit B-1-1, Appendix E2, page 9 (lines 6-8)

62.1 The text from the main Application (page 80) suggests that the "savings" adjustment includes incremental DSM savings after 2012 (i.e. DSM savings over and above what's already embedded in historical loads). However, the text in Appendix E2 appears to suggest that the DSM savings relate to DSM impacts up to 2012. Please reconcile and clarify which is correct.

Response:

There are typographical errors in line 6, p. 9, Appendix E2. It should read "Before-saving load includes DSM impacts up to 2012, but without incremental DSM savings from 2013 on". In other words, the DSM to be subtracted is the incremental DSM introduced after 2012. The text on page 80 of the main Application is correct.

63.0 Reference: Exhibit B-1, Tab C, pages 82-84 and Tab D, page 261

Exhibit B-1-1, Appendix E2, page 12 and page 22

63.1 Please provide a schedule that breaks down "savings" in the without CoK Residential forecast for 2013-2018 as between i) DSM, ii) RCR, iii) CIP, iv) Rate-driven savings and v) the AMI offset.

Response:

Savings without CoK (in GWh) are broken down as follows.

	2013	2014	2015	2016	2017	2018
Net DSM	16.3	36.1	47.2	58.2	69.1	79.8
Residential	5.5	12.3	16.2	20.1	23.9	27.7
Commercial	5.7	12.6	16.4	20.2	23.9	27.6
Wholesale	3.5	7.8	10.2	12.6	14.9	17.2
Industrial	0.9	2.0	2.7	3.5	4.3	5.2
Lighting	0.4	0.8	0.8	0.8	0.8	0.8
Irrigation	0.4	0.7	0.9	1.0	1.2	1.4
RCR	0.0	2.8	7.7	12.6	17.6	22.8
CIP	0.0	0.0	1.9	3.9	3.9	3.9
Rate-driven	6.5	9.2	9.3	9.4	9.5	9.6
AMI Sale Increase	-2.9	-5.6	-9.1	-12.9	-18.2	-21.2
Total Savings	19.9	42.5	57.0	71.1	81.9	94.9

63.2 Please reconcile the DSM savings with the DSM Plan forecast set out in Appendix H.

Response:

Please refer to the responses to BCUC IR 1.80.1 through BCUC IR 1.80.4.

63.3 Please reconcile the AMI offset with the evidence provided in AMI CPCN Application proceeding.

Response:

The AMI offset in the 2014-2018 PBR Plan consists of two components with offsetting impacts on the load forecast.

The increased sales recovery from paying illegal "grow-op" sites as detailed in Table E2-22 on page 23 of Appendix E2, (Exhibit B-1-1) is reconciled with the AMI Application Exhibit B-1-3, Row 24 –Row 11 in the following table:

AMI Savings (with COK)

	2012	2013	2014	2015	2016	2017	2018
Change in paying sites	0	21	41	68	96	136	158
151,200							
AMI CPCN Sales (GWhs)	0.0	3.2	6.3	10.2	14.6	20.5	23.9

Note: Annual KWhs per site @151,200

The reduction in total illegal "grow-op" sites as a result of AMI deployment is reflected as a reduction in losses and detailed as the net of After Savings Losses and After Savings without AMI Losses in Figure C1-12 page 90, (Exhibit B-1). These figures are reconciled with the AMI Application (Exhibit B-1-3), Row 10-Row 23 (with allowances for rounding) in the following table:

AMI Loss Reduction(with COK)

	2012	2013	2014	2015	2016	2017	2018
Change in total sites	0	-9	-19	-29	-39	-49	-60
151,200							
AMI CPCN Loss reduction (GWhs)	0.0	-1.4	-2.8	-4.3	-5.9	-7.4	-9.1
After Savings without AMI Losses	0	280	281	282	284	285	286
After Savings Losses	0	278	278	278	278	277	277
Loss Reduction by AMI		2	3	4	6	8	9

Note: Annual KWhs per site @151,200

63.4 What is the basis for the CIP savings?

Response:

The Customer Information Portal (CIP) savings are based on the BC Hydro Smart Metering & Infrastructure Program Business Case (included in the AMI CPCN filing as Exhibit B-1 Appendix C-4), where it states "website-based energy savings are 2 per cent, with 15 per cent penetration of residential customers".

63.5 Please reconcile the 5.9% annual average rate increase referenced in Appendix E2 with the 3.3% annual average rate increase referenced in Tab D, page 261. In doing so please set out the derivation of both values.

Response:

The reference to a 5.9 percent annual rate increase in Appendix E2 is incorrect. The correct value is 3.3 percent, and has been corrected in Errata No. 2.

63.6 With respect the calculation of the 0.3% impact due to average rate increases, please confirm that the -0.05 elasticity assumption made by BC Hydro was with respect to nominal price changes as opposed to real price changes (i.e., after allowing for inflation).

Response:

Not confirmed. Appendix E in BC Hydro LTAP 2008, cited as a reference for price elasticity on footnote 8, page 22, Appendix E2, indicates that the -0.05 elasticity assumption was made with respect to real price changes.

63.7 Please provide the forecast RCR rates that were used to determine the RCR impact and briefly explain how the forecast was derived.

Response:

The RCR Impact is not based on a set of forecast RCR rates and no such forecast rates have been developed for that purpose. For the purpose of estimating the RCR savings, the 1.9% conservation impact from the approved option contained in the original Residential Inclining

Block Application has been used. The impact is assumed to be fully realized by 2019 and has been apportioned to the years in question.

64.0 Reference: Exhibit B-1, Tab C, pages 84-85

Exhibit B-1-1, Appendix E2, page 14

64.1 Please provide a schedule that breaks down "savings" in the without CoK Commercial forecast for 2013-2018 as between i) DSM and ii) Rate-driven savings.

Response:

The table below breaks down the DSM and rate-driven savings for the commercial class without the CoK. The DSM and rate-driven saving are subtracted from the before-savings forecast to produce the after-savings forecast.

Commercial Before and After-Savings Load Forecast without CoK (GWh)

	2013	2014	2015	2016	2017	2018
Before-savings	704	719	735	751	763	781
Rate-driven savings	1	2	2	2	2	2
DSM	6	13	16	20	24	28
After-savings	697	705	717	728	737	751

64.2 Please reconcile the DSM savings with the DSM Plan forecast set out in Appendix H.

Response:

Please refer to the responses to BCUC IR 1.80.1 through 1.80.4.

65.0 Reference: Exhibit B-1, Tab C, pages 85-86

Exhibit B-1-1, Appendix E2, pages 17-18

65.1 What was the basis for the load forecasts for the nine former industrial customers of CoK (e.g. customer surveys, econometric modeling)?

Response:

Due to the unavailability of individual CoK load information, the CoK industrial load was forecasted as a whole. Twenty-two percent of the CoK load forecast was allocated to the industrial sector based on the CoK 2010-2012 historical load composition. For further information regarding how the CoK was forecast please refer to Exhibit B-1-1, Appendix E2, Section 3.7.

65.2 What is captured in the "Savings" forecast for the industrial class? Please provide a breakdown by component.

Response:

The savings in the industrial class include DSM and rate-driven savings. A breakdown including CoK (in GWh) is given below.

	2013	2014	2015	2016	2017	2018
DSM	0.9	2.1	2.8	3.6	4.5	5.3
Rate-driven Savings	1.6	2.4	2.5	2.5	2.6	2.6
Total	2.6	4.5	5.3	6.2	7.0	8.0

65.3 Does the industrial load forecast include any assumed impacts from FortisBC's currently proposed stepped transmission rates?

Response:

No, the industrial load forecast incorporated into the Revenue Requirement Application does not include any assumed impact from the proposed stepped rate that is currently being considered by the Commission.

65.4 How has FortisBC ensured there is no double counting of savings as between the forecasts provided by the individual industrial customers and FortisBC adjustments for "Savings"?

Response:

The Company explicitly asked the industrial customers in the load survey questionnaire if their individual load forecast included DSM or not. The survey responses allowed the Company to conclude that no double counting has occurred as none of the customer forecasts included DSM or other savings.

66.0 Reference: Exhibit B-1, Tab C, pages 86-87

Exhibit B-1-1, Appendix E2, pages 16-17

66.1 What is captured in the "Savings" forecast for the Wholesale class? Please provide a breakdown by component.

Response:

The savings in the Wholesale class include DSM and rate-driven savings. A breakdown (in GWh) is given below.

	2013	2014	2015	2016	2017	2018
DSM	3.5	7.8	10.2	12.6	14.9	17.2
Rate-driven Savings	1.4	1.7	1.8	1.8	1.8	1.8
Total	5.0	9.5	11.9	14.3	16.7	19.0

66.2 How has FortisBC ensured there is no double counting of savings as between the forecasts provided by the individual wholesale customers and FortisBC adjustments for "Savings"?

Response:

The Company explicitly asked the Wholesale customers in the load survey questionnaire if their individual load forecast included DSM. It was confirmed that there was no double counting of savings as none of the customers' forecasts included DSM or other savings.

67.0 Reference: Exhibit B-1-1, Appendix E2, pages 20-21

67.1 Please break down the total "Savings" forecast for 2013-2018 for CoK into it various components (i.e. DSM, Rate-driven, AMI, RCR, CIP).

Response:

A saving breakdown for CoK (in GWh) is provided below.

	2013	2014	2015	2016	2017	2018
DSM	0.8	1.8	2.3	2.9	3.4	4.0
Residential	0.3	0.8	1.0	1.2	1.5	1.7
Commercial	0.4	0.9	1.2	1.5	1.8	2.1
Industrial	0.0	0.1	0.1	0.1	0.1	0.2
RCR	0.0	0.3	0.9	1.5	2.1	2.7
CIP	0.0	0.0	0.2	0.5	0.5	0.5
Rate-driven	0.7	1.0	1.0	1.0	1.0	1.0
AMI Sale Increase	-0.4	-0.7	-1.1	-1.6	-2.3	-2.7
Total Net Saving	1.1	2.4	3.3	4.2	4.7	5.5

67.2 Are the assumed DSM savings for COK reflected in FortisBC's DSM Plan (per Appendix H)? If not, what is the basis for the forecast savings?

Response:

Yes, the CoK plan DSM savings are included in FBC's 2014-18 DSM Plan.

67.3 Does the COK forecast capture the Rate-driven impact of CoK's customers transferring from CoK's rates to FortisBC's rates in 2013?

Response:

The current forecast assumes the same rate-impact savings at 0.2% of before-saving load for both CoK and other FBC customers. There is no special adjustment for the CoK customers in 2013.

67.4 With respect to page 21 (line 6), please confirm that the statement "CoK integration does not result in any change in the net load" applies to the load forecast prior to Savings.

Response:

This statement should read: "CoK integration does not result in any change in the **gross** load". Please refer to the response to BCPSO IR 1.79.5 for further explanation.

The corrected statement is applied to both before and after savings forecasts. The CoK integration merely allocates CoK gross load from the Wholesale class to the Residential, Commercial, and Industrial classes.

67.5 With respect to page 21 (line 6), please confirm that the statement "CoK integration does not result in any change in the net load" does not account for the fact that losses on the CoK system will now be part of FortisBC's losses and excluded from net load whereas previously they would have been included in CoK's contribution to net load.

Response:

Confirmed. The statement should read "The CoK integration does not result in any change in the gross load."

68.0 Reference: Exhibit B-1, Tab C, page 89

68.1 Based on the theft reduction assumptions as adopted by the BCUC in its Decision regarding FortisBC's AMI CPCN application how would the current 8% loss factor change over the 2014-2018 period?

<u>Response:</u>

The 8% losses are before the AMI loss reduction. The loss reduction due to the AMI project (in GWh) can be obtained by subtracting the loss after the AMI loss reduction line from the loss before the AMI loss reduction line in Figure C1-12 with the result as follows:

	2013	2014	2015	2016	2017	2018
AMI Loss Reduction (GWh)	1.4	2.8	4.3	5.9	7.4	9.1
Gross Loss Rate without AMI Loss Reduction	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Gross Loss Rate with AMI Loss Reduction	7.96%	7.91%	7.86%	7.82%	7.76%	7.71%

The GWh numbers in the table above are also the numbers supplied in the AMI CPCN application (please refer to the response to BCPSO IR 1.63.3).

69.0 Reference: Exhibit B-1, Tab C, pages 101 and 106

69.1 Please provide revised versions of Tables C2-5 and C2-9 that set out the forecast GWh from each source over the period 2013 to 2018 and the associated unit costs for each source by year.

Response:

Tables 1, 2, and 3 show Tables C2-5 and C2-9 with the associated unit cost for each source by year. Please note that the each source provides a different combination of capacity and energy, energy only, or capacity only. Therefore it is difficult to draw a direct comparison on a per GWh basis.

Table 1

		2013 Projection	GWh	$/MWh	2014 Forecast	GWh	$/MWh
		($000s)					
1	Brilliant	36,781	922	39.89	35,764	922	38.79
2	BC Hydro	31,021	517	60.00	37,201	663	56.11
3	Independent Power Producers	229	6	39.48	162	4	40.50
4	Market Purchases	16,094	419	38.41	15,281	306	49.94
5	Surplus Revenues	(308)	(11)	28.00	(594)	(22)	27.00
6	Special and Accounting Adjustments	14	0	0.00	0	0	0.00
7	Balancing Pool	435	12	37.35	0	0	0.00
8	TOTAL	84,266	1,864	45.20	87,814	1,873	46.88
9	Gross Load (GWh)	3,461			3,519		

Table 2

		Forecast 2015	GWh	$/MWh	Forecast 2016	GWh	$/MWh
		($000s)					
1	Brilliant	38,336	922	41.58	39,151	922	42.46
2	BC Hydro	40,660	771	52.74	48,315	916	52.75
3	Waneta Expansion	25,864	0	0.00	41,960	0	0.00
4	Independent Power Producers	165	4	41.33	169	4	42.19
5	Market and Contracted Purchases	11,822	251	47.10	5,060	123	41.14
6	Surplus Sales Revenues	-467	-17	27.48	-451	-15	30.06
7	Special and Accounting Adjustments	0	0	0.00	0	0	0.00
8	Balancing Pool	0	0	0.00	0	0	0.00
9	**TOTAL**	116,380	1,931	60.27	134,204	1,950	68.82
10	Gross Load	3,537			3,554		

Table 3

		Forecast 2017	GWh	$/MWh	Forecast 2018	GWh	$/MWh
		($000s)					
1	Brilliant	39,983	922	43.37	40,835	922	44.29
2	BC Hydro	51,287	981	52.28	55,712	1,068	52.16
3	Waneta Expansion	42,594	0	0.00	43,597	0	0.00
4	Independent Power Producers	172	4	43.04	176	4	43.93
5	Market and Contracted Purchases	3,125	75	41.67	414	9	45.97
6	Surplus Sales Revenues	-446	-14	31.84	-411	-12	34.24
7	Special and Accounting Adjustments	0	0	0.00	0		0.00
8	Balancing Pool	0	0	0.00	0		0.00
9	**TOTAL**	136,716	1,968	69.47	140,322	1,991	70.48
10	Gross Load	3,572			3,596		

69.2 What has Fortis BC used as the BC Hydro rate increases for April 1, 2014 and subsequent years for purposes of forecasting the BC Hydro PPA costs?

Response:

Please see the response to BCMEU IR 1.4.1.

70.0 Reference: Exhibit B-1, Tab C, pages 108-110

70.1 Please provide the actual Other Income for 2010 and 2011 broken down as per Table C3-1.

Response:

Please refer to the response to BCUC IR 1.227.1.

70.2 Please identify the two customers who are expected to be using FortisBC's transmission system in 2014.

Response:

The two customers are BC Hydro and Celgar.

71.0 Reference: Exhibit B-1, Tab C, page 112

71.1 In which Department was the 2013 expenditure of $1.2 M for the Mandatory Reliability Standards Program recorded?

Response:

The costs for Mandatory Reliability Standards compliance are included in the Engineering Services and Project Management budgets. The $1.2 million expenditure is over two years with $0.3 million in 2012 and $0.9 million in 2013.

71.2 Please provide a schedule that sets out the actual equivalent full time employees (FTEs) in each Department for each year from 2010 to 2012 and the forecast FTEs by Department for 2013 through 2018.

Response:

Please refer to the table below for FTEs by department for 2010-2012. Note that FTEs are not specifically tracked in FBC's system; there may be slight variations in FTEs because of reporting differences in the system year over year.

FTEs by Department from 2010-2018

Business Areas	2010	2011	2012
Corporate	8	7	7
Customer Service	64.66	69.66	70.93
Energy Solutions & External Relations	7	7	8
Energy Supply & Resource Development	7	4	7
Engineering Services & Project Management	64	58	64
Environment, Health & Safety	8	8	8
Facilities	7	4	5
Financial & Regulatory Services	24	23	27.29
Generation	96	98	76.01
Governance	2	2	3
Human Resources	14	10.33	12.12
Information Technology	27	28	26
Operations	165	174.32	187.78
Operations Support	44	34.32	40
Total	537.66	527.63	542.13

As discussed in Section C4.1, page 111 of the Application, the 2014 Forecast represents a high level forecast. FBC did not develop FTE projections for future years. The FTE levels for 2013 and for the remainder of the PBR Period are expected to be at a level similar to 2012 on a total company basis.

72.0 Reference: Exhibit B-1, Tab C, page 113, Table C4-2

72.1 Are the 2014-2018 forecasts provided in the subsequent sections for each department meant to be consistent with/build on the 2013 Base values set out in Table C4-2?

Response:

The 2014-2018 forecasts provided in the subsequent sections for each department build from the 2013 Base values set out in Table C4-2. The forecasts in Section C4 represent a high level forecast of future trends and upcoming challenges for FBC.

72.1.1 If not, what is the 2013 starting point for the individual department 2014-2018 forecasts?

Response:

Please refer to the response to BCPSO IR 1.72.1.

72.2 Please provide a schedule that sets out the total forecast O&M for each department for each year 2014-2018 as described in the subsequent subsections of the of Tab C, Section 4. Also, please reconcile the total O&M for each year with the O&M forecast values set out in Appendix G, page 1.

Response:

The table below provides the O&M forecast for each department for the years 2014-2018 as described in Tab C, Section 4 as well as the O&M per the PBR formula in Appendix G, page 1.

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Generation	$ 3,130	$ 3,217	$ 3,307	$ 3,398	$ 3,493
Operations	22,571	23,046	23,609	24,184	24,775
Customer Service	7,576	7,788	8,003	8,220	8,444
External Relations	1,525	1,561	1,598	1,636	1,674
Energy Supply	1,283	1,393	1,430	1,469	1,509
Information Technology	3,231	3,315	3,400	3,489	3,580
Engineering	3,973	4,084	4,197	4,313	4,433
Operations Support	1,291	1,325	1,360	1,396	1,431
Facilities	2,683	2,690	2,748	2,808	2,869
Environment, Health & Safety	1,043	1,072	1,104	1,135	1,168
Finance & Regulatory	4,403	4,522	4,646	4,771	4,899
Human Resources	2,009	2,062	2,116	2,172	2,228
Governance	2,691	2,783	2,875	3,032	3,069
Corporate	3,605	3,173	2,637	2,245	1,863
Advanced Metering Infrastructure	368	(439)	(2,411)	(2,369)	(2,794)
Total O&M	**$ 61,382**	**$ 61,592**	**$ 60,619**	**$ 61,899**	**$ 62,641**
PBR O&M - Appendix G Page 1	**$ 61,386**	**$ 61,744**	**$ 60,960**	**$ 62,378**	**$ 63,302**

The department view of O&M described in Tab C, Section 4 is a high level forecast of future trends and upcoming challenges for FBC that was prepared by department. The O&M in Appendix G, Page 1 has been calculated through the PBR formula which is discussed in Tab B and does not rely on the departmental O&M forecasts in Tab C. The two streams of O&M are independent of each other and cannot therefore be reconciled.

73.0 Reference: Exhibit B-1, Tab C, page 115 (lines 10-14)

73.1 What is difference between the compensation reflected in: i) "base salary and target total cash" versus ii) "target total direct"?

Response:

The difference between "target total cash" and "target total direct compensation" is the present value of long term incentive pay.

This is because "target total cash" includes base salary and target short term incentive pay, while "target total direct" compensation includes target total cash and present value of long term incentive pay.

74.0 Reference: Exhibit B-1-1, Appendix C4

74.1 For each of the related parties where costs were charge to FortisBC Inc., please identify those charges that arise as a result of an "allocation of costs" as opposed to being based on charges for specific work or services.

Response:

Related party transactions charged to FortisBC Inc. during 2012, as included in Appendix C4 - Item 3 – Related Party Operating Transactions were primarily based on charges for specific work or services with the exception of Fortis Inc. corporate services and FortisBC Holdings Inc. corporate governance costs (Board of Director costs).

As described in Section C4, Part 4.17.2.1 of the 2014-2018 PBR Application, the corporate services charged by Fortis Inc. are shared amongst the Fortis Inc. group, thereby providing economies of scale, and were reviewed by KPMG for appropriateness of allocation in Appendix F2 of the 2014-2018 PBR Application. These costs were also approved for recovery previously in the 2012-2013 RRA Decision Order G-110-12. Additionally, the non-regulated costs charged to FortisBC Inc. are excluded from regulated costs used in setting the revenue requirement.

As described in Section C4, Part 4.17.3.2 of the 2014-2018 PBR Application, the corporate governance costs charged by FortisBC Holdings Inc. relate to a shared Board of Directors and shared Board Committees between FortisBC Inc. and FortisBC Holdings Inc. These costs are shared using the Massachusetts Formula, which is used extensively in industry and were approved as an allocation method in the 2012-2013 RRA Decision Order G-110-12.

Aside from the corporate services charged by Fortis Inc. and the corporate governance costs charged by FortisBC Holdings Inc., which are both described above, certain other costs have been defined as "Allocated" if they were charged to FortisBC Inc. based on a percentage share of an underlying cost. A summary is presented below:

Transactions charged by Fortis Inc.	
Transaction Type	**Allocated / Specific**
Compensation Recoveries (Regulated)	Allocated
Compensation Recoveries (Non-Regulated)	Allocated
Corporate Governance Costs	Allocated
Consulting & Legal Costs	Allocated
Audit & Other Filing Costs	Allocated
Pension Related Recoveries	Specific
Other Recoverable Corporate Expenses	Allocated

Transactions charged by FortisAlberta	
Transaction Type	**Allocated / Specific**
Metering Services	Specific
Material & Equipment Purchase (Capital)	Specific
Employee Services	Specific
Membership Fees	Allocated
Transactions charged by Newfoundland Power	
Transaction Type	**Allocated / Specific**
Software Licenses	Specific
Labour & Travel Expenses	Specific
Share of Conference Board of Canada Subscription	Allocated
Transactions charged by FortisBC Holdings Inc.	
Transaction Type	**Allocated / Specific**
Labour & Travel Expenses	Specific
Corporate Governance Costs	Allocated
Insurance Services	Specific
Transactions charged by FortisBC Energy Inc.	
Transaction Type	**Allocated / Specific**
Labour & Travel Expenses	Specific
Rental of Springfield Road Office	Specific
Long Service Recognition Expenses	Allocated
Purchase of Natural Gas (Tariff Sales)	Specific

74.2 With respect to the $1.38 M in transactions charged by FortisBC Energy Inc. (page 11), in what areas where the labour & travel charges primarily for?

Response:

Labour and travel charged to FortisBC Inc. by FortisBC Energy Inc. during 2012 was primarily in the area of Human Resources, Communications, Information Technology, Resource Planning, Fleet Services, and Demand Side Management as well as various other departments where integrated services have taken place.

75.0 Reference: Exhibit B-1, Tab C, page 125 (lines 10-17)

75.1 How many Major Unit Inspections were carried out in each of the following years - 2010, 2011 and 2012?

Response:

No Major Unit Inspections were carried out during 2010-2012.

75.2 Please explain more fully why the $350,000 annual cost associated with Major Unit Inspections is incremental to past spending. Hasn't FortisBC been following the described "best maintenance practice" in recent years and, if not, why not?

Response:

Please refer to the responses to BCUC IR 1.111.2 and BCUC IR 1.111.3. Also, please see page 125 of the Application: "Since the initiation of the ULE program no major overhauls were completed on any of the units." Considering the annual operating hours of the units and that a major overhaul is needed approximately every 80,000 operational hours, each of the 15 units will now require major maintenance on a 15-year cycle. Therefore, the current request complies with best maintenance practices.

76.0 Reference: Exhibit B-1, Tab C, pages 138-139

76.1 Tables C4-13 and C4-14 indicates Energy Supply staffing increases in 2014 and 2015. What will be the specific responsibilities of these new staff?

<u>Response:</u>

The forecast increase in 2014 and 2015 is due to one new FTE in the energy supply group beginning in 2014. This new position will be based at the System Control Center and is required to help manage real-time power supply operations, including administration of the new PPA and related agreements with BC Hydro as discussed in Section 4.8.2 of Exhibit B-1, integration of the Waneta Expansion project, and continued work to mitigate power purchase expense. The new PPA and related agreements are complex contractual arrangements that if not properly adhered to may result in either lost opportunities to minimize costs or in direct penalty charges from BC Hydro.

The position will help to track and manage all of FBC's contractual relations and will help to train, monitor and educate FBC's real-time operators, which will result in greater efficiency in FBC's real time operations. As discussed in the Application, the power purchase expense is forecast to increase to $141 million by the end of the period, and the additional position is required and reasonable to meet our overall staffing requirements to ensure all contractual obligations are met and customers receive the full benefit of the contract flexibility and mitigation opportunities that are available.

77.0 Reference: Exhibit B-1, Tab C, pages 145 and 147

77.1 Are any of the costs set out in Table C4-18 included in the Table C4-17?

Response:

The costs shown in Table C4-17 include all costs shown in Table C4-18, but do not include the deferred MRS costs of $320,000 for 2012. The $900,000 in deferred MRS costs for 2013 is reflected in the 2013 Base, but not the 2013 Approved or the 2013 Projection as provided in Table C4-17.

77.1.1 If yes, please provide a schedule setting out the overlap.

Response:

The table below provides a breakdown of Engineering Services and Project Management costs (Other) and MRS costs, and deferred MRS costs.

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Other	$ 1,242	$ 1,347	$ 1,436	$ 1,604	$ 1,635	$ 1,717
MRS	$ -	$ 1,016	$ 1,179	$ 1,187	$ 1,188	$ 2,150
Subtotal	$ **1,242**	**$ 2,363**	**$ 2,615**	**$ 2,791**	**$ 2,822**	**$ 3,867**
Deferred	$ -	$ -	$ 320	$ -	$ 900	$ -
Total	**$ 1,242**	**$ 2,363**	**$ 2,935**	**$ 2,791**	**$ 3,723**	**$ 3,867**

77.1.2 If no, please reconcile the $320,000 in MRS costs recorded in deferral accounts in 2012 with the total reported 2012 MRS expenditures of $1.499 M.

Response:

The following table provides the requested reconciliation:

	2012 Actual ($000s)
MRS O&M	
Labour	$1,008
Non-Labour	$171
Subtotal	$1,179
Deferred MRS O&M	
Labour	$320
Non-Labour	$0
Subtotal	$320
Total	**$1,499**

77.1.3 If no, please reconcile the $900,000 in MRS cost recorded in deferral accounts in 2013 with the approved and projected total MRS costs for that year per Table C4-18.

Response:

Please refer to the response to BCPSO IR 1.77.1.1.

77.2 Do the costs set out in Table C4-19 include the MRS O&M forecast in Table C4-20?

Response:

Confirmed.

77.2.1 If not, what is the total forecast O&M costs for this department for 2014-2018?

Response:

Please refer to the response to BCPSO IR 1.77.2.1.

78.0 Reference: Exhibit B-1, Tab C, page 149, Table C4-21

78.1 From whom and for what are the "Recoveries" reported made?

Response:

Recoveries reported in Exhibit B-1, are comprised of two components:

1. Transportation Recoveries – vehicles and equipment are charged out to the appropriate projects as they are utilized on capital projects, third party or O&M.

2. Material Handling Recoveries – In order to properly reflect the cost of material from inventory, the Company includes a material handling charge to cover the full cost of warehousing. The material handling charge is therefore included in the cost of material that is charged to capital, third party or O&M activities.

79.0 Reference: Exhibit B-1, Tab C, page 166, Table C4-31

Exhibit B-1, Tab D, page 263

79.1 What types of costs (e.g. claims, premiums. FEI transfers) are included in "insurance expense" as discussed in Tab D?

Response:

Insurance expense includes premiums, asset valuations and first and third party liability costs. While insurance premiums and first and third party liability costs are uncontrollable in nature, the request for the Insurance Expense Variance Deferral Account referred to in D4.3.4 on page 263 of Section D4 of the 2014-18 PBR Application is meant to only capture variances between forecast and actual insurance premiums.

79.2 Please provide a breakdown of the 2012 actual Non-Labour costs. In particular, how much of this was insurance expense.

Response:

The breakdown of 2012 Actual Governance Non-Labour Costs, including the component related to insurance expense, has been provided in the response to BCUC IR 1.143.2.

79.3 Please confirm that the proposed 2014 rates include $1,734,000 in insurance expense and the 2014 variance to be posted in the proposed deferral account (page 263) will be calculated as the difference from this value.

Response:

The proposed 2014 rates include $1,734 thousand of insurance expense which is comprised of insurance premiums, first and third party liability costs and valuations. 2014 additions to the Insurance Variance Deferral account will consist only of differences from the forecast insurance premiums which are forecast in the amount of $1,460 thousand and are included in the $1,734 thousand overall insurance expense. Including only the variance on insurance premiums as additions to Insurance Expense Variance deferral account was stated on page 263 in Section D4, item 4.3.4 of the 2014-2018 PBR Application which states "therefore a deferral account to capture the difference between actual and forecast costs of insurance premiums is appropriate."

80.0 Reference: Exhibit B-1, Tab C, page 170 (lines 17-30)

Exhibit B-1-1, Appendix C4, page 9

80.1 Which of the transactions reported for 2012 in Appendix C4 fall into the category of Corporate Services provided by Fortis Inc.? In responding please reconcile the amounts reported in C4 with the total actual Corporate Service Fees of $1,868,000 reported in Table C4-34.

<u>Response:</u>

The non-regulated compensation recoveries, pension related recoveries, and a portion of the other recoverable corporate expenses in Appendix C4 do not fall into the category of Corporate Services provided by Fortis Inc. in Table C4-34 of the 2014-2018 PBR Application. A reconciled Appendix C4 table is provided below (in $000's).

Corporate Services charged by Fortis Inc.	
Transaction Type	**Amount ($000's)**
Compensation Recoveries (Regulated)	789
Corporate Governance Costs	479
Consulting & Legal Costs	229
Audit & Other Filing Costs	228
Other Recoverable Corporate Expenses	143
2012 Total (agrees to Table C4-34)	1,868

80.2 What are the specific corporate services provided by Fortis Inc.?

<u>Response:</u>

The specific corporate services provided by Fortis Inc are outlined in the Corporate Services Study which was included under tab F2 of the application.

81.0 Reference: Exhibit B-1, Tab C, page 174 (lines 12-13)

81.1 Please provide the cross-references to the FortisBC's AMI CPCN Application for the O&M reductions reported for each of the four departments and for the total AMI O&M impact shown in Table C4-44.

Response:

The forecast O&M reductions related to the AMI project identified in section C4.18 were not shown in the AMI CPCN application on a per department basis, but were rather identified under "Operating Expenses" on the Net AMI tab of the spreadsheet provided as Exhibit B-1-3 in that proceeding. Please see the table below which replicates the AMI O&M information provided in Exhibit B-1-3 from the AMI proceeding, which correlates with the total AMI O&M impact shown in Table C4-44 from the 2014-2018 RRA.

($000s)	2014	2015	2016	2017	2018
New Operating Costs	884	1,538	1,565	1,601	1,630
Meter Reading	-	(1,151)	(2,887)	(2,934)	(3,112)
Remote Disconnect/Reconnect	(150)	(466)	(613)	(635)	(658)
Meter Exchanges	(384)	(363)	(450)	(338)	(589)
Contact Centre	18	3	(27)	(63)	(65)
Total	**368**	**(439)**	**(2,411)**	**(2,369)**	**(2,794)**

82.0 Reference: Exhibit B-1, Tab C, pages 179 - 180

82.1 Please explain why the total approved 2013 expenditures on Major Projects as set out in Table C5-1 ($46.9 M) is different from the value set out in Table C5-2 ($54.9 M).

Response:

Please refer to the response to BCUC IR 1.150.1.1, as well as to Errata No. 2.

82.2 With respect the Major Project costs set out in Table C5-2, please indicate i) how much of the $54.9 M is associated with CPCN Applications/Approvals and ii) how much of the $54.9 M is associated with CPCN Applications/Approvals for projects in excess of $20 M.

Response:

Of the $54.9 million listed in Table C5-2 for Major Projects, approximately $35.8 million is related to CPCN applications (Kelowna Bulk Transformer Capacity Addition, Kootenay Long Term Facility, and Advanced Metering Infrastructure). Of these three CPCN projects, the Advanced Metering Infrastructure is the only project with forecast expenditures in excess of $20 million.

83.0 Reference: Exhibit B-1, Tab C, page 182 (lines 8-11)

83.1 Please why explain the 2013-2018 forecasts for O&M utilized a specific forecast for labour cost inflation (per page 116), but the forecasts for capital expenditures are based on general inflation rate (i.e. 2%).

Response:

O&M and capital expenditures will be determined by formula applied to the 2013 Base O&M and Capital. FBC notes that rates will not be set based on the O&M and capital expenditures as forecast in Application Section C. Please refer to Sections B6.2.4 and B6.2.5 of the Application.

The 2013-2018 forecasts are a high level view of the anticipated expenditures over the PBR period. FBC forecasts O&M to increase at labour inflation given the influence labour has on O&M, whereas capital is forecast at general inflation given the more diverse inputs that constitute capital. This is consistent with past forecasting practice for FBC.

84.0 Reference: Exhibit B-1, Tab C, page 188, Table C5-4

84.1 Please break out the forecast capital spending separately for Transmission, Stations and Telecommunications.

Response:

Please see the table provided below:

Sustainment Capital($000s)	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Transmission	6,317	5,687	4,037	3,547	3,950
Stations	8,559	2,814	3,365	5,408	6,284
Telecommunications	1,294	1,320	2,077	2,119	1,286
Total	**16,171**	**9,821**	**9,480**	**11,073**	**11,520**

84.2 What specific project(s) account for the one-time increase in capital spending in this area in 2014?

Response:

The increase in sustainment capital for 2014 is related to the substation portion of the PCB Environmental Compliance program. This is a continuation of PCB Environment Compliance expenditures in 2012/13 which were approved by Order G-110-12.

85.0 Reference: Exhibit B-1, Tab C, page 207, Table C5-5

85.1 Please explain why the annual forecast "growth" expenditures on Transmission, Stations and Telecommunications displays such an uneven pattern over the 2013-3018 period and why a more even pattern and associated use of resources is not possible.

<u>Response:</u>

The uneven pattern of annual forecast growth expenditures for 2013 – 2018 period is due to a number of factors. Unlike sustainment capital – which generally is driven by ongoing asset replacement needs and hence has a relatively consistent pattern over the period – growth expenditures tend to be "lumpy" as they are driven by larger, one-time projects. For example, once the capacity of a given distribution substation is exhausted, a major project to increase the station capacity may be proposed. Once that project is complete, the additional capacity is sufficient for many years. Since localized system capacity is not consumed at an even rate, growth expenditures tend to be highly variable over the years.

A portion of the forecast growth expenditures for 2014 – 2015 (approximately $2.1 million) is related to projects necessitated by the addition of the CoK distribution assets. The remaining forecast expenditures and timing of the projects identified for completion during the PBR period are the result of planning studies, construction and material delivery schedules, and availability of resources. Given the long lead times generally associated with these types of infrastructure growth projects and the nature of the projects themselves, acceleration or deferring expenditures to achieve a more even pattern of forecast expenditures is not possible.

86.0 Reference: Exhibit B-1, Tab C, pages 226-231

86.1 For each of the seven projects where FortisBC intends to file a CPCN please indicate the anticipated in-service date (i.e. what year will the costs first be included in rate base per page 55).

Response:

There are eight projects for which FortisBC intends to file a CPCN (see Exhibit B-1, Tab C, pages 226-231).

The Table below indicates a high level anticipated first in-service date projection (i.e. the year costs will first be included in rate base).

	Project Names	Year of first inclusion in Rate Base
1	Upper Bonnington Old Unit Refurbishment	2017
2	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2017
3	Kelowna Bulk Transformer Capacity Addition	2018
4	Grand Forks Transformer Addition	2017
5	New Ruckles Substation	2016
6	New Central Okanagan Station	2018
7	Grand Forks to Warfield Fibre Installation	2014
8	Kootenay Operations Centre	2016

86.2 What are the preliminary cost estimates for i) the Kootenay Long Term Facilities Strategy and ii) the Upper Bonnington Unit 1, 2, 4 Refurbishment?

Response:

The unloaded preliminary estimate for the Kootenay Long Term Facilities Strategy is $17.7 million. The unloaded preliminary estimate for the Upper Bonnington Unit 1, 2, 4 refurbishment is $20.1 million.

86.3 For those projects that do not meet the $20 M threshold, please outline why FortisBC believes a CPCN application is necessary.

Response:

With respect to the Grand Forks Transformer Addition and the Grand Forks to Warfield Fibre Installation projects, FBC was previously directed by the BCUC (G-195-10, G-110-12) to file CPCN applications for these projects.

With respect to the Kelowna Bulk Transformer Capacity Addition (KBTCA) project, and the Kootenay Long Term Facilities projects, FBC previously committed to filing CPCN applications for these projects. For the KBTCA project, preliminary estimates indicated a cost in excess of the $20 million threshold. Although this forecast cost has since been revised to less than $20 million, FBC still intends to seek a CPCN as initially planned. With regard to the Kootenay Long Term Facilities project, FBC initially intended to seek a CPCN as the project planning was forecast to fall between capital expenditure applications. Although the project has been delayed, FBC still intends to seek a CPCN as originally planned.

The remaining CPCN projects with forecast expenditures less than $20 million are both stations infrastructure projects (Ruckles Substation Upgrade, Central Okanagan Substation). Given the profile and potential public concern sometimes associated with station infrastructure projects, FBC believes a CPCN application provides the most effective mechanism to both examine and address any concerns or issues regarding these types of projects.

86.4 Please explain why CPCN projects with a low capital cost (e.g. below say $20 M or $10 M) should not be assumed to be captured under the PBR-based capital spending formula.

Response:

As the proposed PBR formula (including the determination of the 2013 Base) is intended to apply to steady-state operations, and not incremental expenditures related to large one-time projects which are typically the subject of CPCN applications, it would not be appropriate to capture CPCN projects under the proposed PBR-based capital spending formula. As noted by B&V, capital projects such as those subject to a CPCN application can impact productivity as costs may increase without any change in capacity or number of customers. As such, the exclusion of the CPCN capital is considered an appropriate means of addressing the lumpy nature of this type of capital under a PBR plan.

It should also be noted that projects subject to a CPCN application often involve significant public interest and scrutiny, which is in contrast to projects captured under the proposed PBR formula. Indeed, the CPCN application process provides an efficient and effective means of examining and addressing any concerns regarding these types of projects. As such, FBC believes its proposal to exclude CPCN capital expenditures from the PBR formula is appropriate.

87.0 Reference: Exhibit B-1, Section D2, Taxes

87.1 Please fully discuss FBI's awareness of previous income tax rulings around the treatment of indirect costs, commonly known as Rainbow or Candarel adjustments.

Response:

FBC interprets the references to "Rainbow or Candarel" as references to the following income tax cases:

1. *Canderel Ltd. v. Canada*, 1998 CarswellNat 81 (Supreme Court of Canada); and
2. *Rainbow Pipe Line Co. v. R.*, 2002 CarswellNat 1378 (Federal Court of Appeal).

FBC is aware of the framework set out in Canderel for computing income for tax purposes and in particular the analysis used for determining if and when expenditures are deductible. In addition, FBC is aware of the decision in Rainbow and the considerations to be taken into account in determining whether a particular expenditure should be capitalized or expensed for income tax purposes. These considerations are taken into account in the calculation of FBC's income for tax purposes.

Based on FBC's application of these income tax cases and Income Tax Interpretation Bulletin IT-128R - *Capital Cost Allowance – Depreciable Property*, certain costs estimated to be eligible as period deductions have been included in the forecasted 2014 income tax provision. It is also worth noting that because of the judgment involved in making the determinations of these costs that can be tracked and supported as eligible period deductions, it is always possible that the Canada Revenue Agency would take a different view than the Company in respect of the deductibility of certain expenditures.

87.2 Please fully explain any reviews, challenges, or appeals that FBC is aware of or contemplating, that would see FBC income taxes related to previously filed returns change materially.

Response:

FBC currently does not have any reviews, challenges, or appeals that it is aware of or contemplating that would change FBC income taxes related to previously filed returns. However there always exists the risk of future audits and reassessments initiated by government entities which are beyond FBC's control. These audits, reassessments or reviews could relate to reviews of past returns, subject to those that are statute barred, as well as those returns that will be filed during the term of the PBR. FBC's lack of control around the government initiation of such future audits, reassessments or reviews warrants the request for a Tax Variance Deferral Account pursuant to Section 2.4.1, page 241 of Section D2: Taxes.

88.0 Reference: Exhibit B-1, Section D3, Accounting Policies

88.1 Please explain FBC's views on whether the BCUC is bound by accounting pronouncements, such as US GAAP or IFRS, in setting regulatory accounting and reporting requirements, and in setting revenue requirement.

<u>Response:</u>

FBC has interpreted "accounting pronouncements", as used in this question, to mean a set of accounting principles, such as US GAAP or IFRS.

While the BCUC is not bound by US GAAP or IFRS, the BCUC Uniform System of Accounts alludes to rate-regulated utilities applying generally accepted accounting practices and principles. Consistent with the Uniform System of Accounts, FBC believes that the BCUC should follow the only established system of generally accepted accounting principles relevant to rate regulated utilities, which is US GAAP. The use of US GAAP for setting regulatory accounting and reporting requirements and setting revenue requirements was approved pursuant to Commission Order G-117-11 for the Fortis BC Utilities Application to Adopt US GAAP effective January 1, 2012 and further reiterated in Section D3.1 of the Application.

The adoption of US GAAP for regulatory purposes beginning in 2012 has allowed for the continuation of both transparency and comparability between regulatory and external financial reporting since US GAAP allows for regulated entities to recognize regulatory assets and liabilities under ASC 980, *Regulated Operations*, while IFRS does not currently have existing standards that permit similar treatment.

Additionally, FBC believes that the same set of accounting principles should be used for regulatory purposes as what is used for external financial reporting purposes so that the underlying economic substance of the Company's operations is appropriately reflected. If the BCUC set accounting requirements that differed from what was used to account for the same transaction for external financial reporting purposes, this would result in the Company having to maintain two sets of accounting records which would result in a significant amount of work and cost to the Company and customers and decrease the relevance of the external financial statements. Furthermore, adopting the same set of accounting principles for financial reporting and regulatory reporting will enhance both transparency and comparability between regulatory and external financial reporting.

89.0 Reference: Exhibit B-1, Section D 3.3 Depreciation Rates and Methodology

89.1 Please confirm that FBC will not change depreciation or depreciation related rates during the term of the PBR, without explicit Commission approval. If not confirmed, please fully explain.

<u>Response:</u>

Confirmed that FBC will not change depreciation rates during the term of the PBR without Commission approval. Regarding changes in depreciation rates, please refer to page 249 Section D3.3 Depreciation Rates and Methodology of Exhibit B-1 where FBC indicated that it:

> *"… proposes to provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR."*

Regarding changes to the depreciation expense amounts, depreciation expense varies from year to year based on the capital amounts that drive the expense. However, FBC would not make any changes to the method used to calculate depreciation expense during the term of the PBR without prior Commission approval.

90.0 Reference: Exhibit B-1, Section D3.6, Shared and Corporate Services.

90.1 Please confirm that there have been no changes to the allocations or methodologies for costs from Fortis Inc, Fortis Utilities Holdings Inc, or any other Fortis Entity to FBC from those previously approved by the BCUC. If not confirmed, please fully explain each change.

Response:

Except as described below, FBC confirms there have been no changes to the allocation methodologies for allocating costs from Fortis Inc., FortisBC Holdings Inc. or any other Fortis entity.

Starting in 2014 the Executive cross charges to and from FEI are expected to use the Massachusetts Formula during the term of the PBR, instead of management estimates of time allocations as used in the recent past. The Massachusetts Formula, as described in the Application, is a composition allocator and using this formula mimics the amount of time and effort that each of the executives spend, on average on each of the entities. Allocating the executive pooled costs (fully loaded labour with no overhead) 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.

90.2 Please confirm that there will be no change to the allocation methodologies during the term of the FBR. If not confirmed, please fully explain.

Response:

Please note that Section D3.6 refers to FBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP).

As stated in Section D3.6 "FBC does not propose any changes to the existing COC and TPP for this RRA. Should there be updates required to the COC or TPP during the PBR term, the Company will do so as part of FBC's RRA filings and Annual Reviews during the PBR period"

90.3 Please fully explain how the impact of acquisitions or divestitures by Fortis Inc, Fortis Utilities Holdings Inc, or any other Fortis entity will be dealt with during the term of the PBR.

Response:

Acquisition or divestitures by Fortis Inc. or FortisBC Holding Inc. have not been forecast to occur during the term of the PBR. These types of events are very difficult to forecast and so none of these types of events have been included during the term of the PBR. If these types of activities do occur during the term of the PBR, FBC does not propose to adjust the formula-driven O&M that is included in rates each year; these types of impacts are considered as part of the overall challenge FBC has in meeting its O&M targets under PBR.

90.4 On lines 24-25 of page 170, FBC indicates that costs are allocated from Fortis Inc. based on the "assets by subsidiary driver."

Response:

FBC confirms that the costs allocated from Fortis Inc are allocated based on subsidiary assets.

90.4.1 Please provide a working paper in support of the allocation of costs from Fortis Inc. to Fortis BC for the years 2010, 2011, 2012, and 2013.

Response:

The allocation of costs from Fortis Inc. to FortisBC Inc. for 2010, 2011, 2012 and 2013 is as follows:

Year	FortisBC Total Assets $	Fortis Inc.Total Assets $	Allocation %	Recoveries $000's	FP Mgmt Fee $000's	Net Pole Revenue $000's	Total costs being recovered $000's
2010 Actual	1,450,885	11,347,509	12.79%	1,659	(192)	(184)	1,283
2011 Actual	1,531,390	11,607,511	13.19%	1,855	(198)	(45)	1,612
2012 Actual	1,915,705	12,759,067	15.01%	2,176	(225)	(7)	1,944
2013 Pro Forma	2,076,236	13,264,278	15.65%	2,203	(235)	0	1,968

90.4.2 Please fully explain why the Massachusetts formula is not used for the allocation of Fortis Inc. Costs.

Response:

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 for the following reasons:

- Revenue is not a representative cost driver as revenue in the Fortis utilities is different and not 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.
- Payroll is also not an appropriate cost driver as the nature of the services from Fortis Inc. (i.e. services limited to equity and access to capital market, Governance, and to a lesser extent Financial Reporting and Risk Management/Insurance) to its subsidiaries is not related to the payroll costs in its utilities.

Instead of the Massachusetts method, Fortis Inc. believes that the Asset allocation method, in conjunction with Fortis Properties' management fee, is the more appropriate way to allocate its operating costs to its subsidiaries. The choice of the Asset allocation method is reflective of the autonomy with which Fortis Inc.'s regulated utilities operate, as the nature of the services being provided by Fortis Inc. (see above discussion) is more correlated with the net investment required of Fortis Inc. in its utilities.

90.4.3 Please provide a table that demonstrates how costs would be allocated from Fortis Inc. to Fortis BC for the years 2010, 2011, 2012, and 2013, using the Massachusetts formula, with the costs of natural gas or electricity excluded.

Response:

The table below compares the allocation of the Fortis Inc. (FI) fee to FortisBC Inc. (FBC) using net assets compared to using the Massachusetts formula. Please refer to the response to BCPSO 1.90.4.2 which explains why the Massachusetts formula is not used to allocate the costs from Fortis Inc.

The results of the two methods are presented in the table below and would result in a decrease in the charge to FBC if the Massachusetts formula was implemented. Even if the cost allocation methodology was changed, the same pool of costs from FI would be allocated to all of the FI regulated subsidiaries; however the distribution of those costs to the various FI regulated subsidiaries would be different.

(000's)	**Asset Allocation Model**			
	Actual			*Estimate*
	2010	**2011**	**2012**	**2013**
Net operating costs recoverable	**$ 10,015**	**$ 12,239**	**$ 12,953**	**$ 12,575**
FBC rate using Assets Allocation	12.79%	13.19%	15.01%	15.65%
Net operating costs allocated to FBC	$ 1,283	$ 1,612	$ 1,944	$ 1,968
	Massachusetts Formula Model			
	Actual			*Estimate*
	2010	**2011**	**2012**	**2013**
Net operating costs recoverable	**$ 10,015**	**$ 12,239**	**$ 12,953**	**$ 12,575**
FBC rate using Massachusetts formula	12.16%	12.80%	12.82%	12.43%
Net operating costs allocated to FBC	$ 1,218	$ 1,567	$ 1,661	$ 1,563
Difference - FBC	$ 65	$ 46	$ 284	$ 405

91.0 Reference: Exhibit B-1, Page 250, lines 16-22

Preamble: In lines 16-22, FBC indicates that, with the exception of the costs of executives, costs of resource sharing between FEI and FBC continues to use the approved cross charge methodology, including fully loaded wages.

91.1 Please provide an analysis of the costs allocated between FEI and FBC for 2008, 2009, 2010, 2011, and 2012 actual results, and the forecast 2013 and 2014. In the response, please provide the working papers in support of the derivation of the costs allocated.

Response:

The table below provides a summary of the actual cross charges between FEI and FBC for 2008 through to June 2013. For the remainder of 2013 and 2014, we are unable to provide the requested information as the historical information has been prepared based on the invoicing between the companies. The Company would not expect the remainder of 2013 and 2014 to be materially different.

	2008	2009	2010	2011	2012	2013 (YTD June)	2014
				($000s)			
FEI charges to FBC							
Total Transactions	310	352	429	1,177	1,661	984	
Office rental	(222)	(222)	(247)	(256)	(247)	(162)	
Purchase of Natural Gas	(15)	(12)	(11)	(13)	(9)	(7)	
Net cross charges	73	118	171	908	1,405	815	-
FBC charges to FEI							
Total Transactions	399	578	775	1,463	1,538	1,166	
Sale of Power	(380)	(561)	(721)	(778)	(452)	(179)	
Net cross charges	19	17	54	685	1,086	987	-

92.0 Reference: Exhibit B-1-1, Appendix F2, KPMG Study

Preamble: In Appendix F2, FBC provides a KPMG study related to Corporate Services.

92.1 Please confirm that this is the same report as filed in Appendix F2a of the FortisBC Energy Inc PBR Application. If not confirmed, please fully explain.

Response:

Confirmed.

92.2 If sub question 1 above is confirmed, please confirm that FBC is included in "Other Fortis Subsidiaries" as reported in Figure 3.1 – Organizational Chart. If not confirmed, please fully explain.

Response:

Confirmed.

92.3 In Table 5.5 of the KPMG study, the total FI recoverable operating costs are $12.575 million. On Table 5.7 of the KPMG report, $7.302 million of the $12.575 million is allocated to "Other". In Table 6.5, KPMG reports FHI costs of $12.423 million. Please provide a table similar to the KPMG Table 6.5 for costs allocated to FBC. In the response, please provide a reconciliation that clearly demonstrates the allocation of costs from Table 5.5 to "Other", then to FBC.

Response:

In the KPMG report, the "other" column in Table 5.7 includes FBC as indicated in the footnote. The table 5.7 of the KPMG report has been reproduced for FBC below. Table 6.5 cannot be reproduced as FBC does not have the same structure that FortisBC Energy has with a parent company that has certain functions in its local parent company. The Table 5.7 has been reproduced below showing the 2013 forecast costs allocated to FBC and showing all of the other subsidiaries under "Other".

2013 FI Management Fee Allocation

Service	FBC 15.65%	Other* 84.35%	Total
Executive	748,000	4,029,000	4,777,000
Treasury	75,000	402,000	477,000
Investor Relations	263,000	1,420,000	1,683,000
Financial Reporting	272,000	1,465,000	1,737,000
Internal Audit & Risk Management	118,000	633,000	751,000
Board of Directors	324,000	1,746,000	2,070,000
Other*	404,000	2,176,000	2,580,000
Subtotal	2,204,000	11,871,000	14,075,000
Less: Fortis Properties Management Fee Revenue	(235,000)	(1,265,000)	(1,500,000)
Total 2013 Forecast	**1,969,000**	**10,606,000**	**12,575,000**

* "Other" entities include Belize Electric Company Limited, FortisTCI (Turks & Caicos), FortisBC Holdings Inc, FortisAlberta, FortisOntario, Maritime Electric Company, Limited and Newfoundland Power

92.4 In Table 6.2 of the KPMG report, there is a management fee of $5.273 million. Please fully explain how management fees are included in the costs of FI, and how the recovery of management fees are included in forecast costs of FI.

Response:

To clarify, these costs are not included in FI's costs. In the table referenced above, the management fee (which includes the activities as described in Appendix F2 Table 5.2) is instead allocated from FI to FHI via a management fee charge. This management fee of $5.2 million is not applicable to FBC as FI directly charges FBC its share of the FI management fee.

93.0 Reference: Exhibit B-1-1, Appendix D5, Efficiency Carryover

Preamble: In Table D6-1 of Appendix D5, FBC provides "Rate Base Carrying Cost by Asset Type" in support of its "Rate Base Benefit Factor".

93.1 Please provided an updated table D6-1 that includes the net book value for each asset class.

Response:

Table D6-1 has been copied below, with the net book value at December 31, 2012 for each representative asset class included.

Note that the net book values provided reflect the capital investments made over time in these asset categories. Due to varying depreciation rates, the categories with lower depreciation rates by nature will not depreciate as quickly over time. Therefore, using the net book values in these categories to develop a weighted rate base carrying cost may give misleading results relative to a representative capital spending pattern for FBC.

Asset Type	Depreciation & CCA Rates	Five Year Levelized Rate Base Carrying Cost	Net Book Value December 31, 2012
Low Depreciation - Low CCA (Water Wheels, Turbines & Generators)	Depreciation - 1.95%, CCA - 8%	8.9%	90,947
Medium Depreciation - Low CCA (Station Equipment (Transmission Plant))	Depreciation - 3.44%, CCA - 8%	10.6%	165,358
Medium / High Depreciation - High CCA (Computer Equipment)	Depreciation - 7.61%, CCA - 55%	10.4%	20,649
High Depreciation - High CCA (Transportation Equipment)	Depreciation - 10.71%, CCA - 30%	15.2%	19,335

94.0 Reference: Exhibit B-1, Section D3.7, Capitalized Overhead.

94.1 Please confirm that FBC will maintain a Capitalized Overhead rate of 20% throughout the PBR term. If not confirmed, please fully explain

Response:

The Company has proposed that the Capitalized Overhead rate of 20 percent be maintained throughout the PBR term.

95.0 Reference: Exhibit B-1, Section D9, Presentation Material

Preamble: On Slide 6, FBC indicates that one of its PBR objectives is:

> To create an efficient regulatory process for the upcoming years, allowing the companies to focus on effectively managing business priorities and minimizing costs for customers.

FBC also proposes an annual review and a mid term review. On slide 63, FBC presents a summary of the annual review. The BCPSO requires additional information to assess the potential for a reduction in regulatory burden.

95.1 Please provide a complete discussion of the information to be presented;, decisions to be rendered by the Commission; and the process to be undertaken during the annual review.

Response:

This question is similar to FEI's 2014-2018 PBR Application, BCPSO IR 1.12.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

The Annual Review is discussed in detail in Section B6.8 (pages 71 and 72) of the Application. There are two main purposes of the Annual Review. First, the Annual Reviews will review the results of PBR for the current year, including, among other things, projected financial results and earnings sharing, and FBC's performance with respect to the service quality indicators. Secondly, the Annual Reviews will set rates for the coming year. Rates will be set according to the I-X provisions affecting O&M and capital expenditures and forecast flow-through items, as well as any exogenous factors that are brought forward to be considered in the Annual Review and approved by the Commission.

The Annual Review can therefore be characterized as a key element of the normal yearly cycle of setting rates and communicating with customers about how the PBR is unfolding.

95.2 Please fully explain how this annual process will result in a lower regulatory burden than periodic, multi-year Cost of Service Applications.

Response:

FBC believes that the costs of Annual Reviews will be considerably less than the costs associated with multi-year revenue requirements. Annual reviews are typically following the Application and IRs, a one day process before the Commission and Stakeholders with specific filing requirements as laid out in the Application. Full Cost of Service or Revenue Requirement Applications involve substantial material preparation and filing with the Commission, followed a longer regulatory process, and written or oral hearing followed by final and reply argument. The Company estimated costs of approximately $1 million for its last RRA proceeding, and FBC believes costs for the Annual Review processes will be a fraction of that. In addition to the direct costs of the hearing there is the indirect cost burden from diverting management from managing the business to managing the regulatory process. These direct and indirect costs will be materially reduced.

96.0 Reference: Exhibit B-1, Tab D, pages 236-237 and pages 263-264

Exhibit B-1, Tab B, page 61 (lines 27-32)

Preamble: The Application states (page 237) that:

> *"This proposed Interest Expense Variance rate base deferral account would capture the impact on interest expense of short-term and long-term interest rate variances, as well as variances associated with the volume and timing of issuing long-term debt, as compared to what has been forecast for rate-setting purposes. The ability and timing to issue long-term debt is also dependent on the debt markets and are not within FBC's control."*

The Application also states (page 61):

> *"A deferral account will record variances in long-term and short-term interest costs in accordance with the method approved by the Commission for FEI. Projected deferral account balances and forecasts of short term and long term interest rates and costs will be provided each year during the Annual Review process."*

96.1 Please clarify which sources of variance the calculation of the interest expense variance will capture – e.g. i) differences between forecast and actual interest rates for the PBR year, ii) differences between the amount of debt required to issued based on forecast capital spending (per the PBR formulae/allowed adjustments) and that issued based on actual capital spending iii) differences between the actual rate base and that established under the PBR plan and/or iv) differences in timing as between when during the PBR year debt was forecast to be issued and when it actually was issued.

Response:

The sources of the variance calculation on the Interest Expense Deferral Account are as follows:

(i) The interest expense variability based on the differences between forecast and actual long-term and short-term interest rates for each year under the PBR (interest will be re-forecast annually as part of the Annual Review) will be captured in the Interest Expense Deferral Account.

(ii) The interest expense variability based on the difference between the weighted average long-term debt balances, thereby capturing the timing and amount of proceeds on the long-term debt issuance, for each year under the PBR will be captured in the Interest Expense Deferral Account

(iii) The interest expense variability based on the difference between the forecast and actual standby fee rates included in short-term interest expense financing fees

Please refer to the response to BCUC IR 1.190.5.1 for an illustrative example of which variances are to be added to the Interest Expense Deferral Account.

96.2 To assist further with this understanding please provide an illustrative example indicating how the calculation would be done.

Response:

Please refer to the response to BCUC IR 1.190.5.1 for the illustrative example.

97.0 Reference: Exhibit B-1, Tab D, pages 261-262

Exhibit B-1, Tab C, page 75

97.1 Is FortisBC seeking approval for the 2014-2017 amortization of the proposed RSDM account as set out in Table D4-2? Alternatively, is amortization for 2015-2017 potentially subject to change in future applications during the PBR period?

Response:

Yes, FBC is seeking approval to amortize the RDSM over the period 2015 – 2018. The amortization amount is not subject to change in future periods during the PBR Period. Please refer to the responses to BCUC IR 1.185.3 through BCUC IR 1.183.3.2 for a discussion of the RDSM and amortization of the account.

97.2 Please confirm that, as a rate base deferral account, the remaining credit in the account will serve to reduce the annual financing costs included in rates over the PBR plan period.

Response:

Confirmed. The RDSM account reduces rate base and the associated Interest Expense, Cost of Equity and Income Tax Expense over the PBR Period.

97.3 Please confirm whether the rate smoothing associated with the WAX CAPA was meant to "smooth out" near term rate increases or decreases.

Response:

Confirmed. In its Order E-15-12 the Commission stated that "although the WAX CAPA is a long-term capacity purchase agreement and is in the public interest, there is the potential for disproportionate rate impacts in the early years of the agreement."

Order E-15-12 then directed FBC "to develop a rate smoothing proposal for the Commission's approval either through a separate submission or with the next Revenue Requirements Application."

97.4 Did either of the rate stabilization mechanisms describe on pages 261-262 involve implementing higher rate increases in the earlier years so as to allow for lower rate increases in the later years than would have otherwise occurred?

Response:

Yes. Effectively both the FBC and FEVI rate stabilization mechanisms described on pages 261-262 involved customer paying initially higher rates, than they otherwise would have, which offset rates going forward. Although both mechanisms operated differently, they both had the same effect of pre-collecting from customers and mitigating rate increases in the future.

FBC had determined that certain asset classes had been over depreciated. Rather than refunding the over-collected depreciation at that time, it was determined that the refunds would be made going forward and used to cap future rate increases at no more than 5%. Eventually, this mechanism was abandoned in favor of updated depreciation rates pursuant to a new depreciation study.

FEVI's RSDA was implemented January 1, 2010 as an interim rate mitigation strategy to offset the rate pressure expected to result from the loss of gas royalty revenues on December 31, 2011. The accumulated surplus in the account in 2010 and 2011 was the result of freezing FEVI customer rates compared to the 2009 rates, which means that those rates were higher than they otherwise would have been. Beginning in 2013, the approved FEVI revenue requirements included a deficiency that would have resulted in a rate increase to Vancouver Island customers had the accumulated RSDA balance not been used to offset the increase.

97.5 Please provide any evidence FortisBC has regarding customer preferences for a rate stabilization mechanism that would lead to higher rates in the near term or studies about customer cost of capital that would indicate customers are preference regarding the inclusion or exclusion of a rate stabilization fund.

Response:

FBC has no direct evidence to this effect. The proposal for a RSDM complies with the Commission's direction in Order E-15-12 to bring forward a rate smoothing mechanism to address the short term impacts of the WAX CAPA.

98.0 Reference: Exhibit B-1, Tab D, page 262, lines

98.1 Please confirm that the BCUC has ordered that the impacts of the Stage 1 GCOC Decision (as they pertain to FortisBC) will be effective January 1, 2013, regardless of the effective date of the Stage 2 Order.

Response:

Confirmed. FBC's 2013 ROE decreased from the interim 9.90 percent to 9.15 percent effective January 1, 2013. The Company has recorded the 2013 revenue requirements impact of the Stage 1 decision in a deferral account and proposes to amortize the amount in 2014.

99.0 Reference: Exhibit B-1, Tab E, page 277

Exhibit B-1-1, Appendix G, page 1

99.1 Please confirm that the Revenue Requirements Overview for 2014 (page 277) and for 2014-2018 (Appendix G) on above referenced pages are based on the adoption of the proposed PBR plan as described in Tab B as opposed to the forecasts set out in Tab C.

<u>Response:</u>

Confirmed.

99.1.1 If yes, please confirm whether the Appendix G Schedule includes the impact from spending on any of the future CPCN Applications described on pages 226-231.

<u>Response:</u>

No. FBC has not included the rate impacts of future CPCN projects. To ensure transparency and accuracy of revenue requirements related to CPCN project timing, CPCN projects will not be included in revenue requirements until approved. This is consistent with the approved regulatory treatment of other utilities' capital expenditures, including those of FEU.

99.1.2 If yes, please provide a similar formatted schedule based on the 2014-2018 forecasts set out in Tab C and that reconciles with the "Indicative Cost of Service" projection set out in Figure B7-1.

<u>Response:</u>

The following table is indicative of "Cost of Service" projection with no Rate Stabilization as set out in Figure B7-1:

Revenue Requirements Overview

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Sales Volume (GWh)	3,240	3,258	3,276	3,295	3,318
2	Rate Base	1,238,275	1,280,773	1,301,777	1,310,647	1,314,895
3	Return on Rate Base	7.12%	6.96%	6.99%	7.01%	7.01%
4						
5	**REVENUE DEFICIENCY**					
6						
7	**POWER SUPPLY**					
8	Power Purchases	87,814	116,380	134,204	136,716	140,322
9	Water Fees	10,057	10,532	10,479	10,688	10,902
10		97,871	126,913	144,683	147,404	151,224
11	**OPERATING**					
12	O&M Expense	61,384	61,593	60,618	61,899	62,644
13	Capitalized Overhead	(12,277)	(12,319)	(12,124)	(12,380)	(12,529)
14	Wheeling	5,224	4,856	4,952	5,050	5,208
15	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
16		46,750	46,501	45,666	46,815	47,504
17	**TAXES**					
18	Property Taxes	15,903	16,329	16,612	16,975	17,290
19	Income Taxes	1,827	5,785	7,427	9,263	10,530
20		17,730	22,114	24,038	26,238	27,820
21	**FINANCING**					
22	Cost of Debt	42,787	42,239	43,409	43,869	44,086
23	Cost of Equity	45,321	46,876	47,645	47,970	48,125
24	Depreciation and Amortization	57,773	56,129	58,319	60,722	63,039
25		145,882	145,244	149,374	152,561	155,251
26						
27	Flow Through Adjustments	(14,207)	-	-	-	-
28	Rate Stabilization	-	-	-	-	-
29		(14,207)	-	-	-	-
30						
31	**TOTAL REVENUE REQUIREMENT**	294,026	340,772	363,761	373,018	381,799
32						
33	**LESS: REVENUE AT APPROVED RATES**	312,923	295,576	342,605	365,940	375,665
34	**REVENUE DEFICIENCY FOR RATE SETTING**	(18,898)	45,196	21,155	7,077	6,133
35						
36	**RATE INCREASE**	**-6.00%**	**15.30%**	**6.20%**	**1.90%**	**1.60%**
37	**CUMULATIVE RATE INCREASE**	**-6.00%**	**8.38%**	**15.10%**	**17.29%**	**19.17%**

99.1.3 If no. what does the schedule reflect and please provide a similar formatted version for 2014-2018 based on the proposed PBR plan and indicate the impact, if any, of the projects described on pages 226-231.

Response:

No response is required as the Revenue Requirements Overview for 2014-2018 are based on the adoption of the proposed PBR plan.

100.0 Reference: Exhibit B-1, Tab E, pages 280-284

100.1 If the 2014 capital expenditures are based on the capital formula (pages 56-57 and 58), how were the total forecast expenditures assigned to individual capital projects?

Response:

The 2014 Capital Expenditures were initially assessed on a detailed project by project basis (Refer: Exhibit B-1, Tab B, Figure B6-3 – Capital Forecast). The total expenditures were then compared to the formulaic PBR Capital value (Refer: Exhibit B-1, Tab B, Table B6-7 – Total Capital under PBR). The variance between these two numbers ($2.419 million in 2014) is considered to be the savings that FBC intends to achieve during the year and is accounted for by the "PBR Adjustments" component of Capital (Refer: Exhibit B-1, Tab E, Page 283, Table 1-A-1, Line 24).

101.0 Reference: Exhibit B-1, Appendix G, Schedule 1

101.1 Please provide a schedule that reconciles the plant in-service in each year with the forecast capital expenditures as set out on page 58 (Table B6-7). Please also provide the basis for any assumptions made in translating annual capital spending into annual plant in-service.

<u>Response:</u>

The relevant reconciling schedule has been provided below:

The Plant in Service amount was determined on a project by project basis after evaluation of the expected plant that will become useful during a particular year (while the balance of the expenditure remains as CWIP (Construction Work in Progress)). No general assumption was applied.

Capital Parameters	2014	2015	2016	2017	2018	Remarks
	($000s)					
Unloaded Capital Expenditure under PBR	**72,757**	**68,949**	**52,103**	**53,183**	**54,060**	Refer Exhibit B-1, Tab-B, Page 58, Table B6-7
Add Loadings	18,652	17,776	17,554	17,684	18,050	
Less Cost of Removals	(4,465)	(2,676)	(2,768)	(2,837)	(3,229)	
Loaded Capital Expenditure Under PBR	86,944	84,049	66,889	68,029	68,881	
Add Opening CWIP	21,308	10,295	9,494	8,536	8,152	
Less Closing CWIP	(10,295)	(9,494)	(8,536)	(8,152)	(11,493)	
Plant in Service Additions	97,957	84,850	67,847	68,413	65,541	
Less Retirements	(15,206)	(15,206)	(7,444)	(7,444)	(7,444)	
Add Kettle Valley Adjustments	3,416	-	-	-	-	
Net Plant Additions	86,167	69,644	60,403	60,969	58,097	Refer Exhibit B-1-1, Appendix-G, Schedule-1, Page-2, Line-2
Brought Forward Plants in Service as of Jan 1	1,718,111	1,804,278	1,873,922	1,934,325	1,995,295	
Plant in Service as of December 31	**1,804,278**	**1,873,922**	**1,934,325**	**1,995,295**	**2,053,392**	Refer Exhibit B-1-1, Appendix-G, Schedule-1, Page-2, Line-3

Note: Minor differences due to rounding

101.2 What is the basis for the "Deferred and Preliminary Charges" 2014-2018 forecast as set out in Schedule 1.

<u>Response:</u>

The detailed forecast for 2014 Deferred Charges is found in Section E, Table 1-B at pages 285-286 of the Application. In order to forecast Deferred Charges for 2015-2018, FBC applied the approved and/or amortization periods for the balances as at December 31, 204. In addition, the Company identified and estimated on a preliminary basis the items, consistent with the treatment of deferral accounts described in Section D4 of the Application that it expects to require during the 2015-2018 period. New deferral accounts for 2015 and future years will be identified at each Annual Review for setting rates in the next year.

102.0 Reference: Exhibit B-1, Appendix H, pages 4, 13 and 14

102.1 Please explain why FortisBC is using a value of $56.61/MWh (primarily reflective of BC Market costs) for the TRC test screening of DSM measures when the DSM regulation defines FortisBC Inc's long-run marginal cost as the cost of acquiring electricity generated from clean or renewable resources.

Response:

Please refer to the response to BCUC IR 1.242.3.1.

102.2 What is FortisBC Inc. current estimate of the long-run marginal cost of acquiring electricity generated from clean or renewable resources?

Response:

FortisBC's current proxy for LRMC of acquiring electricity generated from clean or renewable resources is $111.96/MWh.

102.3 What are the current long-run marginal cost values used FortisBC's RCR and proposed for use in it Stepped Rates for Transmission customers.

Response:

No value of LRMC is used in the RCR. The Block 1 and Block 2 Rates are determined per the Commissions Direction contained in Order G-3-12. Please refer to the response to BCUC IR 1.242.1.1.

In the Company's proposal for Stepped Rates for Transmission customers, a LRMC value of $92.23 / MWh is used for the Tier 2 rate. Please refer to the response to BCUC IR 1.242.2.

102.4 Please explain why it is appropriate to use materially different values for purposes of i) sending pricing signals that will impact customers' consumption decisions versus ii) determining which DSM programs to offer that will impact customers' consumption decisions.

Response:

Please refer to the response to BCUC IR 1.242.1.1.

103.0 Reference: Exhibit B-1, Appendix H, page 4

103.1 Why does FortisBC not have and is not proposing any fuel switching programs?

Response:

The Clean Energy Act (CEA) explicitly excludes "a rate, measure, action the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia". Since electricity such as that distributed by FortisBC is largely produced from GHG-free sources, fuel switching programs that encourage customers to use lower-cost natural gas do not qualify as a Demand Side Measure in British Columbia, despite the relief that it could give some customers on their bills for space and water heating.

FBC has considered a fuel switching initiative under s.18 of the CEA, that would encourage customers with high-carbon, high-cost fuels (such as propane and heating oil) to switch to electricity, but the potential is small and analysis is incomplete so no such proposal has been submitted.

104.0 Reference: Exhibit B-1, Appendix H, page 10

104.1 Please provide a revised version of Table H-5 that lists all of the DSM Programs approved for 2012-2013 and notes which ones are "continuing" in the 2014 DSM Plan.

Response:

A revised Table H-5 is shown below, modified as requested.

Program Area	DSM Programs	Approved in 2013 -2013	Proposed for 2014-2018
Residential	Home Improvement (Building Envelope) Program	X	X
	Heat Pump Program (Air-Source, GeoExchange)	X	X[6]
	ENERGY STAR® Heat Pump Water Heater Program	X	X
	Water Savers (Low-Flow Fixtures)	X	X
	ENERGY STAR® Residential Lighting	X	X
	New Home Program	X	X
	Home Retrofit Financing Pilot	X	X
	ENERGY STAR ® Appliance Program	X	
	ENERGY STAR ®Electronics Program	X	
	Behavioural Program (e.g. clotheslines)	X	
Commercial	Commercial Lighting Program	X	X
	Building & Process Improvement Program[7]	X	X
	Product Rebate Program	X	X
	Irrigation Program	X	X
	Computer - Data Centre and Server Program	X	
	Municipal Water Handling Infrastructure Program	X	
Industrial	Industrial Efficiency Program	X	X

[6] Except GeoExchange heat pumps (discontinued)

[7] Includes Commercial Energy Assessment program

Program Area	DSM Programs	Approved in 2013 -2013	Proposed for 2014-2018
Low Income /Rental	Energy Savings Kit	X	X
	Energy Conservation Assistance Program[8]	X	X
	Direct Install Lighting[9]	X	
Conservation Education & Outreach	Public Awareness Program	X	X
	School Education Program	X	X

[8] Expected start date – fall 2013
[9] Known building stock will have been completed in 2013

105.0 Reference: Exhibit B-1, Appendix H1, pages 6-7

105.1 Please outline specifically what basic and extended conservation measures will be included for screening in the direct installation program.

Response:

FBC intends to partner with BCH and FEU to offer a provincial direct installation program for low-income households in 2014. At the time of writing, a thorough review of the ECAP (Energy Conservation Assistance Program) program with the intention to redesign it is being completed by a third-party consultant.

Although final determination for program design will not be made until later in the fall of 2013, it is expected that the basic conservation measures for ECAP will include the installation of Energy Savings Kit measures (low-flow showerheads, compact fluorescent lights and weather stripping, for example.). Building envelope improvement measures, including insulation, draft-proofing and ventilation measures, would be provided for the homeowners that have met eligibility requirements and whose homes require the measures.

105.2 Precisely how will the "screening tools" be testing for appropriateness and cost-effectiveness?

Response:

At the time of writing, a thorough review of the ECAP program is being completed by a third-party consultant. The consultant will recommend screening tools for approval by the three partner utilities. The specific screening tools have not yet been determined, but it is expected that all program components will be determined by late 2013.

105.3 What is the degree/level of incentives that will be offered under the Rental Accommodations Programs?

Response:

In 2014, FBC will provide up to 1,000 energy savings kits for rental units (multi-and single-family)

Building owners that rent their single-family homes will be encouraged to participate in the LiveSmart BC programs to receive subsidized NRCan certified home energy assessments and to participate in the LiveSmart BC and/or FBC Home Improvement rebate programs. Building owners may also qualify for the FBC on-bill finance program (Residential Energy Loan Program).

106.0 Reference: Exhibit B-1, Appendix H2, pages 6 and 12

106.1 How were the actual savings reported on page 6 determined? Have they been vetted for free riders and/or subject to any 3rd party verification/evaluation?

Response:

The actual savings reported on page 6 were determined by adjusting the gross savings with the net-to-gross (NTG) ratios determined by program evaluations. The NTGs include savings realization rates (verification of savings), free rider rates and where appropriate, spill over rates.

106.2 In Table 13 what avoided cost measure was used to determine the values reported in the Program Benefits column?

Response:

The values reported in the Program Benefit column of Table 13 were determined using the 2012-13 approved avoided cost of $84.94/MWh, plus a Deferred Capital Expenditure factor of $35.60/kW-yr.

107.0 Reference: Exhibit B-1, Appendix H4

107.1 Please confirm that the calculations set out in Appendix H4 do not include any allowance for capacity costs.

Response:

Not confirmed. The underlying BC Wholesale Market Curve is principally based on a forecast of Mid-C market prices. The delivery of firm market energy in any hour must be backed by firm capacity, so capacity costs are implicitly included in the price.

107.1.1 If confirmed, why is it not appropriate to also include a value for avoided capacity costs in the long-run marginal costs used to evaluate DSM programs?

Response:

Please refer to the response to BCPSO IR 1.107.1.

107.1.2 If not confirmed, please indicate how capacity costs are reflected in the calculation?

Response:

Please refer to the response to BCPSO IR 1.107.1.

107.2 Why was the BC Market Cost Curve used to determine FortisBC's avoided cost over the entire 2014-2043 period when the strategy set out in FortisBC's 2012 Long Term Resource Plan (Table 1.4) calls for adoption of a "Build Strategy" after 2020?

Response:

FBC's 2012 Long-Term Resource plan does not specify a specific date for the changeover from a buy to build strategy, only that it will be in the long-term and that need would be evaluated in future resource plans. Given FBC's current long term power supply resources, the market assessment and the resource options report provided in the Resource Plan, market purchases were expected to represent FBC's least cost resource to meet the Company's incremental energy demand in the short to medium term. FBC's January 2013 BC Market energy price provided an updated assessment of the PNW power markets resulting in a downward shift in market pricing, and therefore supports the expectation that market supply may continue to be cost effective over the longer term.

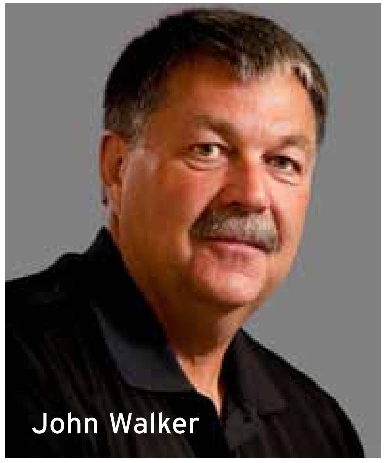
Attachment 9.2

FortisBC 2012 Electric corporate scorecard

Q4 performance results

FortisBC (Electric) achieved 125.6 per cent for 2012, with the fourth quarter capping a year of solid performance in almost all target areas.

We maintained our focus on customer service throughout the year with satisfaction results consistent with the target. Additionally, SAIDI results were better than the previous three year average.



The Customer Service Index average for the four quarters was 8.4 and measured customers' overall satisfaction with the company, field services, accuracy of meter reading, energy conservation information and contact centre services. Customers indicated that price and reliability were primary areas of concern, however we can continue to improve by focusing on positive drivers such as high first call resolution, friendly and knowledgeable staff and the company's environmental responsibility.

2012 marked a year of improvement for driver safety performance with a lower number of vehicle accidents compared to the previous year. The ongoing focus on the **Drive to Zero** was communicated often and to all employees throughout the year. Still, we must remain vigilant and remember that avoiding preventable accidents is of the utmost importance to FortisBC and should be a priority for all employees. The All Injury Frequency Rate (AIFR) did not meet its target and serves as a reminder of the need to maintain our safety focus in all aspects of our work.

On the regulatory front, 2012 was an intense and successful year. A number of applications proceeded through the regulatory process, such as the Advanced Metering Infrastructure project and the 2012/2013 Revenue Requirement application, the largest and most complex filing that the company has undertaken in recent history. The electric division filed nine major applications, responding to over 5,000 information requests, continuing the upward trend from 3,000 in 2011 and 2,300 in 2010. In total, 174 different BCUC filings were completed.

As we move forward on all major aspects of our business and focus our productivity, this scorecard will continue to serve as a gauge by which to measure our success.

Customer satisfaction

Customer service results were 8.4. Customers have indicated satisfaction through FortisBC's high first call resolutions, knowledgeable staff and environmental responsibility.

Safety

Vehicle accidents remained on track in the fourth quarter, with the annual results achieving a top-out rating while the AIFR did not meet the annual target.

Regulatory

Work continued on moving forward the Advanced Metering Infrastructure project with the company responding to information requests during the quarter. An application was also filed with the BCUC seeking approval for the purchase of the City of Kelowna distribution assets. Approval by the BCUC would result in approximately 15,000 customers located in central Kelowna becoming FortisBC customers.

Financial

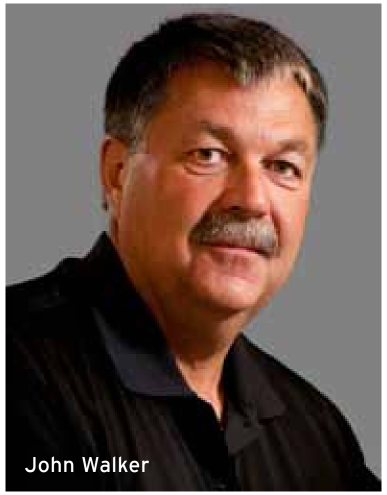
We finished the year with strong financial results. Regulated earnings totalled $48.5 million, more than our target of $44.1 million and greater than the $47.5 million earned in 2011.

Q4 fourth quarter performance results

Category	Measurement	Target	Results	Status
Customer	Customer Service Index (CSI)	8.5	8.4 (9.38%)	Below target
	System average interruption duration index (SAIDI)	2.33	1.95 (18.75%)	Ahead of target
Safety	All Injury Frequency Rate (AIFR)	1.54	1.72 (0.0%)	Below target
	Recordable vehicle incidents	31	22 (15.0%)	Ahead of target
Regulatory	Regulatory Performance	Subjective	(37.5%)	Ahead of target
Financial	Regulated Earnings $ millions	$44.1	$48.5 (45.0%)	Ahead of target

Q4 performance results: 125.6%

FortisBC 2012 Electric Corporate Scorecard


John Walker

My following message to you includes detailed information about our new 2012 scorecard. This year we've worked to standardize the scorecard categories between the gas and electric businesses as we further align and integrate the organization. However, there are measures specific to each business in its respective scorecard. Eligible FortisBC employees receive annual incentive pay, based on the achievement of corporate scorecard targets during the period from January 1 to December 31, 2012.

The key changes to the electric scorecard compared to 2011 include: the Financial category (regulated earnings) replaces the Productivity (controllable O&M) category, Recordable Vehicle Incidents has been added as a safety measure, and there are changes to the number of measurement categories and target levels.

In each target category three performance levels are used: Threshold (changed to 50% from 0%), Target (100 %) and Maximum (changed to 150% from 100%). The targets are weighted to balance the interests of our various stakeholders. The incentive payment is made in February when the previous year's results have been finalized and approved by the Board. Incentive is paid when 85 per cent of the earnings target is achieved. The year-end result reflects the sum of the achieved performance levels in each measurement category. The scorecard performance is reported quarterly.

Description of Targets

Customer Satisfaction

This is made up of two measures: the Customer Service Index and the System Average Interruption Duration Index (SAIDI) reliability measure. The independent customer survey is conducted four times per year. It measures customers' overall satisfaction with the Company, field services, accuracy of meter reading, energy conservation information and contact centre services. The SAIDI reliability target represents the reliability of the power system in terms of outage duration (hours per customer) for all outages greater than one minute.

Safety

Employee safety is measured through the All Injury Frequency Rate which reflects both medical aids and lost time injuries based on a three-year average. Recordable Vehicle Incidents are also based on a three-year average and include any incident with the exception of properly parked vehicles. Although targets are set, our ultimate goal is zero.

Regulatory

It is anticipated that the company will face significant regulatory activity in 2012. Some anticipated filings include one for Advanced Metering Infrastructure as well as power purchase and rate design filings. There will also be several Certificates of Public Convenience and Necessity (CPCNs) filed in support of projects identified in the 2012 capital plan. Our overall objective is to submit efficient, accurate and complete filings that result in quick conclusions and give the regulator and customer confidence in our ability to generate, transmit and deliver energy, safely and reliably at the lowest reasonable cost.

Financial

FortisBC electric uses regulated earnings as a financial performance measure. This target measures regulated earnings based upon year-end financial results and takes into account electricity revenue and other income, less power purchases, water fees, operating and maintenance expense (net of capitalized overhead), wheeling, property taxes, income taxes, cost of debt, any flow-through adjustments, depreciation and amortization. The target reflects FortisBC's proposed regulated earnings from the 2012 Business Plan and the 2012-2013 Revenue Requirements Application submitted to the British Columbia Utilities Commission (BCUC), which assumed a return on equity of 9.9 per cent. The 2012-2013 Revenue Requirements is currently in a regulatory process with the BCUC. The BCUC has ordered a generic cost of capital hearing in 2012. The regulated earnings target will be adjusted to reflect the outcome of the Revenue Requirements and the cost of capital process.

2012 Corporate incentive targets—Electric

Category	Measurement	Target 100%
Customer	Customer Service Index (CSI)	8.5
	System Average Interruption Duration Index (SAIDI)	BCUC target 2.33
Safety	All Injury Frequency Rate (AIFR)	Average of the last three years 1.54
	Recordable Vehicle Incidents	31
Regulatory	Regulatory performance	Subjective
Financial	Regulated earnings	Plan $45.3 M

Predetermined corporate targets help focus employees on achieving results that add value to customers, employees and other stakeholders.

Attachment 30.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 30.6

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

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VIA EMAIL

April 18, 2013

Ms. Diane Roy
Director, Regulatory Affairs – Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
(gas.regulatory.affairs@fortisbc.com)

Mr. Dennis Swanson
Director, Regulatory Affairs
FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC V1Y 7V7
(electricity.regulatory.affairs@fortisbc.com)

Dear Ms. Roy and Mr. Swanson:

Re: FortisBC Energy Inc.
and FortisBC Inc.
2014 Revenue Requirements Application
Productivity Improvements in a Performance Based Rate Setting Environment

The British Columbia Utilities Commission (Commission) writes to provide FortisBC Energy Utilities and FortisBC Inc. (together the Companies), with further direction regarding the inclusion of an evaluation of Performance Based Regulation (PBR) methodologies, utilized in Canada and a proposal for a PBR methodology in the Companies' next Revenue Requirements Applications (RRA).

Commission Decisions on the FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application (FEU 2012-2013 RRA) and the FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan (FortisBC 2012-2013 RRA and ISP) examined productivity improvements under a PBR setting.

The FEU 2012-2013 RRA Decision found there was sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements but also recognized that there are limitations to the PBR methodology. The FortisBC 2012-2013 RRA and ISP Decision had the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in a productivity improvement culture.

The Commission requires FEU and FortisBC to describe its productivity improvement culture by an examination of PBR methodologies in its next Revenue Requirements Applications. This examination is to evaluate the most recent PBR methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada. FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture.

Yours truly,

EHamilton

Erica Hamilton

PWN/yl

IP/April/FEI/04-18-2013_FEI-FBC_PBR 2014RRA

Attachment 52.2

INTEREST RATE OUTLOOK

	2012				2013				2014			
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA												
Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50
3-mth T-Bill Rate	0.91	0.87	0.97	0.92	0.95	0.95	0.95	0.95	0.95	0.95	1.05	1.40
2-yr Govt. Bond Yield	1.20	1.03	1.07	1.14	1.00	1.10	1.15	1.20	1.25	1.35	1.50	1.70
5-yr Govt. Bond Yield	1.57	1.25	1.30	1.38	1.35	1.45	1.55	1.60	1.70	1.80	1.95	2.05
10-yr Govt. Bond Yield	2.11	1.74	1.73	1.80	1.85	1.95	2.10	2.20	2.40	2.50	2.60	2.70
30-yr Govt. Bond Yield	2.66	2.33	2.32	2.36	2.50	2.55	2.70	2.75	2.95	3.10	3.15	3.25
10-yr-2-yr Govt Spread	0.91	0.71	0.66	0.66	0.85	0.85	0.95	1.00	1.15	1.15	1.10	1.00
U.S.												
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-mth T-Bill Rate	0.07	0.09	0.10	0.05	0.10	0.15	0.20	0.20	0.20	0.30	0.40	0.40
2-yr Govt. Bond Yield	0.33	0.33	0.23	0.25	0.25	0.28	0.30	0.35	0.40	0.50	0.60	0.80
5-yr Govt. Bond Yield	1.04	0.72	0.62	0.72	0.75	0.90	1.00	1.10	1.25	1.40	1.55	1.75
10-yr Govt. Bond Yield	2.23	1.67	1.65	1.78	1.90	2.05	2.20	2.30	2.50	2.70	2.80	3.00
30-yr Govt. Bond Yield	3.35	2.76	2.82	2.95	3.05	3.15	3.40	3.50	3.75	3.95	4.05	4.10
10-yr-2-yr Govt Spread	1.90	1.34	1.42	1.53	1.65	1.77	1.90	1.95	2.10	2.20	2.20	2.20
CANADA - U.S SPREADS												
Can - U.S. T-Bill Spread	0.84	0.78	0.87	0.87	0.85	0.80	0.75	0.75	0.75	0.65	0.65	1.00
Can - U.S. 10-Year Bond Spread	-0.12	0.07	0.08	0.02	-0.05	-0.10	-0.10	-0.10	-0.10	-0.20	-0.20	-0.30

F: Forecast by TD Bank Group as at March 2013; All forecasts are end-of-period; Source: Bloomberg, Bank of Canada, Federal Reserve.

FOREIGN EXCHANGE OUTLOOK

Currency	Exchange rate	2012				2013				2014			
		Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Exchange rate to U.S. dollar													
Japanese yen	JPY per USD	82	80	78	87	88	88	90	92	93	97	100	100
Euro	USD per EUR	1.33	1.27	1.29	1.32	1.30	1.35	1.38	1.35	1.35	1.35	1.32	1.32
U.K. pound	USD per GBP	1.60	1.57	1.61	1.63	1.51	1.59	1.62	1.61	1.61	1.61	1.61	1.61
Exchange rate to Canadian dollar													
U.S. dollar	USD per CAD	1.00	0.98	1.02	1.00	0.97	0.94	0.98	0.98	1.01	1.02	1.03	1.03
Japanese yen	JPY per CAD	79.2	79.3	79.0	82.0	85.4	82.7	88.2	90.2	93.9	98.9	103.0	103.0
Euro	CAD per EUR	1.31	1.30	1.25	1.29	1.34	1.44	1.41	1.38	1.34	1.32	1.28	1.28
U.K. pound	CAD per GBP	1.57	1.60	1.57	1.59	1.56	1.69	1.66	1.64	1.59	1.58	1.56	1.56

f: Forecast by TD Bank Group as at March 2013; All forecasts are end-of-period: Source: Federal Reserve, Bloomberg, TDBG

COMMODITY PRICE FORECASTS

	2012				2013F				2014F				Annual Average		
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	2012	2013F	2014F
Crude Oil (WTI, $US/bbl)	103	93	92	88	94	90	92	95	97	95	95	93	94	93	95
Natural Gas ($US/MMBtu)	2.45	2.28	2.88	3.40	3.35	3.65	3.25	3.75	3.90	4.00	3.90	4.25	2.75	3.50	4.01
Gold ($US/troy oz.)	1690	1612	1655	1717	1630	1625	1650	1550	1525	1490	1475	1425	1668	1614	1479
Silver (US$/troy oz.)	32.6	29.5	30.0	32.6	30.2	31.8	32.0	27.5	27.0	26.0	25.5	24.3	31.17	30.35	25.69
Copper (cents/lb)	376	357	350	359	360	355	375	350	345	335	330	325	361	360	334
Nickel (US$/lb)	8.91	7.77	7.42	7.70	7.85	8.50	8.25	8.00	8.01	8.68	8.42	8.17	7.95	8.15	8.32
Aluminum (Cents/lb)	99	90	87	91	92	95	100	98	93	96	101	99	92	96	97
Wheat ($US/bu)	9.54	9.36	9.90	10.05	9.35	9.50	9.65	9.50	9.35	9.25	9.00	8.75	9.71	9.50	9.09

F: Forecast by TD Bank Group as at March 2013; All forecasts are period averages; Source: Bloomberg, USDA (Haver).

Canada
Economic Forecast

(Annual % change)*	2010	2011	2012	2013	2014	Q4/Q4 2013	Q4/Q4 2014
Gross domestic product (2007 $)	3.2	2.6	1.8	1.5	2.2	2.0	2.3
Consumption	3.5	2.4	1.9	2.0	1.9	1.8	2.0
Residential construction	7.9	1.9	5.8	(3.1)	0.1	(3.3)	0.7
Business investment	14.5	10.4	6.2	3.5	5.3	4.3	5.2
Government expenditures	4.1	0.3	(0.6)	(0.1)	(0.2)	(0.7)	0.1
Exports	6.5	4.6	1.6	2.9	5.6	5.7	5.6
Imports	13.6	5.8	2.9	2.1	4.3	3.3	4.5
Change in inventories (millions $)	(569)	1 620	5 529	5 557	9 098	7 004	9 729
Domestic demand	4.9	2.7	1.9	1.2	1.4	1.0	1.5
Real disposable income	2.3	1.6	2.1	1.5	1.5	1.4	1.5
Employment	1.4	1.5	1.2	0.8	0.9	0.3	1.2
Unemployment rate	8.0	7.5	7.3	7.3	7.1	7.4	6.9
Inflation	1.8	2.9	1.5	1.0	1.6	1.2	1.9
Before-tax profits	34.7	15.2	(2.7)	0.5	5.4	4.0	5.7
Federal balance (Public Acc., bil. $)	(33.4)	(31.7)	(26.3)	(16.2)	(15.2)	....	....
Current account (bil. $)	(60.2)	(52.3)	(66.9)	(64.2)	(54.2)	....	....

** or as noted*

Financial Forecast*

	Current 5/22/13	Q2	Q3	Q4	Q1	2013	2014
Overnight rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Prime rate	3.00	3.00	3.00	3.00	3.00	3.00	3.00
3 month T-Bills	0.99	0.95	0.98	0.98	0.98	0.98	1.21
Treasury yield curve							
2-Year	1.03	1.03	1.14	1.20	1.45	1.20	1.83
5-Year	1.38	1.36	1.49	1.65	1.94	1.65	2.52
10-Year	1.96	1.93	2.06	2.27	2.47	2.27	3.11
30-Year	2.57	2.54	2.63	2.78	2.94	2.78	3.41
USD per CAD*	0.96	0.96	0.95	0.96	0.97	0.97**	0.98**
Oil price (WTI), U.S.$*	94	93	89	90	92	93**	94**

National Bank Financial

** end of period*

*** annual average*

Hodgkins, Grant

From: Gregory, Michael <michael.gregory@Bmo.com>
Sent: Monday, June 3, 2013 10:14 AM
To: Williams, Grant; Hodgkins, Grant
Cc: Kavcic, Robert
Subject: RE: BCUC filing

All below are annual averages (a quick cut and paste job!)

	C$ per US$
2013	1.027
2014	1.011
2015	0.995
2016	1.027
2017	1.077
2018	1.100

	BoC	Gov't of Canada (bills/bonds)		
	Overnight	3 months	10 years	30 years
2013	1.00	0.98	2.04	2.66
2014	1.19	1.19	2.87	3.44
2015	1.98	1.98	3.66	4.17
2016	3.40	3.40	4.02	4.48
2017	3.50	3.50	4.31	4.72
2018	3.50	3.50	4.35	4.75

BC CPI (% chng)

2012: 1.1
2013: 0.3
2014: 1.7
2015: 2.0
2016: 2.0
2017: 2.0
2018: 2.0

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