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September 20, 2013

Via Email
Original via Mail

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

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

Response to Industrial Customers Group (ICG) 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 ICG 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, p. 1 and p. 75

FBC's proposed PBR Plan builds on the successful components of its most recent PBR plan, which was approved for 2007 – 2008 and extended for 2009 – 2011 (the 2007 Plan), with improvements to a number of elements.

The PBR mechanism proposed in this application results in rate increases that are nearly identical to those that would be likely required under cost of service regulation, before rate smoothing.

1.1 Please explain why FortisBC did not apply for an extension to the 1996 PBR Plan and the 2007 PBR Plan?

Response:

FBC has built on its past PBR experience by proposing a PBR Plan that included successful components as well as added components in areas of improvement. Table B6-9 on pages 73 and 74 of the Application provides a comparison on the proposed PBR Plan with the 2007 PBR Plan. The Company came out of its previous PBR Plans as required in order to rebase and prepare for its new Plans after a reasonable period of cost of service rate making.

1.2 Please provide the rate increases attributed to the WAX CAPA in year 2015 and in year 2016?

Response:

The rate increases attributed to the WAX CAPA in year 2015 and in year 2016 before implementation of the rate smoothing mechanism are as follows:

1. Rate increases attributed to the WAX CAPA in year 2015: 7% (approximately)
2. Rate increases attributed to the WAX CAPA in year 2016: 4% (approximately)

1.3 Please confirm that rate smoothing and the PBR Plan are not linked, and that rate smoothing could just as easily be implemented under cost of service regulation as under a PBR Plan?

Response:

Confirmed. The Rate Stabilization Deferral Mechanism could be implemented under cost-of-service regulation.

1.4 Please explain how the rates can be considered fair and reasonable when the rates in the early years of the rate smoothing proposal exceed the cost of service in those years?

Response:

FBC finds the statement that rates exceed the cost of service to be misleading. The RSDM is one of a number of deferral accounts that create timing differences in the "cost of service". For example, some of the most significant factors in determining the 2014 revenue requirements, absent the RSDM, is the Power Purchase Expense Variance Account, the Stage 1 Generic Cost of Capital proceeding impact, and the City of Kelowna Acquisition Customer Benefit Deferral Account, all of which relate to the Company's cost of service in 2013, but reduce revenue requirements for 2014.

The use of deferral accounts for such short-term timing differences is common regulatory practice. In fact mitigation of rate variability can be an objective of deferral account treatment, as stated explicitly by the Commission in Order E-15-12 where FBC was directed to bring forward a rate smoothing proposal for the Commission's approval.

There is no basis on which to conclude that the rates arising from the use of the RSDM, or any other deferral account, are not fair and reasonable. In the case of the RSDM, in fact, cumulative rates over the 2014-2018 period are lower than would be the case without the RSDM.

1.5 Please comment on whether or not the materials filed in this proceeding are sufficient for the Commission to approve rates based on cost of service regulation, assuming the Commission decides to not approve the PBR Plan?

Response:

No. FBC has not filed a cost of service application for the 2014-2018 period. The forecasts included in Sections C4 and C5 for O&M Expense and Capital Expenditures, respectively, have been provided over the 5-year period for reference purposes only. The 2015-2018 revenue requirements provided in the Application are subject to reforecasting of cost accounts annually and can not be used to set rates based on current forecasts.

If the Commission were to not approve the PBR Plan, FBC would need to re-file its revenue requirements application using a cost-of-service model for a test period to be determined.

1.6 Please comment on whether or not a cost of service application usually accompanies an application for a PBR Plan?

Response:

B&V provides the following response.

PBR only requires a starting point for prices or revenues (depending on the form of the cap). In some circumstances this starting point may not reflect current costs because of the elapsed time between the last cost of service application and the current base year. In that case a revenue requirements application would be an important element of filing a plan. Where the last cost of service review is fairly recent and still produces just and reasonable rates (with or without discrete adjustments such as added rate base) there would be no reason to require a complete cost of service proceeding and it would be inefficient to do so. One frequent example of this type of result is to update the PBR formula and extend the current Plan without the need for a cost of service application.

Further using the prior year approved as a base with adjustments was the approach taken in the last FBC PBR. As discussed in the Application at page 51 beginning at line 5:

> *"This follows the approach of FBC's 2006 Revenue Requirements, which established an O&M Base for the PBR mechanism, using incremental O&M adjustments to the previous year's approved O&M which had been determined by way of a full Cost of Service rate application and oral hearing."*

1.7 Please explain the comment "nearly identical" in the phrase "this application results in rate increases that are nearly identical to those that would be likely required under cost of service regulation'?

Response:

The statement refers to the rate increases that would result from the PBR methodology compared to the rate increases using the indicative O&M and capital expenditures under a cost of service methodology, both without the rate smoothing impact of the RSDM.

1. The cumulative rate impact during 2014-2018 under PBR without the RSDM would be: 19.3%.
2. The cumulative rate impact during 2014-2018 under cost of service without the RSDM would be: 19.2%.
3. The cumulative variance between the above two scenarios is: 0.1% during 2014-2018, which is what FBC was referring to in using *"nearly identical"* in the statement referred to above.

2014-2018 Rate Impacts with PBR but without Rate Management	**2014**	**2015**	**2016**	**2017**	**2018**
Rate Impact	-6.0%	15.3%	6.2%	1.9%	1.7%
Cumulative Rate Impact	-6.0%	8.4%	15.1%	17.3%	**19.3%**
2014-2018 Rate Impacts with Cost of Service but without Rate Management	**2014**	**2015**	**2016**	**2017**	**2018**
Rate Impact	-6.0%	15.3%	6.2%	1.9%	1.6%
Cumulative Rate Impact	-6.0%	8.4%	15.1%	17.3%	**19.2%**
Variance	**2014**	**2015**	**2016**	**2017**	**2018**
Rate Impact Variance	0.0%	0.0%	0.0%	0.0%	-0.1%
Cumulative Rate Impact Variance	0.0%	0.0%	0.0%	0.0%	**-0.1%**

1.8 Please comment on whether FortisBC considers rates of BC Hydro as compared to rates of FortisBC as a significant or insignificant concern of FortisBC customers?

Response:

Yes, FBC considers this issue to be of concern to FBC's customers. The comparison of FBC's rates to BC Hydro's rates was addressed by various interveners in FBC's 2012-2013 Revenue

Requirements application. Evidence in that proceeding confirmed FBC's understanding that the higher rates do impact customer satisfaction.[1]

In considering the relevance of rate disparities, the Commission stated:[2]

> *"FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less."*

FBC believes that the PBR Plan proposed in this Application, which promotes the continuation of FBC's productivity culture and provides for regulatory efficiency, is an important element of the Company's efforts to mitigate rate increases over the term of the proposed PBR Plan.

1.9 Please file any and all documents prepared in the past five years that compare or consider FortisBC rates as compared to BC Hydro rates?

Response:

FBC respectfully submits that comparisons of its rates to BC Hydro's are outside the scope of its Revenue Requirements Application. Regarding comparisons of FBC and BC Hydro rates, the Commission stated the following in its Decision on FBC's 2012-2013 Revenue Requirements Application, Order G-110-12:

> *"FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy*

[1] Order G-110-12, page 20
[2] Ibid., page 20

objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less." (Order G-110-12, pages 20 and 21)

2.0 Reference: Exhibit B-1, Section A3, Productivity Focus – 2013 and Onward, page 14

Productivity Improvement Factors

2.1 Please provide a summary of the product improvement factors by year, where applicable, since 1996.

Response:

Please see the table below. This series of productivity improvement factors by year translates into over 30% cumulative productivity that has been absorbed into the business since 1996.

Year	Productivity Improvement Factor
1996	4%
1997	3%
1998	3%
1999	0%
2000	2%
2001	2%
2002	2%
2003	1%
2004	0%
2005	N/A
2006	N/A
2007	2%
2008	2%
2009	3%
2010	1.5%
2011	1.5%

3.0 Reference: Exhibit B-1, Section A6, Proposed Regulatory Process, page 20

Customer consultation

"FBC has discussed the proposed process with its customary intervener groups, and understands that they are not opposed to an NSP."

3.1 Please provide a record of the consultations held with the customary intervener groups (dates, participants, etc.) and provide confirmation that the consultations indicated no opposition to an NSP.

Response:

FBC does not have such a record. The discussions were in some cases a part of general conversations with interveners regarding the proposed application of FBC and/or FEI.

The statement in the preamble was not meant to suggest that the utility carried out specific consultations for the purpose of canvassing this issue. Rather, FBC's informal understanding that interveners may be agreeable to an NSP led to its proposed regulatory timetable in Section A6, which included a Procedural Conference for the purpose of definitively setting out the process for review.

4.0 Reference: Exhibit B-1, Section B5, Table B5-1, page 36

Jurisdictional Comparison

4.1 Please provide the actual X factor used for each year as applicable (for instance, since 2008 for Union Gas, and since 2007 for Gaz Metro) in each of the jurisdictions listed in Table B5-1.

Response:

Please refer to the response to the BCUC IR 1.7.2 for the approved X-factor values used in each plan.

5.0 Reference: Exhibit B-1, Section B6, Term, page 41

Significant events

5.1 Please discuss whether significant recent and near future events provide more incentive to choose a shorter PBR term than five years because of the uncertainty of the effects of those events on the business, and the disadvantage customers are at by not having as much information as the Company regarding the effects those events may have on the business. For instance, significant recent and near future events include the acquisition of the City of Kelowna, the renegotiation of the BC Hydro Power Purchase Agreement, and the commercial operation of the Waneta Expansion Project.

<u>Response:</u>

The issue of asymmetric information is always present with either cost of service or PBR. That is part of the reason for building in symmetric safeguards for all stakeholders. The purchased power negotiation does not impact the PBR because it is a flow through item. As stated in B&V's report (Appendix D1 – Page 36), "while there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders." B&V also states that the "the five year plan seems to be reasonable so long as other portions of the plan are reasonable."

5.2 Please discuss the relative merits of a shorter term PBR with an extension mechanism as compared to the longer term PBR proposed by FortisBC in this Application.

<u>Response:</u>

Five years represents the typical period for a PBR Plan, and achieves a balance between providing additional incentive over what would otherwise be the case with a typical cost of service test period / regulatory efficiency, and timely rebasing and oversight. The combination of the PBR Plan elements including earnings sharing, efficiency carry over, off-ramps and reopeners and a transparency feature of annual reviews creates a reasonable set of mechanism to protect stakeholders from unreasonable outcomes in either direction.

6.0 Reference: Exhibit B-1, p. 45 and p. 47

Different approaches can be used to set the X-Factor. These can be classified into two major groups: "Pure TFP approach" and "Hybrid Judgement-based approach".

B&V concludes that the downward trend of TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output. B&V expects that this trend will continue during FBC's proposed five year PBR term.

6.1 Please comment on the merits of each approach to set the X-Factor in circumstances of significant changes in costs?

Response:

B&V provides the following response.

The pure TFP approach is used when there is no consumer dividend or stretch factor involved and the plan consists of only a price or revenue cap. See for example the FERC oil pipeline price cap. Under that cap, the price is adjusted annually by a pure I-X adjustment where X is currently negative. The only other provision of the mechanism is the ability for a pipeline to opt out by filing a full cost of service based application showing that the formula rate is not just and reasonable or customers may file a complaint that the result is not just and reasonable.

As other provisions are added to the Plan, the Hybrid Judgement-based approach is necessary as in this case. The TFP approach measures all aspects of input and output growth. To the extent that CPCN costs are removed for example, there is no way to estimate TFP consistent with this treatment. The only option for developing an X-Factor under that circumstance in conjunction with other elements of the Plan is a Hybrid approach as proposed by FBC. In fact, there is reason to believe that the hybrid approach in conjunction with negotiated settlements produces reasonable outcomes in an efficient manner.

6.2 Please identify circumstances when neither approach to setting the X-factor is effective?

Response:

B&V provides the following response.

As discussed in Appendix D-1, there are many reasons why estimates of TFP could be wrong. In fact, there is debate among the practitioners about any number of issues. Since the pure TFP by necessity must assume that the TFP is an accurate measure of productivity to meet the test of a just and reasonable rate it is likely that pure TFP is only suitable when there is broad agreement that the results are reasonable. Essentially, the development of the X-Factor under the Hybrid approach is the most viable option. X-Factor would not work where a utility was adding a large generating unit to rate base during the period since there is no practical way to reflect this type of lumpy addition absent a cost of service reset. (This is why a complete PBR Plan includes some elements of cost of service as discussed in the filing.)

6.3 Please comment on whether or not either approach is effective at a time when the specific utilities rates are forecast to increase faster than inflation and faster than sales and the number of customers?

Response:

B&V provides the following response.

There is no reason that the Hybrid approach cannot work under the circumstances described. The X-Factor would be set at a negative value. Sales growth has no impact on the X-Factor since the only cost driven by sales would be outside of the I-X formula. The implication of this situation is that even for an efficient utility, rates will increase faster than the rate of inflation. See for example the current FERC approved oil pipeline price cap formula.

6.4 Please comment on whether or not industry wide TFP estimation can reasonably be applied to estimate the X-Factor for a specific utility that has seen a steep decline in productivity?

Response:

B&V provides the following response.

The question requires an understanding of the reason for the decline in productivity for the individual utility. If the reason for the decline is common among all utilities' infrastructure replacement programs for example, the TFP will reflect the central tendency for the industry and the specific utility will have rates held to this measure. If the decline in productivity is the result of declining output because of macro-economic conditions such as loss of manufacturing and associated jobs, it is still possible for the X-Factor to be adjusted to reflect that reality. The industry average TFP would not apply. It would mean a higher negative X-Factor than for the industry as a whole would be required. This approach may evolve into a multi-year rate case plan with the I-X formula adjusting rates to track the underlying costs.

6.5 Please calculate and comment on whether or not FortisBC has seen a decline since 1993 in productivity as measured by revenue requirements with and with no adjustment for BC CPI as the input as compared to sales and/or the number of customers as the output?

Response:

Using revenue requirements is not a reasonable means for measuring productivity since revenue requirement is impacted by a number of factors exogenous to the control of management.

- First, revenue requirement includes costs such as purchased power expense that is a flow through item that is subject to uncontrollable external influences such as BC Hydro rate increases or market power prices.
- Second, changes in laws and regulations impose added costs that increase revenue requirements apart from productivity. Some externally induced and non-controllable changes have also reduced revenue requirements over the last two decades, such as declining interest rates and allowed ROE, and reductions in income taxes. In fact, it is likely that externally imposed cost changes have been quite significant over the period from 1993.
- Third, costs over time are impacted by technological changes in the economy in general. A good example is seen in the cost of electric transformers which for a long period were relatively the same costs because of better manufacturing technology. However, over the last few years transformer costs have increased dramatically as a result of much higher costs for inputs such a copper. This type of change impacts revenue requirements far beyond the rate of general inflation but is beyond the control of the utility.

Making a reasonable assessment of the Company's productivity in the two decades since 1993 using revenue requirements and selected measures of output would require adjusting for or separating these non-controllable and external cost impacts from those items over which the utility has some degree of control. Since these external influences over twenty years have been numerous FBC believes that trying to draw conclusions from an exercise of this nature would be questionable.

6.6 Please calculate and comment in whether or not BC Hydro has seen a change since 2003 in productivity as measured by revenue requirements with and with no adjustment for BC CPI as the input as compared to sales and/or the number of customers as the output?

Response:

Please refer to the response to ICG IR 1.6.5 above explaining that using revenue requirements is not a reasonable means for measuring productivity.

Furthermore FBC does not have the information on BC Hydro's annual revenue requirements since 2003 that would be required to prepare the requested analysis.

7.0 Reference: Exhibit B-1, Section B6, Table B6-5, page 53

Forecast O&M Formula Results

7.1 Please provide the Company's performance since 2007 in the same format as Table B6-5.

Response:

Please see the table below:

Particulars	2007	2008	2009	2010	2011	2012
Average Number of Customers	105,069	108,722	110,286	111,552	112,756	113,588
% Change in Customers	4.03%	3.48%	1.44%	1.15%	1.08%	0.74%
Composite I Factor	2.41%	3.20%	1.43%	2.29%	2.07%	1.60%
Productivity X-Factor	**-0.50%**	**-0.50%**	**-0.50%**	**-0.50%**	**-0.50%**	**-0.50%**
I - X Mechanism (1+I-X)	101.91%	102.70%	100.93%	101.79%	101.57%	101.10%
Net Inflation Factor (1+I-X)*(1+Customer Growth %)	106.02%	106.27%	102.38%	102.96%	102.67%	101.85%
Formulaic O&M	**39,103**	**41,555**	**42,545**	**43,803**	**44,971**	**45,801**
Add: O&M tracked outside of Formula						
Pension/OPEB (O&M portion)	2,917	2,542	3,165	3,749	4,670	5,951
CEP Decision G-195-10 from Capital to O&M	-	-	-	-	3,518	3,169
Mandatory Reliability Compliance	-	-	-	-	1,016	1,179
Trail Office Lease	600	753	1,212	1,212	1,212	1,212
HST Adjustment	-	-	-	-	(151)	-
PLP Ongoing O&M	1,089	-	-	-	-	-
PLP Onetime Transition Cost	251	-	-	-	-	-
Total Theoretical O&M	**43,960**	**44,850**	**46,922**	**48,764**	**55,236**	**57,312**
Total Actual O&M	**43,001**	**44,725**	**46,017**	**46,148**	**53,076**	**53,542**
Variance from Actual	**959**	**125**	**905**	**2,616**	**2,160**	**3,770**

8.0 Reference: Exhibit B-1, Section B6, Figure B6-2, page 54

Forecast O&M Formula Results

8.1 Please explain how the 0.5 percent productivity X-factor is a "stretch" target given the actual forecast O&M amount is expected to be lower than the formula provided by the PBR mechanism.

<u>Response:</u>

The "stretch" factor, in the context of PBR, doesn't involve a comparison of FBC's O&M forecast and FBC's O&M formula as the question appears to assume. Rather, a stretch factor typically refers to a comparison of the formula to the industry TFP.

In choosing to propose an X-Factor that includes greater productivity than the TFP, FBC is undertaking to perform better than the industry, based on the adoption of the PBR model in its proposed form. The stretch factor applies to both O&M and capital. It is an aggregate approach to the revenue adjustment that applies to total revenue consisting of both the revenue requirement for capital and for O&M. Thus the Company will be required to manage within the stretch factor a combination of both O&M and capital revenue requirements.

9.0 Reference: Exhibit B-1, Section B6, Table B6-7, page 58

PBR Capital Formula Inputs and 5-Year Forecasts

9.1 Please provide the Company's performance since 2007 in the same format as Table B6-5.

Response:

FBC does not believe the calculation requested provides any information that is helpful in evaluating the proposed PBR mechanism moving forward. Unlike O&M in the 2007-2011 PBR Plan, which was set according to a formula similar to that proposed in this Application, the Company's capital expenditures for 2007-2011 were not formulaic and were based on detailed project-by-project analysis that was reviewed and approved through the Revenue Requirements / Capital Expenditure Plan applications. As well, the 2006 starting Base Capital of $71.7 million is higher than the 2013 starting Base Capital.

The capital calculation (based on Table B6-7) is shown below.

Particulars	2006	2007	2008	2009	2010	2011	2012
Average Number of Customers	[redacted]	105,069	108,722	110,286	111,552	112,756	113,588
% Change in Customers		4.03%	3.48%	1.44%	1.15%	1.08%	0.74%
Composite I Factor		2.41%	3.20%	1.43%	2.29%	2.07%	1.60%
Productivity X-Factor		-0.50%	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
I - X Mechanism (1+I-X)		101.91%	102.70%	100.93%	101.79%	101.57%	101.10%
Net Inflation Factor (1+I-X)*(1+Customer Growth %)		106.02%	106.27%	102.38%	102.96%	102.67%	101.85%
Formulaic Capital		**76,020**	**80,787**	**82,712**	**85,158**	**87,429**	**89,043**
2006 Base Capital	**71,704**						
Add: Major Capital & Pension tracked outside of Formula							
Pension/OPEB (Capital portion)	4,119	3,713	3,236	4,029	4,774	5,944	6,447
Major Capital Projects	18,372	58,898	42,396	45,774	75,455	27,757	10,301
Total Theoretical Capital	**94,195**	**138,631**	**126,419**	**132,514**	**165,388**	**121,130**	**105,791**
Total Actual Capital	**94,195**	**129,189**	**99,587**	**99,169**	**130,491**	**76,209**	**52,392**
Variance from Actual	**-**	**9,442**	**26,832**	**33,345**	**34,897**	**44,921**	**53,399**

9.2 Please explain why 2013 should be considered a "base capital" year, and provide a capital plan summary showing forecast, approved and actual capital by year since 2007 in the same format as Table 1.1 in Exhibit B-1 for the FortisBC Inc. Application for Approval of 2011 Capital Expenditure Plan.

Response:

Recognizing that the Capital Expenditure Base for the 2014-2018 formula should be a Capital Expenditure number which has undergone a full review through an oral public hearing, FBC has used the 2013 Approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula ($101.970 million) which becomes $49.18 million when adjusted as detailed in Table C5-2.

Similar to the methodology used to arrive at the 2013 O&M Base for PBR, adjustments were made to the 2013 Approved capital to arrive at the "2013 Capital Base". These include:

- Adjustment for non-recurring major projects; and
- Adjustments to include 2013 actual "non-controllable" items equivalent to those included in the Base O&M calculation.

These adjustments determine the starting point or base for capital expenditures in the upcoming PBR period as shown on Table B6-6: 2013 Base Capital and in Table B6-7: PBR Capital Formula Inputs and 5-Year Forecasts ($49,180,000).

FBC's response to ICG IR 1.9.1 explains that capital expenditures during the 2007 PBR Plan are not suitable for determining the level of capital expenditures under the proposed PBR formula.

The requested table consistent with the format of Table 1.1 from the 2011 Capital Expenditure Plan is provided below:

	2007		2008		2009		2010		2011		2012		2013		2014	2015	2016	2017	2018
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
										($000s)									
Generation	4,665	4,489	5,727	4,915	6,225	6,974	3,746	3,788	3,594	2,463	5,015	4,959	2,623	2,750	$2,734	$2,759	$2,829	$2,860	$2,581
Generation Major Projects	16,994	15,915	13,352	11,280	15,310	12,695	16,322	14,743	15,330	15,080	2,935	2,927		450			3,688	14,476	8,375
Transmission and Stations	15,643	19,715	9,961	11,104	18,497	10,986	13,950	13,498	10,079	12,970	19,787	9,210	8,212	18,240	10,508	10,688	6,688	8,592	12,182
Transmission and Stations Major Project	48,762	49,353	56,221	35,857	41,363	39,000	87,679	67,150	18,675	15,532	10,892	7,992	15,258	12,781	5,259		1,848	7,941	21,317
Distribution	27,006	38,486	28,432	36,492	35,964	30,799	34,470	31,291	31,549	26,434	35,112	25,994	34,810	35,194	$25,088	$25,235	$27,733	$27,898	$29,329
City of Kelowna Adquisition														37,766					
Telecommunications, Scada and Protection and Control	5,115	1,407	2,719	3,130	2,190	2,639	2,163	2,220	3,587	4,452	1,257	1,722	1,173	1,173	$1,242	$1,267	$2,007	$2,047	$1,235
Telecommunications Major Project															4,771				
General Plant (Other)	15,475	14,377	8,522	8,801	9,916	9,630	9,086	9,348	10,190	10,811	13,799	9,834	9,387	11,589	$9,113	$9,575	$12,073	$8,053	$7,800
Other Major Projects									503	623	9,368	2,042	48,056	23,834	25,536	26,506	583	741	604
Subtotal - Plant and Equipment	133,660	143,742	124,934	111,579	129,465	112,723	167,416	142,038	93,507	88,365	98,165	64,680	119,519	143,777	84,251	76,031	57,449	72,607	83,423
Demand Side Management	2,474	5,818	2,355	1,858	3,667	2,396	3,952	2,656	7,842	4,349	7,731	5,231	7,878	5,501	2,251	2,379	2,362	2,400	2,445
Subtotal - Additions	136,134	149,560	127,289	113,437	133,132	115,119	171,368	144,694	101,349	92,714	105,896	69,911	127,397	149,278	86,502	78,410	59,811	75,007	85,868
Cost of Removal	2,999	2,999	5,025	5,025	4,502	4,502	4,941	7,872	2,781	5,267	4,346	3,710	3,430	6,039	4,517	2,676	2,822	2,981	3,952
Sub-total	139,133	152,559	132,314	118,462	137,634	119,621	176,309	152,566	104,130	97,981	110,242	73,621	130,827	155,317	91,019	81,086	62,633	77,988	89,820
Loadings	-16,825	-17,552	-17,071	-17,015	-17,549	-18,057	-19,262	-19,419	-17,610	-17,423	-19,462	-15,998	-20,976	-16,623					
Total	122,308	135,007	115,243	101,447	120,085	101,564	157,047	133,147	86,520	80,558	90,780	57,623	109,851	138,694	91,019	81,086	62,633	77,988	89,820

Note: 2014 – 2018 expenditures are presented net of loadings and AFUDC. Minor differences due to rounding.

9.3 Please repeat the analysis in the previous question separating out and identifying the non-recurring capital for each year.

Response:

The analysis provided in the response to ICG IR 1.9.1 excludes Major Projects from the formula calculation. The Major Projects are highlighted in the following table.

	2007		2008		2009		2010		2011		2012		2013		2014	2015	2016	2017	2018
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	($000s)																		
Generation	4,665	4,489	5,727	4,915	6,225	6,974	3,746	3,788	3,594	2,463	5,015	4,959	2,623	2,750	$2,734	$2,759	$2,829	$2,860	$2,581
Generation Major Projects	16,994	15,915	13,352	11,280	15,310	12,695	16,322	14,743	15,330	15,080	2,935	2,927		450			3,688	14,476	8,375
P1U1 Upgrade & Life Extension		118																	
P1U3 Upgrade & Life Extension		7,980																	
P3U1 Life Extension		3,160																	
P3U3 Life Extension		3,164																	
P3U2 Rebuild & Life Extension		1,493																	
Lower Bonnington Unit 3 Upg. & Life Extension	7,377		0	430															
South Slocan Unit 1 Life Extension & Turbine	8,747		3,149	2,433	7,832	8,135	3,261	1,591	42										
South Slocan Unit 3 Life Extension	870		9,322	7,714	2,051	1,949													
South Slocan Completion					940		1,598												
South Slocan Unit 2 Botton Ring Rebuild & Life Extension			0	53															
Corra Linn Unit 1 Life Extension			881	650	4,487	2,611	8,476	9,647	2,507	2,990		46							
Corra Linn Unit 2 Life Extension							2,987	3,505	12,781	12,090		2,600		450					
Corra Linn Unit 3 Completion												281							
Corra Linn Spillway Concrete and Spill Gate Rehabilitation																		$6,968	$728
Upper Bonnington Old Unit Repowering Ph. 1																	$3,688	$7,508	$7,647
Transmission and Stations	15,643	19,715	9,961	11,104	18,497	10,986	13,950	13,498	10,079	12,970	19,787	9,210	8,212	18,240	10,508	10,688	6,688	8,592	12,182
Transmission and Stations Major Project	48,762	49,353	56,221	35,857	41,363	39,000	87,679	67,150	18,675	15,532	10,892	7,992	15,258	12,781	5,259		1,848	7,941	21,317
Okanagan Transmission Reinforcement	2,997	3,838	13,631	3,418	30,341	21,503	74,378	55,715	16,056	12,821	2,049	3,825							
Big White 138 Kv Line & Substation	9,969	9,666	7,183	7,380	0	110													
Ellison Dist Source	13,319	1,744	12,990	7,810	1,734	5,608			693										
Black Mountain Dist Source	497	476	9,660	6,811	4,517	7,196													
NkMip Substation	12,489	15,251	0	144	0														
Kettle Valley	9,491	18,378	2,605	4,802		473													
Ootischenia Substation			5,340	5,492	389														
Benvoulin Substation			4,812	0	4,382	4,110	13,301	11,435	0	993									
Environmental Compliance (PCB Mitigation)									1,926	1,718	8,843	4,167	11,408	12,781	5,259				
New Ruckles Substation																	$1,848	$1,885	$1,925
Grand Forks Transformer Addition - Option 1 - Single Breaker																		$1,857	$1,895
Kelowna Bulk Capacity Addition													3,850					4,199	5,890
New Central Okanagan Station																			11,607
Distribution	27,006	38,486	28,432	36,492	35,964	30,799	34,470	31,291	31,549	26,434	35,112	25,994	34,810	35,194	$25,088	$25,235	$27,733	$27,898	$29,329
City of Kelowna Adquisition														37,766					
Telecommunications, Scada and Protection and Control	5,115	1,407	2,719	3,130	2,190	2,639	2,163	2,220	3,587	4,452	1,257	1,722	1,173	1,173	$1,242	$1,267	$2,007	$2,047	$1,235
Telecommunications Major Project															4,771				
Grand Forks to Warfield Fibre Installation															4,771				
General Plant (Other)	15,475	14,377	8,522	8,801	9,916	9,630	9,086	9,348	10,190	10,811	13,799	9,834	9,387	11,589	$9,113	$9,575	$12,073	$8,053	$7,800
Other Major Projects									503	623	9,368	2,042	48,056	23,834	25,536	26,506	583	741	604
Central Warehousing											0	1,634							
Okanagan Long Term Solution										190	29	48	76						
Advanced Metering Infrastructure											4,137		27,931	13,834	16,765	18,233	583	741	604
Kootenay Long Term Facilties Strategy									503	433	5,202	360	10,049		$8,771	$8,273			
Trail Office Lease Purchase													10,000	10,000					
Subtotal - Plant and Equipment	133,660	143,742	124,934	111,579	129,465	112,723	167,416	142,038	93,507	88,365	98,165	64,680	119,519	143,777	84,251	76,031	57,449	72,607	83,423
Demand Side Management	2,474	5,818	2,355	1,858	3,667	2,396	3,952	2,656	7,842	4,349	7,731	5,231	7,878	5,501	2,251	2,379	2,362	2,400	2,445
Subtotal - Additions	136,134	149,560	127,289	113,437	133,132	115,119	171,368	144,694	101,349	92,714	105,896	69,911	127,397	149,278	86,502	78,410	59,811	75,007	85,868
Cost of Removal	2,999	2,999	5,025	5,025	4,502	4,502	4,941	7,872	2,781	5,267	4,346	3,710	3,430	6,039	4,517	2,676	2,822	2,981	3,952
Sub-total	139,133	152,559	132,314	118,462	137,634	119,621	176,309	152,566	104,130	97,981	110,242	73,621	130,827	155,317	91,019	81,086	62,633	77,988	89,820
Loadings	-16,825	-17,552	-17,071	-17,015	-17,549	-18,057	-19,262	-19,419	-17,610	-17,423	-19,462	-15,998	-20,976	-16,623					
Total	122,308	135,007	115,243	101,447	120,085	101,564	157,047	133,147	86,520	80,558	90,780	57,623	109,851	138,694	91,019	81,086	62,633	77,988	89,820

Note: 2014 – 2018 expenditures are presented net of loadings and AFUDC. Minor differences due to rounding.

10.0 Reference: Exhibit B-1, Section B6, page 60
Addressing Uncontrollable Costs/Revenues Outside Formula

10.1 Please discuss how FortisBC's allowed rate of return incorporates an element of risk-adjusted return to account for the risk of uncontrollable costs. Please discuss how and why such return-adjusted uncontrollable costs would be accommodated in a PBR regime but not in a standard revenue requirements environment.

<u>Response:</u>

FBC is not clear on what is specifically meant by the question, but understands it to relate generally to how the risk of uncontrollable costs differs under cost of service regulation and PBR.

Certain of FBC's uncontrollable costs are addressed through deferral accounts to eliminate the potential for windfall gains for either the Company or customers. The Commission's determinations regarding cost of capital in BC, including the recent Stage 1 GCOC decision, accounted for the presence of deferral accounts and the potential for these accounts to mitigate short-term earnings risk. Under the proposed PBR Plan, the focus is on controllable costs, not uncontrollable costs. FBC is proposing to maintain deferral accounts for uncontrollable items, and there a small number of items tracked outside of the PBR formula to account for the fact that they are not easily forecasted. The additional risk to the Company associated with PBR is related to managing controllable costs over a longer time horizon to a formulaic amount, rather than being related to the treatment of uncontrollable costs.

11.0 Reference: Exhibit B-1, Section B6, page 66

Enhancing the Effectiveness of the FEI 2004-2009 ECM

11.1 Please provide a formulaic and numerical example of the efficiency carry-over mechanism and provide a working spreadsheet model showing the effect on following years' rates of return, including the years following the PBR term.

<u>Response:</u>

Please refer to Attachment 59.3 provided in response to BCUC IR 1.59.3, which contains a working spreadsheet of an updated version of the illustrative ECM example originally included in the Application at Appendix D5, page 3. As with Appendix D5, the example provided in Attachment 59.3 to the response to BCUC IR 1.59.3 is illustrative only and does <u>not</u> represent a projection of the efficiency initiatives or savings the Company believes it can obtain under the PBR. However an approximate benchmark to estimate return impacts of the ECM can be derived from the equity component of rate base, which is expected to be between $500 million and $550 million at the end of the five-year term of the PBR. A pre-tax ECM benefit for FBC of $700 thousand (or $525 thousand after tax) would yield an ROE increase of approximately 10 basis points.

12.0 Reference: Exhibit B-1, Section B6, Table B6-8, page 69

Proposed 2014 PBR SQIs

12.1 Please explain why FortisBC no longer considers SAIDI, SAIFI, the all injury frequency rate and the customer satisfaction index to be indicators of service quality.

Response:

FBC clarifies that since 2006, customer satisfaction has been considered to be an informational indicator. Regarding the SAIDI, SAIFI, and AIFR measures, FBC still considers them to be indicators of service quality. The only change is that FBC considers these SQIs to be informational indicators.

Please refer to the responses to BCUC IR 1.68.9 (SAIDI, SAIFI), and BCPSO IRs 1.55.2 (AIFR) and 1.56.2 (CSI) for discussion of the informational nature of these SQIs.

12.2 Please provide a table showing the actual results of all indicators listed in Table B6-8 for the last 10 years.

Response:

Please refer to the below table for a summary of the historical results of each SQI proposed in Table B6-8.

Performance Measure	
Emergency Response Time	Not tracked prior to 2007. Actual results back to 2007 provided in BCUC 1.70.1.
Telephone Service Factor	Not tracked prior to 2007. Actual results back to 2007 provided in BCUC 1.70.1.
First Contact Resolution	Results not tracked previously. New SQI that has been proposed to begin in the 2014-2018 PBR Plan.
Billing Index	Results not tracked previously. New SQI that has been proposed to begin in the 2014-2018 PBR Plan.
Meter Reading Accuracy	Not tracked prior to 2007. Actual results back to 2007 provided in BCUC 1.70.1.
SAIDI	Actual results back to 2003 included in table below.
SAIFI	Actual results back to 2003 included in table below.
All Injury Frequency Rate	Prior to 2007, the Disabling Injury Frequency Rate was tracked. Actual results for the AIFR back to 2007 and for the DIFR for 2003 to 2006 are included in table below.

Performance Measure	
Customer Satisfaction Index	Actual results for the CSI back to 2003 are included in table below, however results from 2003 to 2004 are not comparable to results from 2005 onward as the CSI survey was redesigned in 2005. Please also refer to the response to CEC IR 1.16.1.

	SAIDI	SAIFI	AIFR	CSI
2003	3.29	1.99	6.01	80.2%
2004	2.44	2.39	4.77	78.4%
2005	2.09	3.07	2.02	8.0
2006	2.93	4.19	1.80	8.5
2007	2.51	2.00	1.71	8.6
2008	2.42	2.14	2.87	8.6
2009	2.28	1.48	1.41	8.6
2010	2.84	2.27	1.72	8.8
2011	1.86	1.38	1.48	8.7
2012	1.95	1.27	1.72	8.4

13.0 Reference: Exhibit B-1, p. 71

Finding the right balance between maintaining the PBR incentives and safeguarding the ratepayers and the Company is essential in design of the earnings-based off-ramps. The trigger point (the variance between earned and approved ROE) should be substantial enough to ensure that PBR's incentive powers are maintained (this is particularly important for a single year trigger point) and at the same time small enough to safeguard against potential excessive profits or losses.

13.1 Please file the variances between earned and approved ROE since 2003?

Response:

Please refer to the table below.

	Allowed ROE	Achieved ROE	Variance (Achieved – Allowed)
2003	9.82%	10.88%	1.06%
2004	9.55%	10.70%	1.15%
2005	9.43%	9.88%	0.45%
2006	9.20%	9.94%	0.74%
2007	8.77%	9.23%	0.46%
2008	9.02%	9.28%	0.26%
2009	8.87%	9.41%	0.54%
2010	9.90%	9.65%	-0.25%
2011	9.90%	10.67%	0.77%
2012	9.90%	10.52%	0.62%

13.2 Please comment on whether or not the variances between earned and approved ROE under the proposed PBR Plan as compared to the 2007 PBR Plan and also as compared to cost of service regulation can be expected reasonably to increase or decrease?

Response:

FBC intends to pursue efficiency initiatives and achieve benefits under the proposed PBR Plan although the levels of achievement over the allowed ROE relative to the incremental ROE achieved over the allowed ROE during the 2007 PBR Plan are not known. FBC intends to work to achieve positive benefits under the PBR and may achieve higher ROEs relative to the allowed levels than it would under cost of service regulation; however customers will benefit from receiving a 50% share of the earnings above the allowed ROE during the PBR term (and ECM period) and 100% of the savings afterwards.

14.0 Reference: Exhibit B-1, Section C1, Figure C1-3, page 80

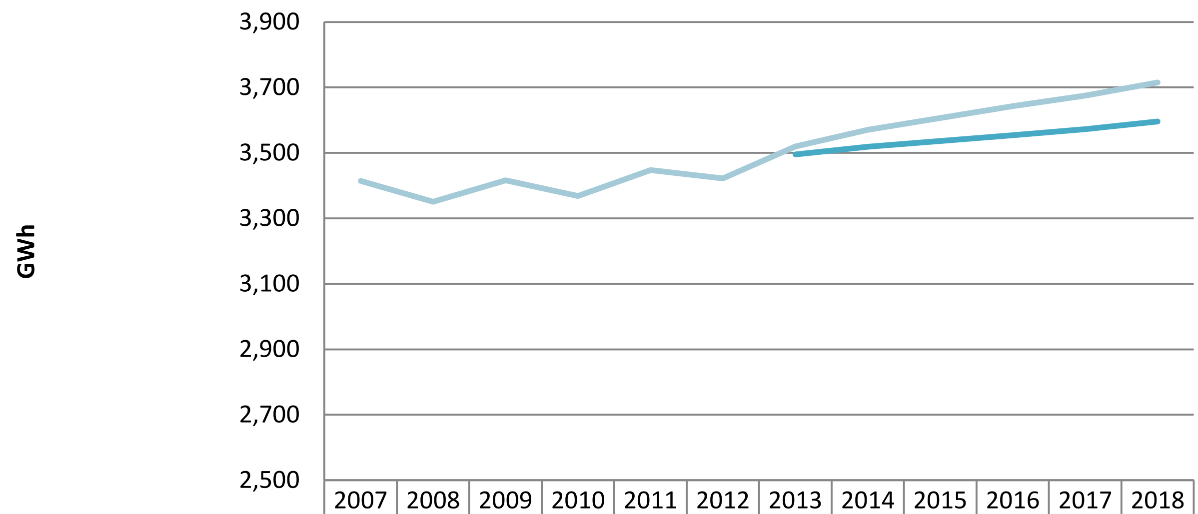
Normalized and Forecast Gross Load Energy Consumption (GWh)

14.1 Please extend Figure C1-13 to include the load growth data for 2007.

Response:

Figure C1-3 has been extended to include 2007 below:

Gross Normalized and Forecasted Energy Consumption from 2007 – 2018



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	3,414	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings							3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-0.5%	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

14.2 Please provide the forecast "before-savings" annual load growth for each year from 2013 to 2018, and compare it to the actual average load growth for the period from 2007 to 2012.

Response:

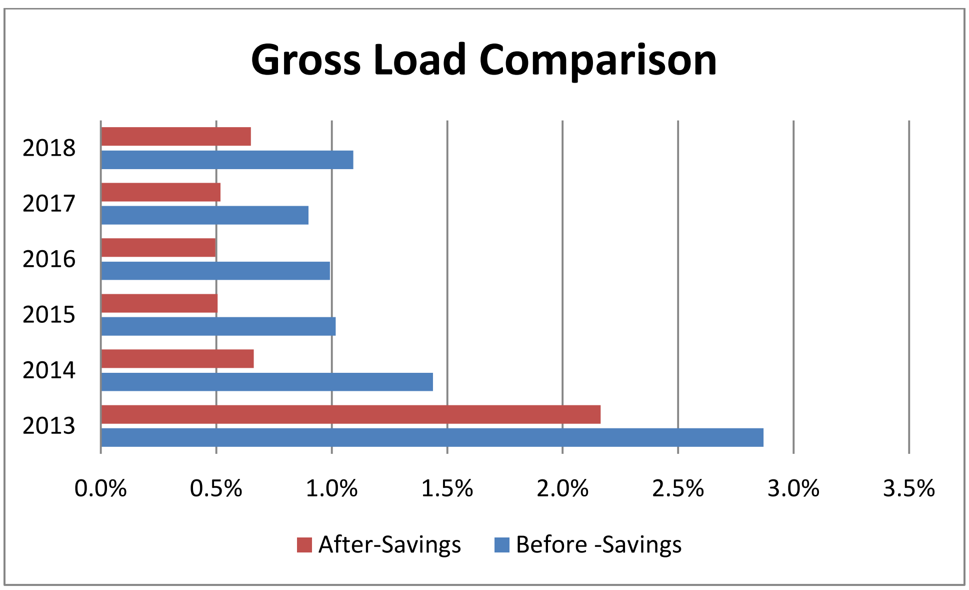
The before-savings annual gross loads growth forecast for the years 2013 to 2018 and the actual average load growth for the period of 2007 to 2012 are presented in the table below. Please note that the loads from 2007 to 2012 contain DSM, which has reduced the gross load growth, while the before-savings loads have not been reduced by incremental DSM and/or Other Savings. A more appropriate comparison would be to compare the 5 year average to the after-savings forecasted load growth which is provide below. A gross load comparison bar graph has also been added below to show that before-savings load growth is much higher than the after-savings load growth rates.

Normalized Gross Load from 2007 to 2012 (GWh)

	2007	2008	2009	2010	2011	2012	Average
Gross Load	3,414	3,351	3,416	3,369	3,447	3,422	3,403
Growth (%)	-0.5%	-1.9%	1.9%	-1.4%	2.3%	-0.7%	0.0%

2013 to 2018 Gross Load Growth

	2013	2014	2015	2016	2017	2018
Before -Savings	2.9%	1.4%	1.0%	1.0%	0.9%	1.1%
After-Savings	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%
2007 to 2012 Actual Average	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%



Note that for the purpose of this PBR, only 2014 forecast is used to establish rates. FBC will be re-forecasting each year (2015-18) and updating rates at the annual review. Therefore the response to this question is only relevant up to 2014.

14.3 Please describe and quantify the actual energy consumption reductions that the Company claims to have achieved in each year from 2007 to 2012..

Response:

Please refer to Tables 14-17 of Appendix H-2 of Exhibit B-1, which provide summary results by program, sector and annual energy savings for the period 2007-2012.

14.4 Please provide the UPC data for 2007 and comment on whether any statistically significant trend is evident in the data for the years 2007 to 2012.

Response:

Please refer to the response to ICG IR 1.15.2.

15.0 Reference: Exhibit B-1, Section C1, Figure C1-5, page 83

Normalized and Forecast Residential Before-Saving UPC (MWh)

15.1 Please confirm that the 2013 UPC is a forecast quantity.

Response:

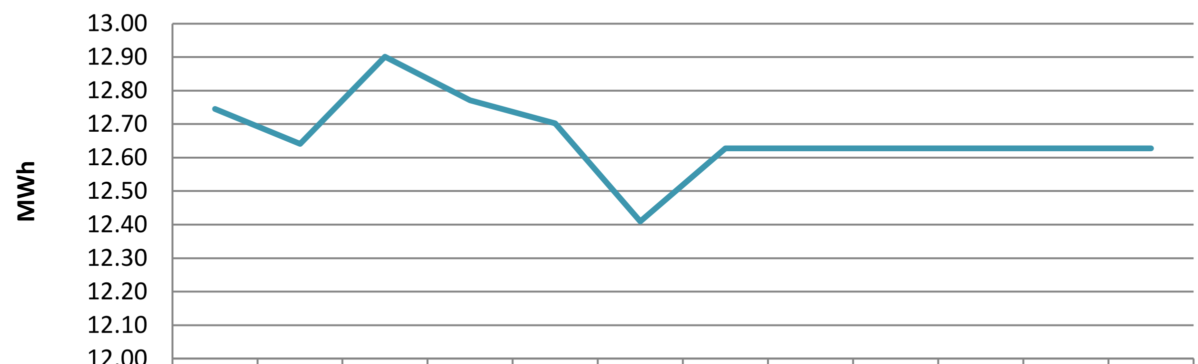
Confirmed.

15.2 Please extend Figure C1-5 to include the UPC data for 2007 and comment on whether any statistically significant trend is evident in the data for the years 2007 to 2012.

Response:

The 2007 residential UPC data has been added to Exhibit B-1, Section C1, Figure C1-5 below.

Figure 1-5: Residential Normalized UPC Forecast (MWh)

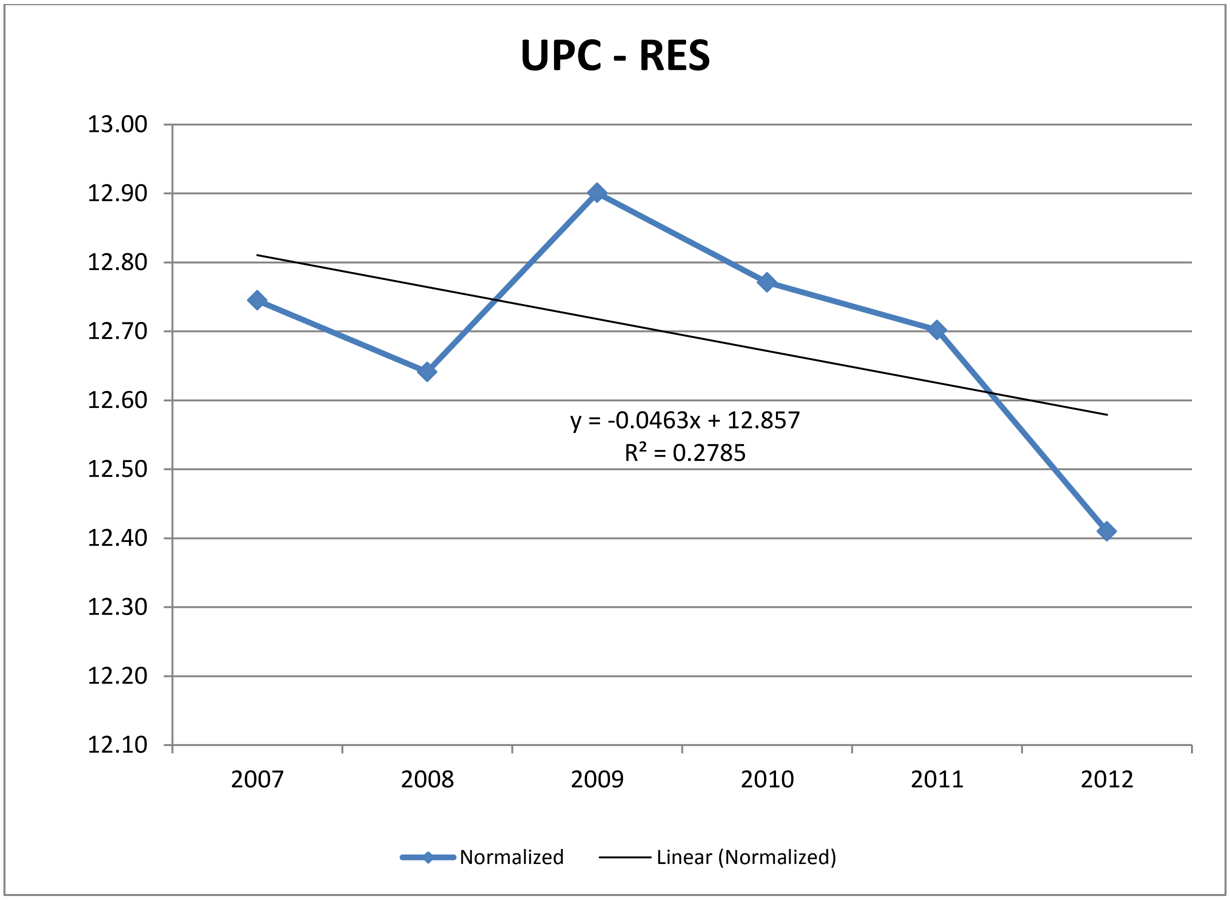


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPC	12.74	12.64	12.90	12.77	12.70	12.41	12.63	12.63	12.63	12.63	12.63	12.63
UPC Growth	5.7%	-0.8%	2.1%	-1.0%	-0.5%	-2.3%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%

A trend analysis was performed (below) and shows that there is no statically significant trend in the residential UPC from the year 2007 – 2012.

The determination is based on the F test, a common statistical test to measure the significance of a variable or a set of variables by comparing changes in the sum of squares. A high "P" value (greater than 0.05) indicates insignificance in the variable in question. In this example the "P" value is 0.282 and so we conclude it is insignificant.

2007 – 2012 Residential UPC Trend Analysis (MWh)



16.0 Reference: Exhibit B-1, Section C1, Figure C1-11, page 89

Actual and Forecast Irrigation Energy Consumption (GWh)

16.1 Please extend Figure C1-11 to include the load growth data for 2007.

Response:

Figure C1-11 has been extended to include 2007 below.

Figure C1-11: Actual and Forecast Irrigation Energy Consumption (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	48	46	49	40	40	38	43	43	43	43	43	43
After-Savings							42	42	42	42	41	41
After-Savings Growth	12.7%	-4.4%	5.9%	-17.5%	-0.1%	-5.8%	11.4%	-0.8%	-0.4%	-0.4%	-0.4%	-0.4%

16.2 Please explain why the 2008 to 2012 trend for irrigation appears to show a significantly declining trend that is not carried forward to future years.

Response:

A trend analysis on the 2008 – 2012 irrigation load showed that the declining trend is not statistically significant, with the statistical significance of the regression model being 0.06. For a trend analysis to yield significant results, we require the statistical significance to be less than 0.05. Therefore, as specified in Section 1.4.6, p. 88, Exhibit B-1, the 5-year average method was used to forecast this load.

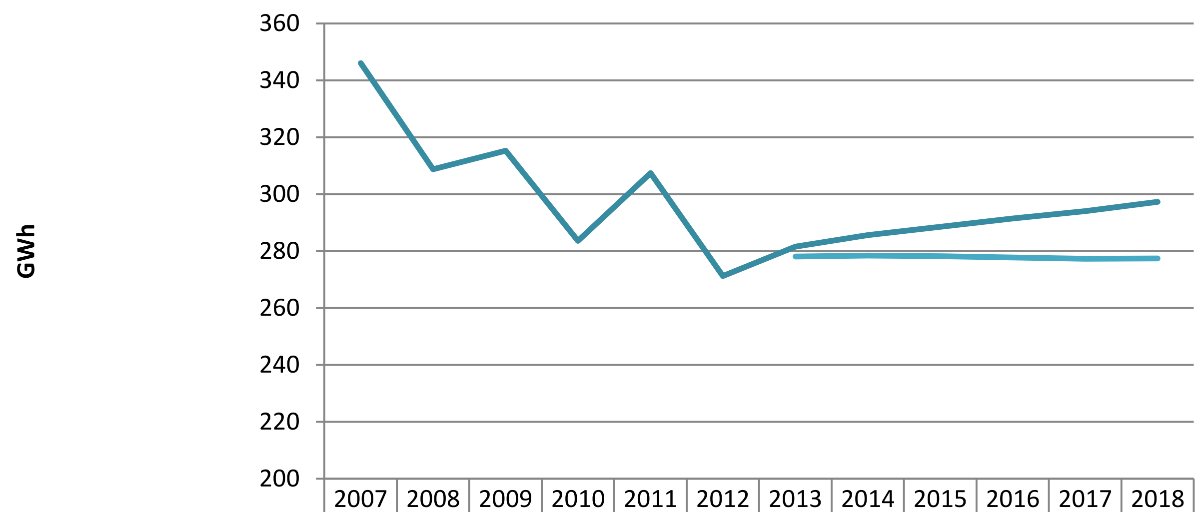
17.0 Reference: Exhibit B-1, Section C1, Figure C1-12, page 90

Normalized and Forecast Energy Losses (GWh)

17.1 Please extend Figure C1-12 to include the losses data for 2007.

<u>Response:</u>

Figure C1-12: Normalized and Forecast Energy Losses (GWh)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	346	309	315	284	307	271	282	286	289	291	294	297
After-Savings							278	278	278	278	277	277
After-Savings Growth	-5.6%	-10.8%	2.1%	-10.1%	8.4%	-11.8%	2.6%	0.1%	-0.1%	-0.1%	-0.2%	0.0%

17.2 Please explain why the 2008 to 2012 trend for losses appears to show a significantly declining trend that is not carried forward to future years.

<u>Response:</u>

The reason for losses declining during the 2008 to 2012 period is due to the Okanagan Transmission Project, which helped reduce transmission and distribution losses. This trend is not carried into forward years since the project was completed and therefore all loss reduction is now embedded in the historical load data.

18.0 Reference: Exhibit B-1, Section C1, Tables C1-1, C1-2 and C1-2, pp. 92-94

Summary Tables

18.1 Please extend Tables C1-1, C1-2 and C1-3 to include data for 2007.

Response:

Tables C1-1, C1-2 and C1-3 have been updated to include 2007 data.

Table C1-1 Normalized Energy Sales and After-Savings Forecast

Energy Sales (GWh)	Actual and Normalized						Forecast					
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	1,165	1,196	1,239	1,242	1,249	1,229	1,359	1,402	1,405	1,409	1,417	1,422
Commercial	650	661	675	660	657	681	773	813	825	837	845	860
Wholesale	878	908	908	895	910	899	677	581	584	587	590	594
Industrial	314	218	216	234	271	291	353	389	390	389	389	388
Lighting	13	13	13	14	13	13	13	13	13	13	13	13
Irrigation	48	46	49	40	40	38	42	42	42	42	41	41
Net	3,068	3,042	3,100	3,085	3,140	3,151	3,218	3,240	3,258	3,276	3,295	3,318
Losses	346	309	315	284	307	271	278	278	278	278	277	277
Gross	3,414	3,351	3,416	3,369	3,447	3,422	3,496	3,519	3,537	3,554	3,572	3,596
System Peak												
Winter Peak (MW)	704	707	704	726	702	723	743	750	756	761	767	772
Summer Peak (MW)	520	502	496	566	537	589	579	584	588	592	595	600

Table C1-2: Normalized Energy Sales and After-Savings Forecast (%)

Energy Sales (GWh)	Actual and Normalized						Forecast					
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Residential	9.5%	2.6%	3.6%	0.2%	0.6%	-1.6%	10.6%	3.2%	0.2%	0.3%	0.6%	0.4%
Commercial	5.4%	1.7%	2.2%	-2.3%	-0.4%	3.6%	13.6%	5.1%	1.5%	1.4%	1.1%	1.8%
Wholesale	-10.3%	3.4%	0.0%	-1.4%	1.6%	-1.2%	-24.7%	-14.1%	0.5%	0.5%	0.5%	0.5%
Industrial	-9.8%	-30.6%	-1.0%	8.3%	15.9%	7.4%	21.5%	10.2%	0.1%	-0.1%	-0.2%	-0.1%
Lighting	1.9%	4.5%	-0.8%	8.9%	-8.6%	1.9%	-2.4%	-2.8%	0.0%	0.0%	0.0%	0.0%
Irrigation	12.7%	-4.4%	5.9%	-17.5%	-0.1%	-5.8%	11.4%	-0.8%	-0.4%	-0.4%	-0.4%	-0.4%
Net	0.2%	-0.8%	1.9%	-0.5%	1.8%	0.3%	2.1%	0.7%	0.6%	0.5%	0.6%	0.7%
Losses	-5.6%	-10.8%	2.1%	-10.1%	8.4%	-11.8%	2.6%	0.1%	-0.1%	-0.1%	-0.2%	0.0%
Gross	-0.5%	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%
System Peak												
Winter Peak (MW)	-3.9%	0.5%	-0.4%	3.1%	-3.3%	2.9%	2.8%	1.0%	0.8%	0.7%	0.8%	0.6%
Summer Peak (MW)	5.5%	-3.4%	-1.3%	14.1%	-5.2%	9.8%	-1.8%	0.9%	0.7%	0.7%	0.6%	0.8%

Table C1-3: Actual and Forecast Year-End Customer Count

	Actual						Forecast					
Energy Sales (GWh)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	93,647	95,502	96,565	97,883	98,795	99,228	112,740	113,589	114,521	115,508	116,544	117,600
Commercial	11,010	11,216	11,308	11,419	11,525	11,811	13,589	13,847	14,114	14,368	14,576	14,879
Wholesale	7	7	7	7	7	7	6	6	6	6	6	6
Industrial	38	36	33	35	36	39	48	48	48	48	48	48
Lighting	1,992	1,910	1,874	1,830	1,803	1,739	1,742	1,742	1,742	1,742	1,742	1,742
Irrigation	1,030	1,048	1,066	1,075	1,092	1,091	1,091	1,091	1,091	1,091	1,091	1,091
Total Direct	107,724	109,719	110,853	112,249	113,258	113,915	129,216	130,323	131,521	132,763	134,007	135,366
Annual Change By Customer Class (%)												
Residential	5.0%	2.0%	1.1%	1.4%	0.9%	0.4%	13.6%	0.8%	0.8%	0.9%	0.9%	0.9%
Commercial	7.0%	1.9%	0.8%	1.0%	0.9%	2.5%	15.1%	1.9%	1.9%	1.8%	1.5%	2.1%
Wholesale	-12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	-14.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.7%	-5.3%	-8.3%	6.1%	2.9%	8.3%	23.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Lighting	4.6%	-4.1%	-1.9%	-2.3%	-1.5%	-3.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Irrigation	3.3%	1.7%	1.7%	0.8%	1.6%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Direct	5.2%	1.9%	1.0%	1.3%	0.9%	0.6%	13.4%	0.9%	0.9%	0.9%	0.9%	1.0%

19.0 Reference: Exhibit B-1, Section C2, Table C2-1, page 96

Total Power Purchase Expense

19.1 Please provide a table with the approved and actual power purchase and gross load for the last 10 years, and identify the amount of incentive/cost flowing from the difference between approved and actual power purchase costs for each year that a PBR mechanism was in place.

Response:

Please note that sharing dynamics of the Power Purchase Expense (PPE) differential through the incentive sharing mechanism varied during the last ten years as follows:

2003-2005: PPE Variance Sharing by Customer: 65% of the first $1 million & 75% of the remainder of the PPE variance was flowed through to customers. This was also subject to other adjustments;

2006: PPE Variance Sharing by Customer: 100% of PPE variance was flowed through to customers;

2007-2011: PPE Variance Sharing by Customer: 50% of the PPE variance was flowed through to customers through the ROE sharing mechanism applicable during the period;

2012: PPE Variance Sharing by Customer: 100% of the PPE variance was flowed through to customers.

For the sake of uniformity of comparison, the table below has been created that shows theoretical Power Purchase sharing amounts under 50% and 100% flow through assumptions.

The actual customer shares of the PPE variance during 2007-2012 are highlighted in the Table below for clarity. Please note that a negative sharing volume indicates flow through to the customer that will reduce revenue requirement.

Year	Approved Gross Load	Actual Gross Load	Approved PPE	Actual PPE	Pre Tax Variance PPE	Actual Tax Rate	Applicable Income Tax Component	Post Tax Variance PPE	Power Purchase @ 100% Flowthrough		Power Purchase @ 50% Flowthrough		Remarks
									Company	Customer	Company	Customer	
	(GWh)		($000s)			%	($000s)						
2003	3,146	3,182	60,635	58,436	(2,199)	37.32%	821	(1,378)	-	(1,378)	(689)	(689)	PPE Sharing Formula 2003-2006: 65% of the first $1 million & 75% of the reminder, subject to other adjustments
2004	3,218	3,227	61,366	59,014	(2,352)	35.62%	838	(1,514)	-	(1,514)	(757)	(757)	
2005	3,297	3,346	59,451	60,404	953	34.87%	(332)	621	-	621	310	310	
2006	3,401	3,405	65,067	67,576	2,509	34.12%	(856)	1,653	-	**1,653**	826	826	2006 PPE Sharing: 100% to Customer
2007	3,453	3,410	69,260	66,629	(2,631)	34.12%	898	(1,733)	-	(1,733)	(867)	**(867)**	PPE Sharing 2007-2011: PPE sharing during 2007 to 2011 was 50% / 50% for the Customer & the Shareholder through the ROE Sharing Mechanism
2008	3,396	3,400	68,538	66,010	(2,528)	31.00%	784	(1,744)	-	(1,744)	(872)	**(872)**	
2009	3,401	3,479	70,944	70,776	(168)	30.00%	50	(118)	-	(118)	(59)	**(59)**	
2010	3,509	3,326	80,408	71,964	(8,444)	28.50%	2,407	(6,037)	-	(6,037)	(3,019)	**(3,019)**	
2011	3,543	3,451	81,212	71,519	(9,693)	26.50%	2,569	(7,124)	-	(7,124)	(3,562)	**(3,562)**	
2012	3,490	3,413	87,149	75,999	(11,150)	25.00%	2,788	(8,363)	-	**(8,363)**	(4,181)	(4,181)	2012 PPE Sharing: 100% to Customer

20.0 Reference: Exhibit B-1, Section C2, Tables C2-2 and C2-3, pp. 98-99

Total 2012 and 2013 Power Purchase Expense

20.1 Please confirm that if the proposed new PPA was in effect and FortisBC's power nominations under the new PPA were the quantities associated with the approved amounts of $51,426,000 and $54,482,000 (in 2012 and 2013 respectively) and the new PPA minimum take provisions would require greater BC Hydro purchases and less market purchases than shown in Tables C2-2 and C2-3.

<u>Response:</u>

If it assumed that the New PPA was in effect and FBC's Annual Energy Nomination was equal to the quantities associate with the approved amounts, then the minimum take provisions would mean that FBC would have been required to take or pay 75% of those amounts. Under those assumptions greater BC Hydro purchases and less market purchases than shown in Tables C2-2 and C2-3 would have been required. However, as discussed in the response to ICG IR1.20.2, if the full flexibility available to FBC under the New PPA is assumed, the volumes are likely to have been similar.

20.2 Please re-cast Tables C2-2 and C2-3 with the assumption that the proposed new PPA was in effect and FortisBC's power nominations under the new PPA were the quantities associated with the approved amounts of $51,426,000 and $54,482,000 (in 2012 and 2013 respectively) and the new PPA minimum take provisions applied.

<u>Response:</u>

This assumption does not reflect the full range of options available to FBC to manage the New PPA minimum take provisions. Based on the suggested assumptions, FBC power purchase actual expense would have increased by roughly $4.7 million in 2012 and $1.7 million in 2013 due to limitations in the ability to displace PPA power. Tables 1 and 2 below show the recast Tables C2-2 and C2-3.

However, this scenario would never have occurred. If the New PPA and all of its conditions were in place for 2012 and 2013, FBC would have forecast and planned for its actual use of PPA energy differently. The power nominations associated with the approved amounts of $51,426,000 and $54,482,000 (in 2012 and 2013 respectively) would have been less. FBC would have locked in market savings prior to the beginning of the year, consistent with what FBC has actually done for the first year of the New PPA, and what FBC has included in this Application. This would have resulted in a similar level of BC Hydro volume displacement as was actually achieved in 2012 and projected for 2013. It is not possible to state what cost impact, if any, there would have been but as discussed in the application at Section C, page 99, FBC has taken a more balanced approach for 2014 that reduces forecasted power purchase expense to more closely match expected PPA and market purchases.

This revised approach blends the ability to lock in savings through term purchases with real time opportunities and is seen as the preferred approach by FBC regardless of if the existing or New PPA is in effect. This new approach results in lower forecasted power purchase expenses and greater certainty that savings compared to the PPA rate will be achieved but at the expense of forgoing a certain amount of uncertain real time opportunity. FBC believes that if this approach had been employed for 2012 and 2013, costs would have been similar under either the existing or New PPA.

Table 1

		2012 Approved	2012 Actual	Difference
			($000s)	
1	Brilliant	35,601	35,591	(10)
2	BC Hydro	51,426	36,567	(14,859)
3	Independent Power Producers	155	180	25
4	Market and Contracted Purchases	2,645	8,461	5,816
5	Surplus Revenues	(427)	0	427
6	Special and Accounting Adjustments	(1)	(162)	(161)
7	Balancing Pool	0	(13)	(13)
8	TOTAL (before adjustments)	89,399	80,624	(8,775)
9	PPE Adjustment	(2,250)	0	2,250
10	**TOTAL**	87,149	80,624	(6,525)
11	Gross Load (GWh)	3,490	3,413	(77)

1 **Table 2**

		2013 Approved	2013 Forecast	Difference
		($000s)		
1	Brilliant	36,785	36,781	(4)
2	BC Hydro	54,482	38,288	(16,193)
3	Independent Power Producers	158	229	71
4	Market and Contracted Purchases	3,216	11,275	8,059
5	Surplus Revenues	(447)	(308)	139
6	Special and Accounting Adjustments	0	(738)	(738)
7	Balancing Pool	0	435	435
8	TOTAL (before adjustments)	94,192	85,962	(8,230)
9	PPE Adjustment	(2,250)	0	2,250
10	**TOTAL**	91,942	85,962	(5,980)
11	Gross Load (GWh)	3,534	3,461	(73)

2

3

21.0 Reference: Exhibit B-1, Section C2, Table C2-5, page 101

Total 2012 and 2013 Power Purchase Expense

"The 2014 Forecast is further compared to the 2013 year end forecast in Table C2-5. The 2013 year end forecast is based on actual results to April 30, 2013 and an updated forecast to the end of 2013."

21.1 Please provide the monthly forecast by month for 2013 from April to December, and provide a comparison against the actual values for May, June, July and if possible, August.

<u>Response:</u>

The requested comparison will be provided as part of the Evidentiary Update on October 18, 2013.

22.0 Reference: Exhibit B-1, Section C2, page 103

Market Price Forecast Methodology

"The forecast market prices are based on a combination of published and non-published sources, including a May 13, 2013 Argus Media Publication titled "Argus US Electricity" and consultations with market participants."

22.1 Please provide the referenced sources including summaries of the non-published sources.

Response:

Attachment 22.1 contains the May 13, 2013 Argus Media Publication titled "Argus US Electricity". The non-published sources are provided confidentially to FBC, and FBC was not able to obtain permission to provide the summaries of these sources. However, the Argus source is the main source used, and the non-published sources and consultations with market participants are used only to verify the forward prices from Argus.

23.0 Reference: Exhibit B-1, Section C2, pp. 103-104

Surplus Sales

"The Company expects to exercise this deal in July 2013 and July 2014, and currently forecasts 11 GWh in surplus sales for 2013, 22 GWh of surplus sales in 2014, compared to the 2012 actual amount of 0 GWh."

23.1 Please provide the actual surplus sales in July and August 2013.

Response:

July 2013 actual surplus sales were 12.240 GWh. There were no surplus sales in August 2013.

23.2 Please provide the comparison of forecast and actual market prices for 2012 and 2013, and the forecast for the surplus period in 2014.

Response:

The table below shows the forecast and actual market prices for FBC surplus sales in 2012, 2013 and 2014.

Year	RRA Approved/Forecast Surplus Sales Rate ($/MWh)	RRA Approved/Forecast Surplus Sales Rate Less $4/MWh Transmission Adder ($/MWh)	Actual Average July Hourly LLH Mid-C Market Price ($/MWh)	Variance
2012	$ 21.57	$ 17.57	$ 0.85	-$16.73
2013	$ 27.06	$ 23.06	$ 20.86	-$2.20
2014	$ 27.52	$ 23.52		

24.0 Reference: Exhibit B-1, Section C2, page 106

Summary of 2015 to 2018 Power Purchase Expense

"With the Waneta Expansion project forecast to come online in 2015, the Company will not have a capacity deficit, and will have surplus capacity compared to its forecast peak load requirements which it will sell in order to mitigate power purchase expense. The estimate of this mitigation is included in line 3 in Table C2-9 above."

24.1 Please provide a working spreadsheet model of the power purchase expense associated with the Waneta Expansion, fully describing and explaining all mitigating considerations and assumptions.

Response:

The details requested are of a confidential nature. Since the Commission has determined that the WAX CAPA will continue to be held confidential, FBC respectfully declines to provide this information.

25.0 Reference: Exhibit B-1, Section C3, Table C3-1, page 108

Other Income

25.1 Please extend Table C3-1 to include data back to 2007.

<u>Response:</u>

Please refer to the table below.

		Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Approved 2013	Projected 2013	Forecast 2014
						($000s)				
1	Apparatus and Facilities Rental	1,870	2,450	2,924	4,005	3,709	5,018	3,478	4,184	4,156
2	Contract Revenue	1,924	1,601	1,400	1,562	1,826	1,943	1,315	1,709	1,385
3	Miscellaneous Revenue	742	652	675	662	640	728	1,203	717	738
4	Transmission Access Revenue	-	-	-	-	1,151	1,454	1,071	1,247	1,224
5	Investment Income	968	333	188	224	180	104	98	90	78
6	Total	**5,504**	**5,035**	**5,187**	**6,453**	**7,506**	**9,247**	**7,165**	**7,947**	**7,582**

26.0 Reference: Exhibit B-1, Section C3, page 109

Transmission Access Revenue

26.1 Please provide the details associated with transmission access revenue.

Response:

The table below shows the annual forecast of transmission access revenue for FBC.

($000s)	2012 Actual	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Transmission Access Revenue	$ 1,454	$ 1,247	$ 1,224	$ 1,248	$ 1,273	$ 1,299	$ 1,325

27.0 Reference: Exhibit B-1, Section C4, Table C4-1, page 112

Historical O&M by Department

27.1 Please extend Table C4-1 to include data back to 2007.

Response:

Table C4-1 is extended to include actual data back to 2007.

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Generation	$ 1,908	1,894	$ 2,152	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,950	14,924	15,057	14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 6,154	6,272	5,835	5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,003	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	$ 2,865	2,834	2,938	2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 973	1,184	1,143	1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 1,220	1,651	1,028	993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 2,718	2,834	3,537	3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 645	616	645	727	867	894	925	953	953
Finance & Regulatory	$ 3,835	3,631	3,624	3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,701	1,540	1,558	1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,149	2,006	2,066	2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 2,878	3,716	4,545	3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-	-	-	-	-	-	-
Total O&M	**$ 43,001**	**$ 44,725**	**$ 46,017**	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**

28.0 Reference: Exhibit B-1, Section C4, Table C4-4, page 123

Generation O&M

28.1 Please extend Table C4-4 to include data back to 2007.

Response:

Table C4-4 has been extended to include data back to 2007.

Generation O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,454	$ 1,453	$ 1,655	$ 1,600	$ 1,703	$ 1,854	$ 1,887	$ 1,916	$ 2,357
Non-Labour	453	441	497	617	696	477	605	640	689
Total O&M	**$ 1,908**	**$ 1,894**	**$ 2,152**	**$ 2,217**	**$ 2,399**	**$ 2,331**	**$ 2,492**	**$ 2,556**	**$ 3,046**

29.0 Reference: Exhibit B-1, Section C4, Table C4-6, page 125

Unit maintenance

"The actual schedule will be guided by condition, risk and operational priority. The Generation department estimates the annual cost of Major Unit Inspections at $350,000."

29.1 For each Upgrade and Life Extension project shown in Table C4-6, please provide the discussion from the CPCN Application or related regulatory document that described the effect of the project on future maintenance costs.

Response:

Although no discussion of the impact of the Upgrade and Life Extension projects on maintenance costs is provided in the respective applications for the various ULEs (not all ULE projects were the subject of a CPCN application), the completion of the ULE projects each contributed to a savings of approximately $100,000 in the year of the life extension and the year following related to avoided maintenance on the upgraded unit.

29.2 Please show where past Generation O&M budgets have been decreased to reflect the foregone maintenance because of the ULE projects, or were these decreased maintenance costs captured as "efficiency gains" in past PBR cycles?

Response:

As noted on page 125 of the Submission, "*since the initiation of the ULE program no major overhauls were completed on any of the units*." Therefore, the annual O&M savings would be mainly the overhaul costs that were deferred and these efficiency gains are reflected in the annual O&M costs. However, actual O&M costs would have increased due to other factors negating the efficiency gains. For example, in order to comply with new Work Safe BC and environmental regulations, mandatory training programs for employees increased to approximately 30 programs over the last 7 years. Along with the new training requirements, new safety regulations mandated different work practices that added man hours and expenses for many tasks. Also, environmental monitoring and testing has become more important and the frequency of testing has increased again adding costs. So overall, as shown in Table C4-4, the Generation Department expenditures have remained relatively constant over the past few years despite factors that would ordinarily have caused an increase.

30.0 Reference: Exhibit B-1, Section C4, Table C4-7, page 138

Operations O&M

"The table above shows the increase in 2011 resulting from the Commission's decision on the Company's 2011 Capital Expenditure Program (Order G-195-10) directing that certain capital expenditures (totalling $3.78 million) were more appropriately classified as operating expenses. This reclassification affected both labour and non-labour resources."

30.1 Please extend Table C4-7 to include data back to 2007.

Response:

Table C4-7 has been extended to include data back to 2007.

Operations O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 8,373	$ 8,579	$ 8,896	$ 8,668	$ 9,532	$ 10,060	$ 10,812	$ 10,794	$ 11,564
Non-Labour	6,576	6,345	6,161	6,223	9,072	9,670	10,004	10,144	10,196
Total O&M	**$ 14,950**	**$ 14,924**	**$ 15,057**	**$ 14,892**	**$ 18,604**	**$ 19,730**	**$ 20,816**	**$ 20,938**	**$ 21,760**

30.2 Please identify where in Order G-195-10 it was permitted for the re-classified capital expenditures to increase the total overall operations expenditures rather than being absorbed within the originally applied for operations budget.

Response:

Order G-195-10 disallowed the referenced expenditures from being included as capital expenditures, and instead directed FBC to address the expenditures as part of its ordinary operating and maintenance expense budget. The reclassification of these expenditures into O&M was reflected in the financial schedules submitted by FBC on December 20, 2010, which were approved by the Commission for the setting of 2011 rates. As well, these expenditures were included as operating and maintenance expense in the 2012-13 RRA, and subsequently approved by Order G-110-12.

30.3 Please provide a detailed description of the re-classified capital expenditures, and please identify whether similar expenditures occurred prior to 2011. If similar expenditures did occur in past periods, please explain how the costs were recovered.

Response:

The reclassified expenditures are related to the following:

- Transmission Pine Beetle Kill Hazard Tree Removal;
- Distribution Pine Beetle Kill Hazard Tree Removal; and
- Hot Tap Connector Replacement.

With respect to the Transmission and Distribution Pine Beetle Kill Hazard Tree Removal, these expenditures are required to remove hazard trees kills by the Mountain Pine Beetle that have a high probability of falling directly onto energized distribution lines. FBC began incurring costs related to this program in 2008, and was directed by Order G-147-07 regarding the 2008 Revenue Requirements to record the 2008 removal costs in a rate-base deferral account to be amortized over 10 years. Order G-11-09 regarding the 2009/2010 Capital Plan approved the capital expenditures related to pine beetle kill hazard tree removal. Order G-195-10 regarding the 2011 Capital Plan directed FBC to begin treating these expenditures as routine operating and ordinary maintenance expense.

With respect to the Hot Tap Connector Replacement, these expenditures are required to address employee and public safety, and reliability issues associated with conductor burn off caused by deteriorated hot tap connectors. This project began in 2009, and involves the replacement of existing hot tap connectors with device called a stirrup to provide a location to which the hot tap connector can be safely attached. Order G-11-09 regarding the 2009/2010 Capital Plan approved the capital expenditures related to this program. Order G-195-10 regarding the 2011 Capital Plan directed FBC to begin treating these expenditures as routine operating and ordinary maintenance expense.

31.0 Reference: Exhibit B-1, Section C4, Table C4-9, page 132

Customer Service

31.1 Please extend Table C4-9 to include data back to 2007.

Response:

The table below extends Table C4-9 to include data back to 2007.

Customer Service O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 4,184	$ 4,046	$ 4,152	$ 4,329	$ 4,725	$ 4,716	$ 4,830	$ 4,669	$ 5,002
Non-Labour	1,970	2,226	1,683	1,646	1,673	2,050	2,711	2,841	2,856
Total O&M	**$ 6,154**	**$ 6,272**	**$ 5,835**	**$ 5,975**	**$ 6,398**	**$ 6,766**	**$ 7,541**	**$ 7,510**	**$ 7,858**

32.0 Reference: Exhibit B-1, Section C4, Table C4-13, page 138

Energy Supply O&M

32.1 Please extend Table C4-13 to include data back to 2007.

Response:

Table C4-13 has been extended to include data back to 2007.

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ 514	$ 583	$ 629	$ 631	$ 709	$ 772	$ 732	$ 784
Non-Labour	-	32	156	198	262	277	352	392	394
Total O&M	**$ -**	**$ 546**	**$ 739**	**$ 827**	**$ 893**	**$ 986**	**$ 1,124**	**$ 1,124**	**$ 1,178**

33.0 Reference: Exhibit B-1, Section C4, Tables C4-17 and C4-18, page 132

Engineering Services and Mandatory Reliability Standards

33.1 Please extend Table C4-17 to include data back to 2007.

Response:

Table C4-17 has been extended to include data back to 2007.

Engineering Services and Project Management O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 651	$ 823	$ 823	$ 928	$ 1,789	$ 1,951	$ 2,127	$ 1,974	$ 2,964
Non-Labour	322	361	320	314	574	664	664	848	903
Total O&M	**$ 973**	**$ 1,184**	**$ 1,143**	**$ 1,242**	**$ 2,363**	**$ 2,615**	**$ 2,791**	**$ 2,822**	**$ 3,867**

33.2 Please provide FortisBC's response original BCTC inquiry regarding the expected incremental costs associated with Mandatory Reliability Standards.

Response:

FBC's input is part of the BCTC Assessment Report dated March 27, 2009. Due to the size of the report (over 1400 pages / 22 Mbytes), FBC provides the following link to the BCUC MRS website where this assessment report can be found: http://www.bcuc.com/mrs.aspx

Below is a table summarizing the estimates at that time.

BCTC		BC Hydro		FortisBC	
One-Time	Ongoing	One-Time	Ongoing	One-Time	Ongoing
$ 301,200	$ 420,000	$ 5,399,500	$ 938,500	$ 510,000	$ 625,000

33.3 Please provide a detailed reconciliation of the actual 2011 and 2012 Mandatory Reliability Standards expenditures, including number of personnel, travel expenses, external consultant costs, etc.

Response:

Please see the table provided below:

	2011 Actual	2012 Actual
	($000s)	
Labour	$ 856	$ 1,328
Consultant/Contractor	$ 82	$ 77
General Operating Expenses	$ 78	$ 94
Totals	**$ 1,016**	**$ 1,499**

Note: 2012 actual includes $0.3 million recorded in the deferral account approved by Order G-23-13.

Incremental costs to the organization associated with MRS are recorded in the MRS budget to properly track the increased effort since implementation.

Labour costs include incremental MRS related costs from other departments. FTEs working on MRS tasks have varying degrees of involvement. The compliance effort in 2011 for Operating was approximately 12,000 operating hours and in 2012 was approximately 15,000 operating hours.

Consultant/Contractor costs include those to provide support in specific areas of expertise required by FortisBC to maintain compliance. They include specialized support that may be required for any of the standards.

General Operating Expenses include costs for routine expenses for the department (telephones, travel, participation in user groups, etc.), training expenses and incremental operating expenses from other departments.

33.4 Please provide the results of FortisBC's first BCUC/WECC audit in July of 2012.

Response:

The results of the 2012 BCUC/WECC audit are provided below.

	No Finding	Not Applicable	Open Action	Possible Violation	Total
Number of Requirements	78	5	25	1	109

No Finding (NF): The audit team did not discover areas of non-compliance based on the evidence presented by the Registered Entity and reviewed by the audit team.

Not Applicable (NA):

- The Requirement does not apply to the Registered Entity based on functions for which the entity is registered.
- The Requirement applies to the Registered Entity based on their functional registration but the entity does not possess the system(s) referenced in the Requirement. Examples could be that the entity does not possess black start units, SPS, or UVLS.

Open Action (OA): At the time of the audit, the Registered Entity had an open action item regarding a Requirement. Such items may include, but are not limited to open mitigation plans, self-reports, or settlement agreements.

Possible Violation (PV): The audit team discovered areas of possible non-compliance based on the evidence presented by the Registered Entity and reviewed by the audit team.

34.0 Reference: Exhibit B-1, Section C4, Table C4-21, page 149

Operations Support O&M

34.1 Please extend Table C4-21 to include data back to 2007.

Response:

The table below extends Table C4-21 to include data back to 2007.

Operations Support O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 3,311	$ 3,592	$ 3,212	$ 3,475	$ 3,510	$ 3,354	$ 3,510	$ 3,425	$ 3,669
Non-Labour	4,369	3,726	3,557	3,152	2,992	2,754	3,829	3,027	3,042
Recoveries	(6,459)	(5,667)	(5,741)	(5,633)	(5,186)	(4,868)	(6,087)	(5,247)	(5,453)
Total O&M	**$ 1,220**	**$ 1,651**	**$ 1,028**	**$ 993**	**$ 1,315**	**$ 1,240**	**$ 1,252**	**$ 1,205**	**$ 1,258**

35.0 Reference: Exhibit B-1, Section C4, Table C4-25, page 156

Environment, Health and Safety O&M

35.1 Please extend Table C4-25 to include data back to 2007.

<u>Response:</u>

Table C4-25 has been extended to include data back to 2007.

EH&S O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 426	$ 458	$ 480	$ 586	$ 689	$ 714	$ 760	$ 830	$ 889
Non-Labour	219	157	164	141	178	180	193	123	124
Total O&M	**$ 645**	**$ 616**	**$ 645**	**$ 727**	**$ 867**	**$ 894**	**$ 953**	**$ 953**	**$ 1,013**

36.0 Reference: Exhibit B-1, Section C5, Tables C5-1 and C5-2

Historical FBC Capital Expenditures

36.1 Please extend Tables C5-1 and C5-2 to include data back to 2007 (for both stand-alone and ongoing projects, as applicable), showing both approved and actual amounts.

<u>Response:</u>

Table C5-1 has been extended back to 2007 with “Actual” and “Approved” values in the table below:

	2007 Actual	2007 Approved	2008 Actual	2008 Approved	2009 Actual	2009 Approved	2010 Actual	2010 Approved	2011 Actual	2011 Approved	2012 Actual	2012 Approved	2013 Approved	2013 Projection
Generation Base Captal	4,352	4,480	4,660	5,449	6,528	5,890	3,589	3,632	2,128	3,248	4,386	4,039	2,363	2,823
Generation Major Projects	15,428	16,319	10,695	12,704	11,883	14,487	13,966	15,825	13,828	13,859	2,599	2,935	-	425
Total Generation Capital	**19,781**	**20,798**	**15,355**	**18,153**	**18,411**	**20,378**	**17,555**	**19,457**	**15,956**	**17,108**	**6,985**	**6,973**	**2,363**	**3,248**
Transmission-Dist. - Stn. Base Capital	52,105	50,082	44,619	36,412	38,525	50,420	42,999	45,734	34,719	36,606	29,731	45,130	36,591	52,031
Transmission-Dist. - Stn. Major Projects	43,470	34,457	31,701	50,644	33,890	36,881	61,489	79,442	13,389	13,673	6,003	10,892	11,886	45,230
Total Transmission-Dist. - Stn. Capital	**95,575**	**84,539**	**76,321**	**87,056**	**72,416**	**87,301**	**104,488**	**125,176**	**48,109**	**50,280**	**35,734**	**56,022**	**48,477**	**97,261**
Other Base Captal	13,834	14,497	7,912	7,679	8,342	8,740	8,448	8,462	11,605	9,179	7,974	10,689	16,146	10,755
Other Major Projects	-	-	-	-	-	-	-	-	540	2,110	1,700	9,367	34,985	21,929
Total Other Capital	**13,834**	**14,497**	**7,912**	**7,679**	**8,342**	**8,740**	**8,448**	**8,462**	**12,145**	**11,290**	**9,674**	**20,056**	**51,130**	**32,684**
Total Gross Capital Expenditure	**129,189**	**119,834**	**99,587**	**112,888**	**99,169**	**116,419**	**130,491**	**153,095**	**76,209**	**78,677**	**52,393**	**83,052**	**101,970**	**133,193**

Note: Minor differences due to rounding.

The extension for Table C5-2 with "Approved" & "Actual" values, extended back to 2007 have been provided in the tables below.

Please note that for the purpose of simplicity the Cost of Removals and loadings have been adjusted at the bottom of the tables.

Year 2007		
Hydraulic Production	**Decision**	**Actual**
Upper Bonnington Old Unit Repowering	2,404	1,876
South Slocan Unit 1 Upgrade & Life Extension	8,747	3,160
Lower Bonnington Unit 1 Upgrade/Life Extension		118
Lower Bonnington Unit 2 Headgate Rebuild	-	233
Lower Bonnington Unit 3 Upgrade & Life Extension	7,377	7,980
Lower Bonnington Unit 3 Headgate Rebuild	68	167
Corra Linn Unit 1 Life Extension		102
South Slocan Completion		694
South Slocan Unit 2 Rebuild & Life Extension	-	1,493
South Slocan Poleyard Contaminated Site	325	497
South Slocan Unit 1 & 3 Headgate Rebuild	513	-
South Slocan Unit 3 Headgate Rebuild	-	449
South Slocan Unit 3 Life Extension	870	3,164
Generating Plants Area Lighting	226	214
Generating Plants Upgrade Station Service Supply	255	672
Lower Bonnington Generator & Plant Cooling System	46	-
Generation Sustaining & Misc upgrades	828	(416)
	21,659	**20,404**
Transmission Plant		
Kootenay 230kV Transmission	-	(3,348)
South Okanagan Supply Reinforcement	-	873
Okanagan Transmission Reinforcement	2,997	3,838
Kelowna Area Upgrade	-	423
Big White Transmission and Substation	9,969	9,666
Ellison Distribution Source	13,319	1,744
Black Mountain Distribution Source	497	476
Fault Level Reduction	-	350
Naramata Rehabilitation	1,959	703
New East Osoyoos Source - Nk'Mip Sub	12,489	15,251
Kettle Valley Distribution	9,491	18,378
Ymir Upgrade	-	562
Lambert Transformer 2	2,797	5,290
Princeton Transformer Replacement	-	1,511
Transmission Line Sustaining	3,671	2,736
Station Sustaining	3,808	4,248
Ootischenia Substation	-	492
Coffee Creek Capacitor	245	
Transformers and Capitalized Inventory	-	2,468
Crawford Bay Capacitor	1,714	2,182
Glenmore Substation New Feeder	392	478
Westbench Regulator Bank	294	272
Hedley Stepup Transformer	391	470
Duck Lake Regulator Bank	294	
18 L Breaker @ Waneta		3
Kaslo Capacitor	78	
	64,405	**69,068**
Distribution Plant		
Customer New Connects	14,490	21,918
Distribution Sustaining	8,016	10,417
Distribution Growth Greater than 1 Million	1,371	1,504
Distribution Growth Less than 1 Million	3,129	4,420
T&D other		227
	27,006	**38,486**
General Plant:		
Communication and Automation	3,458	162
Protection and Communications Rehabilitation	1,482	1,022
Vehicles	3,400	4,431
Metering	64	542
Telecommunications	175	221
Information Systems	5,640	6,655
Buildings	5,410	1,565
Furniture & Fixtures	212	248
Tools & Equipment	749	936
	20,590	**15,782**
TOTAL Gross Expenditures	**133,660**	**143,742**
Add Cost of Removals	2,999	2,999
Less Loadings	(16,825)	(17,552)
TOTAL Gross Expenditures Unloaded	**119,834**	**129,189**

Year 2008		
Hydraulic Production	**Decision**	**Actual**
Lower Bonnington Unit 3 Upgrade & Life Extension	-	430
Upper Bonnington Old Unit Repowering Phase 1	2,266	1,872
South Slocan Unit 1 SS Life Extension & Turbine	3,149	2,433
South Slocan Poleyard Contaminated Site	-	115
South Slocan Unit 1 Headgate Rebuild	61	1
South Slocan Unit 3 Life Extension	9,322	7,714
South Slocan Unit 3 Headgate Rebuild	580	460
South Slocan Unit 2 Bottom Ring Rebuild & Life Extens	-	53
South Slocan Completion	310	574
South Slocan H/G Hoist Contr, Wire Rope	669	181
Corra Linn Unit 1 Life Extension	881	650
All Plants Upgrade Station Service Supply	473	498
All Plants Spare Unit Transformer	-	43
Generating Sustaining & Misc Upgrades	1,368	1,170
	19,079	**16,195**
Transmission Plant		
Kootenay 230kV Transmission	-	64
South Okanagan Supply Reinforcement	-	(106)
Okanagan Transmission Reinforcement	13,631	3,418
Big White Transmission and Substation	7,183	7,380
Ellison Distribution Source	12,990	7,810
Black Mountain Distribution Source	9,960	6,811
Fault Level Reduction	-	58
Naramata Rehabilitation	1,815	541
New East Osoyoos Source - Nk'Mip Sub	-	144
Kettle Valley Distribution	2,605	4,802
Princeton Transformer Replacement	-	8
Transmission Line Sustaining	3,528	3,038
Station Sustaining	2,518	5,246
Ootischenia Sub	5,340	5,492
Benvoulin Substation	4,812	-
Capitalized Inventory	-	349
Crawford Bay Capacitor	-	9
Glenmore Substation New Feeder	-	93
Westbench Regulator Bank	-	2
Hedley Stepup Transformer	-	6
18 L Breaker @ Waneta	1,800	1,797
	66,182	**46,961**
Distribution Plant		
Customer New Connects	15,954	24,434
Distribution Sustaining	9,231	8,474
Distribution Growth Greater than 1 Million	-	71
Distribution Growth Less than 1 Million	3,247	3,513
	28,432	**36,492**
General Plant		
Communication and Automation	1,456	1,108
Protection and Communications Rehabilitation	1,088	1,764
Vehicles	2,461	1,628
Metering	136	278
Telecommunications	175	258
Information Systems	3,776	4,543
Buildings	1,312	1,527
Furniture & Fixtures	187	237
Tools & Equipment	650	587
	11,241	**11,930**
TOTAL Gross Expenditures	**124,934**	**111,579**
Add Cost of Removals	5,025	5,025
Less Loadings	(17,071)	(17,015)
TOTAL Gross Expenditures Unloaded	**112,888**	**99,589**

Year 2009		
Hydraulic Production:	**Decision**	**Actual**
Upper Bonnington Old Unit Repowering Phase 1	1,094	1,053
South Slocan U1 SS Life Extention & Turbine	7,832	8,135
South Slocan U1 Headgate Rebuild	577	680
Corra Linn U1 Life Extension	4,487	2,611
South Slocan U3 Life Extension	2,051	1,949
South Slocan Poleyard Contaminated Site	-	45
South Slocan H/G Hoist Contr, Wire Rope	434	764
All Plants Upgrade Station Service Supply	484	646
All Plants Spare Unit Transformer	1,380	1,408
Generation Sustaining & Miscellaneous Upgrades	1,778	1,056
South Slocan Completion	940	902
All Plants Lighting Upgrade	478	387
Corra Linn U2 ULE	-	33
	21,535	**19,669**
Transmission Plant:		
Okanagan Transmission Reinforcement	30,341	21,503
Benvoulin Substation Capacity Increase	4,382	4,110
Kelowna Distribution Capacity Requirements	518	271
Big White Transmission and Substation	-	110
Ellison Distribution Source	1,734	5,608
Black Mountain Distribution Source	4,517	7,196
Naramata Rehabilitation	3,962	3,654
Tarrys Capacity Increase	403	265
Kettle Valley Distribution Source	-	473
Recreation Capacity Increase	178	179
30 Line Conversion	4,500	866
Transmission Line Sustaining	4,265	3,424
Station Sustaining	4,671	3,476
Ootischenia	389	142
Capitalized Inventory	-	(1,301)
Duck Lake Expansion (BC Hydro Woods Lake Project)	-	10
	59,860	**49,985**
Distribution Plant:		
Customer New Connections	23,564	15,833
Distribution Sustaining	10,638	12,517
Distribution Growth	1,762	2,449
	35,964	**30,799**
General Plant:		
Distribution Automation	1,338	1,784
Protection & Communication Rehabilitation	747	765
Vehicles	2,000	2,342
Metering	526	431
Information Systems	5,167	4,768
Tlecommunications	105	90
Buildings	1,305	1,270
Furniture & Fixtures	347	294
Tools & Equipment	572	525
	12,107	**12,269**
TOTAL Gross Expenditures	**129,465**	**112,723**
Add Cost of Removals	4,502	4,502
Less Loadings	(17,549)	(18,057)
TOTAL Gross Expenditures Unloaded	**116,418**	**99,168**

Note: Minor differences due to rounding.

Year 2010

Hydraulic Production:	Decision	Actual
All Plants Spare Unit Transformer	-	107
LBO & UBO Comm. Network Comp.	297	257
All Plants Fire Safety Upgrade Ph.1	-	38
SLC U1 Life Extension (replace turbine)	3,261	1,591
SLC U1 Head Gate Rebuild	279	84
All Plants Public Safety & Security Ph.1	52	90
P3 Poleyard Contaminated Site	-	(23)
P1 P4 Capital Planning 2008 Project	-	(1)
UBO Old Unit Repowering (Ph.1)	651	318
All Plants Upgrade Station Service Supply	1,191	1,228
SLC H/G Hoist, Control, Wire Rope Upgrade	-	145
SLC Plant Completion	1,598	649
COR U1 Life Extension (replace Turbine)	8,476	9,647
COR U2 Life Extension (replace Turbine)	2,987	3,505
SLC Dam Rehabilitation Study	-	28
UBO Extension Trash Rack Gantry Replacement	417	204
All Plants Spare Exciter Transformer	116	105
LBO Intake Area Upgrade Ph.2	102	31
SLC Domestic Water Supply Ph.3	50	45.91926
All Plants 2009 Pump Upgrades	-	79
All Plants Lighting Upgrade	338	256
P2 Tailrace Gate Corrosion Control	139	131
Queen's Bay Level Gauge Building Ph.1	-	5
2011 Projects	-	11
SLC Tailrace Gate Corrosion Control	114	-
	20,068	**18,531**
Transmission Plant:		
Ellison Distribution Source	-	102
Black Mountain Distribution Source	-	(6)
Okanagan Transmission Reinforcement	74,378	55,715
Benvoulin Distribution Source	13,301	11,435
Naramata Rehab	-	(506)
Huth Split Bus	413	241
Capitalized Inventory	-	(580)
Recreation Capacity Increase Stage 1,2,3	3,401	3,447
Tarry's Capacity Increase	-	51
Kelowna Distribution Capacity Requirements	517	493
30L Conversion Slocan / Coffee Creek S/Stns	-	3,689
Transmission Line Sustaining	4,699	3,428
Station Sustaining	4,920	3,140
2011 Projects	-	10
Duck Lake Expansion (BC Hydro Woods Lake Project)	-	(10)
	101,629	**80,647**
Distribution Plant:		
Customer New Connections	19,070.0	15,926.9
Distribution Sustaining	11,126	12,605
Distribution Growth	4,274	2,652
2011 Projects	-	108
Subtotal Distribution Plant	**34,470**	**31,291**
General Plant:		
Distribution Automation	1,438	1,488
Protection & Communication Upgrades	619	680
Mandatory Reliability Compliance (MRC)	-	1,811
Vehicles	2,000	1,318
Metering	559	187
Information Systems	4,499	4,309
Telecommunications	106	52
Buildings	1,062	948
Furniture & Fixtures	393	268
Tools & Equipment	574	507
	11,250	**11,568**
TOTAL Gross Expenditures	**167,416**	**142,038**
Add Cost of Removals	4,941	7,872
Less Loadings	(19,262)	(19,419)
TOTAL Gross Expenditures Unloaded	**153,095**	**130,491**

Year 2011

Hydraulic Production:	Decision	Actual
2011 Provincial Sales Tax (PST) Refund	-	(145)
South Slocan Plant Automation	251	208
South Slocan Fire Panel	275	269
Upper Bonnington Spillgate Rebuild / Upgrade	630	40
Lower Bonnington Power House Windows	362	244
All Plants Minor Sustaining Projects	633	469
Lower Bonnington & Upper Bonnington Communicatic	-	48
South Slocan Unit 1 Life Extension (replace turbine)	42	44
All Plants Upgrade Station Service Supply	1,352	927
South Slocan Head Gate Hoist, Control, Wire Rope Upg	-	37
Corra Linn Unit 1 Life Extension (replace Turbine)	2,507	2,990
Corra Linn Unit 2 Life Extension (replace Turbine)	12,781	12,090
Upper Bonnington Extension Trash Rack Gantry Replac	-	165
South Slocan Domestic Water Supply Ph.3	-	61
Lower Bonnington & Upper Bonnington Plant Totalize	89	93
Queen's Bay Level Gauge Building Ph.1	-	3
	18,924	**17,543**
Transmission Plant:		
Ellison Sexsmith Transmission Tie	693	638
Okanagan Transmission Reinforcement	16,056	12,821
Benvoulin Distribution Source	-	993
Huth Split Bus	4,860	3,612
Capitalized Inventory & Transformers	-	727
Recreation Capacity Increase Stage 1,2,3	-	(21)
30L Conversion Slocan / Coffee Creek S/Stns	-	314
Transmission Line Sustaining	2,455	2,477
Station Sustaining	2,764	5,223
	26,828	**26,786**
Distribution Plant:		
Gross New Connects System Wide	21,584.4	16,408.8
Distribution Unplanned Growth Projects	986	981
Small Growth Projects	751	685
Distribution Sustaining	8,227	8,359
Subtotal Distribution Plant	**31,549**	**26,434**
General Plant:		
Distribution Automation	1,602	2,162
Protection, Harmonic Remediation,Communication & R	1,613	1,975
Mandatory Reliability Compliance (MRC)	615	872
Vehicles	2,072	2,664
Metering	221	316
Information Systems	4,682	4,829
Telecommunications	371	315
Buildings	1,288	1,287
Kootenay Long Term Facility Strategy	503	433
Okanagan Long Term Solution	507	190
PCB Environmental Compliance	1,926	1,718
Furniture & Fixtures	182	230
Tools & Equipment	623	609
	16,206	**17,602**
TOTAL Gross Expenditures	**93,507**	**88,365**
Add Cost of Removals	2,781	5,267
Less Loadings	(17,610)	(17,423)
TOTAL Gross Expenditures Unloaded	**78,678**	**76,209**

Year 2012

Hydraulic Production	Decision	Actual
South Slocan Plant Automation		68
All Plants Concrete & Structural Rehabilitation	340	269
Corra Linn Unit 3 Completion	274	281
Upper Bonnington Spillgate Rebuild / Upgrade	1,065	1,614
Lower Bonnington Power House Windows	366	463
All Plants Minor Sustaining Projects	946	773
Upper Bonnington Old Plant Various Unit Upgrades	507	217
Lower Bonnington, Upper Bonnington & Corra Linn Fi	250	280
All Plants Upgrade Station Service Supply	674	1,217
Corra Linn Unit 1 Life Extension (replace Turbine)		46
Corra Linn Unit 2 Life Extension (replace Turbine)	3,438	2,600
South Slocan Fire Panel		24
Lower Bonnington & Upper Bonnington Plant Totalize	90	32
Queen's Bay Level Gauge Building Ph.1		3
	7,950	**7,886**
Transmission Plant		
Ellison Sexsmith Transmission Tie	6,538	125
Okanagan Transmission Reinforcement	2,219	3,825
Huth Split Bus	-	1,266
Capitalized Inventory	-	247
Backbone Transport Technology Migration	14	28
Transmission Line Urgent Repairs	446	490
Transmission Right of Way Acquisition / Easements	407	439
6 Line / 26 Line River Crossing Reconfiguration	939	498
Transmission Line Condition Assessment	498	461
PCB Environmental Compliance	10,912	4,167
Transmission Line Rehabilitation	3,006	2,469
21-24 Lines Rebuild (Generation Plants)	2,147	714
27 Line Rebuild (Corra Linn - Salmo)	1,074	959
Station Assessment / Minor Planned Projects	1,342	1,337
SCADA Systems Sustainment	718	767
Station Unforseen /Urgent Repairs	712	568
Add Arc Flash Detection to Legacy Metal Clad Switch	439	361
2013 Transmission Projects-1 (20 Line Rebuid)		9
2013 Transmission Projects-2 (Transmission Line Rehab)		32
Passmore - 19L Breaker		165
	31,409	**18,925**
Distribution Plant		
New Connects System Wide	22,276	15,665
Distribution Small Growth Projects	1,075	639
Distribution Unplanned Growth Projects	839	777
Distribution Condition Assessment	891	847
Distribution Rehabilitation	3,452	2,882
Distribution Line Rebuilds	1,393	1,051
Small Planned Capital	439	600
Distribution Forced Upgrades	1,828	1,151
Distribution Urgent Repairs	2,115	2,313
41 Line Salvage & Distribution Underbuild Rehabilitatic	805	69
	35,112	**25,994**
General Plant		
Distribution Substation Automation	-	37
Protection Upgrades (F.A. Lee Stn. to Vernon 230kV Pr	- -	403
Communication Upgrades	403	388
Mandatory Reliability Compliance (MRC)	-	112
Buildings	1,368	1,536
Kootenay Long Term Facility Strategy (Kootenay Ops	6,296	360
Okanagan Long Term Solution	69	48
Central Warehousing	1,764	1,634
Furniture & Fixtures	122	113
Fleet	2,432	1,959
Telecommunications	122	99
Infrastructure Sustainment	1,116	1,219
Desktop Infrastructure Sustainment	1,120	1,223
Applications Enhancements	1,240	1,267
Application Sustainment	1,184	1,192
Power Sense DSM Reporting Software	1,020	115
Meter	405	446
Advanced Metering Infrastruture	4,501	-
Tools	530	531
	23,694	**11,876**
TOTAL Gross Expenditures	**98,165**	**64,680**
Add Cost of Removals	4,260	3,710
Less Loadings	(19,373)	(15,999)
TOTAL Gross Expenditures Unloaded	**83,052**	**52,391**

Note: Minor differences due to rounding.

37.0 Reference: Exhibit B-1, Section C5, page 179

Adjustments for return to PST and pension adjustment

37.1 Please describe the changes that were made to FortisBC budgets and approved amounts when the original transition from the PST to HST occurred in 2010.

Response:

The Company did not incorporate the impacts of transition to HST in the 2010 Revenue Requirements Application because the HST restrictions and transitional rules had not yet been finalized at the time of the Application.

The Company assessed the impact of the new HST rules on O&M for the last six months of 2010 and for the full 2011 year and included an estimate of approximately $0.1 million in 2010 O&M savings as a Flow-through Adjustment to 2011 rates. In addition, the Company had estimated approximately $0.2 million savings related to HST impacts in 2011 O&M.

The Company also assessed the impact of the new HST rules on the 2010 capital expenditures expected to be incurred between July 1, 2010 and December 31, 2010 and the variance was considered to be immaterial.

In addition, the Company incurred costs to implement the HST, including information system changes of approximately $0.2 million that was amortized in 2011.

37.2 Please explain the pension addition in 2013 shown in Table C5-2, why it is necessary, how it arose, and where it has been approved.

Response:

Since the determination of 2013 Base Capital in Table C5-2 starts with approved 2013 capital expenditures, which included pension/OPEB costs originally estimated in 2011 by the Company's third party external actuary, it is necessary to increase the 2013 Base Capital by $1,723 thousand to reflect the current cost of pensions and OPEBs in 2013. The rebasing of 2013 capital to adjust for the increased cost in pension and OPEBs in 2013 is necessary as pension and OPEB expenses are included in the forecast labour inflation and benefit loads that are applied to the forecast labour force. Increases in labour and benefits are allocated between O&M and capital based on the chargeable hours forecast against O&M and capital activities, of which an incremental $1,723 thousand is estimated as attributable to base capital for 2013.

The increase in pension and OPEB arose as explained in C4.3.3.4 - Labour and Benefits Inflation on page 117 of the PBR Application which states that "Pension and OPEB expense has been and will continue to be a significant challenge in managing increases in costs for FBC. For

2013, the actuarial estimate that was recently completed is approximately 70 percent higher than the actuarial estimate that was completed in 2011 to establish the 2012-2013 RRA forecasts and approved amounts. This increase is primarily due to the low interest rate environment and poorer than expected returns on pension plan assets. The difference between the actual and approved 2013 pension and OPEB expense has been accumulated in a deferral account which was approved pursuant to Order G-110-12."

In previous revenue requirement applications, FBC has been approved to recover all costs related to pensions and OPEBs due to their uncontrollable nature as described further in the response to BCUC IR 100.1

Please also refer to the responses to BCUC IRs 1.212.1 and 1.212.1.1 that provide further explanation on the pension/OPEB adjustment.

38.0 Reference: Exhibit B-1, Section C5, pp. 189-207

Generation, Station, Transmission Lines, Distribution Lines and Telecom, SCADA & P&C Sustainment Capital

38.1 For each project described in Sections 5.4.2 through 5.4.6, please provide a table showing annual amounts for approved and actual expenditures since inception (or since 2007 for on going programs) and forecast to completion, and provide a comparison, if applicable, to similar projects proposed in FortisBC's 2012 Long Term Capital Plan, filed as part of the 2012 Integrated System Plan.

<u>Response:</u>

The requested table is provided below.

	2007		2008		2009		2010		2011		2012		2013		2014	2015	2016	2017	2018
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	($000s)																		
Generation																			
Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels	-	-	-	-	-	-	-	-	-	-	250	280	231	312	-	-	-	438	-
P4 Spillway and Spillgate CPCN Engineering	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	540	487	-	-
All Plants Safety and Security	-	-	-	-	-	-	-	-	-	-	-	-	179	214	-	-	-	-	94
All Plants Fire Safety	-	-	-	-	-	-	-	-	-	-	-	-	-	-	458	401	405	527	-
All Plants Concrete and Structural Rehabilitation	-	-	-	-	-	-	-	-	-	-	340	269	408	384	432	572	531	517	524
Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	-	-	-	-	-	-	-	-	-	-	-	131	215	164	-	-	184	-
Dam Safety Instrumentation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	286
All Plants Minor Sustainment Capital	828	(416)	1,368	1,170	1,778	1,056	-	-	633	469	946	773	925	1,074	1,679	1,247	1,340	1,194	1,639
Station Sustainment															-	-	-	-	-
Environmental Compliance (PCB Mitigation)	-	-	-	-	-	-	-	-	1,926	1,718	10,912	4,167	11,408	12,781	5,259	-	-	-	-
Station Urgent Repairs	99	176	400	596	473	774	448	537	594	702	712	568	722	734	488	523	508	559	538
Station Assessment/Minor Planned Projects	-	68	1,186	1,505	236	281	-	-	623	660	1,342	1,337	910	910	1,109	1,131	1,154	1,177	1,200
Ground Grid Upgrades	-	-	299	104	572	360	-	147	-	-	-	-	-	-	645	-	575	-	598
Osoyoos 63 kV Breaker Additions (2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	137	645	-	-	-
DG Bell 138 kV Breaker and Voltage Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	738	-
Bulk Oil Breaker Replacements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	183	557	446	352
Station Oil Containment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	346	707	307
Distribution Transformer Replacements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	592	1,814
Minimum Oil Circuit Breaker Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	947	966
Transmission Sustainment															-	-	-	-	-
Transmission Line Condition Assessment	616	152	647	1,329	427	413	496	343	461	459	498	461	502	502	684	284	363	496	378
Transmission Line Rehabilitation	1,763	829	1,884	1,329	1,639	1,392	1,888	1,561	1,228	1,216	3,006	2,501	2,235	2,544	3,444	3,305	2,446	1,880	2,338
Transmission Line Urgent Repairs	257	352	308	362	338	526	343	353	414	412	446	490	498	498	313	343	339	370	351
Transmission Line Right of Way Easements	150	170	135	140	311	395	346	267	354	352	407	439	414	414	357	393	400	402	410
38 Line Lake Rehabilitation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	724	-	-	-
19 Line/29 Line Reconfiguration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	265	-	-	-	-
Distribution Sustainment														-	-	-	-	-	-
Distribution Line Condition Assessment	637	928	678	692	599	659	667	605	1,904	2,222	891	847	1,447	1,491	1,024	1,175	1,239	1,277	1,321
Distribution Line Rehabilitation	1,606	1,174	3,590	2,720	2,848	2,626	3,209	2,779	1,854	1,610	3,452	2,882	2,457	1,697	2,524	2,241	2,572	2,714	2,797
Distribution Urgent Repairs	1,228	535	1,414	2,525	1,911	1,706	1,805	1,363	975	1,080	2,115	2,313	2,067	2,852	1,682	1,866	2,013	1,864	1,965
Distribution Line Rebuilds	1,576	1,167	1,945	1,263	1,178	1,072	1,167	1,031	751	685	1,393	1,051	1,374	2,913	1,608	1,571	1,918	1,956	1,996
Distribution Line Small Planned Capital	339	1,084	378	481	668	596	747	644	1,364	1,463	439	600	395	896	678	693	690	738	729
Environmental Compliance (PCB Mitigation)	857	962	868	92	700	152	700	-	-	-	-	-	-	-	-	1,214	1,649	1,683	1,717
Forced Upgrades and Lines Moves	1,168	1,565	1,400	770	1,255	1,908	1,461	3,265	1,364	1,463	1,828	1,151	2,321	2,231	1,736	1,311	1,524	1,700	1,618
Underground Switcher Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	286	183	271	-	-
Underground Cable Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	1,404	548	530	541	552	563
ArcFM Feeder System Audit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	254	-	-	-	-
Telecommunication																			
Station Smart Device Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	243	248	253	258	264
Backbone Transport Technology Migration	-	-	-	-	-	-	-	-	-	-	14	28	-	(28)	-	-	820	837	-
Communication Upgrades	304	126	414	435	299	238	111	-	275	234	403	388	318	414	414	422	325	331	339
SCADA Systems Sustainment	-	-	-	-	-	-	-	-	-	-	718	767	584	759	585	596	608	620	633

Note: Above numbers exclude costs of removal. Expenditures for 2014-2018 are presented net of loadings and AFUDC.

39.0 Reference: Exhibit B-1, Section C5, pp. 207-216

Transmission and Stations and Distribution Growth Capital

39.1 For each project described in Sections 5.5.3 and 5.5.4, please provide a table showing annual amounts for approved and actual expenditures since inception (or since 2007 for on going programs) and forecast to completion, and provide a comparison, if applicable, to similar projects proposed in FortisBC's 2012 Long Term Capital Plan, filed as part of the 2012 Integrated System Plan.

Response:

The requested table is provided below.

	2007		2008		2009		2010		2011		2012		2013		2014	2015	2016	2017	2018
Transmission & Stations Growth	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	($000s)																		
42 Line Meshed Operation (Huth and Oliver)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-
Voltage Support in Boundary Area	-	-	-	-	-	-	-	-	-	-	-	-	-	-	489	761	-	-	-
Huth 8 Kv Transformer Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,280	1,306	-	-	-
GLE LV Bus Capacity Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	279	-
Reconductor 52 Line & 53 Line	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	676
Summerland Substation Transformer Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,252
Spall Breaker House Reconfiguration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,162	-	-	-	-
Saucier Substation Protection and Metering Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	911	-	-	-
Distribution Growth																			
New Connects System Wide	14,490	21,918	15,954	24,434	23,564	15,833	19,070	15,927	21,584	16,409	22,276	15,665	17,026	16,070	12,407	12,598	12,527	12,857	13,276
Small Growth Projects	446	514	210	1	-	-	137	123	751	685	1,075	639	678	932	929	855	884	902	920
Distribution Unplanned Growth	685	1,065	713	834	974	604	994	750	986	981	839	777	523	730	725	695	660	702	737
Kaleden Feeder 1 Capacity Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	686	-	-	-	-
Fault Indicator Installation	-	-	-	-	-	-	-	-	-	-	-	-	-	153	-	306	312	-	-
Grand Forks Terminal Feeder Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	933	953	-
DG Bell Feeder 4 Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,689

Note: Above numbers exclude costs of removal. Expenditures for 2014-2018 are presented net of loadings and AFUDC.

40.0 Reference: Exhibit B-1, Section C5, pp. 226-231
Certificates of Public Convenience and Necessity

40.1 Please confirm that FortisBC will not proceed with the implementation of any portion of any project described in Section 5.7 without first filing an application for a CPCN and receiving approval thereof.

Response:

Confirmed.

41.0 Reference: Exhibit B-1, p. 247

The distinction made by the Commission in the G-110-12 decision is not consistent with the BCUC's approved treatment of FBC's deferral accounts prior to 2012 and is also not consistent with the treatment of deferred accounts for FEI.

41.1 Please confirm that the distinction made by the Commission in the G-110-12 decision is consistent with the approved treatment of FBC's deferral accounts for other electric utilities in the province?

Response:

FBC interprets the question to ask whether the Commission's treatment in G-110-12 is consistent with the treatment of BC Hydro's deferral accounts.

FBC understands that BC Hydro's deferred accounts are financed at its Weighted Average Cost of Debt (WACD). The Company believes that a comparison between an investor-owned electric utility and a Crown corporation with respect to financing is less relevant than a comparison to other investor owned utilities.

A number of characteristics that bear on the question of deferred charge financing differ between investor-owned utilities (FBC and FEI) and publicly-owned utilities (BC Hydro), including:

- BC Hydro's status as a non-taxable crown corporation;
- BC Hydro's access to low-cost financing, as a government entity;
- BC Hydro's Return on Equity has at times included a premium which was set by direction of the provincial government;
- BC Hydro's capital structure being established and revised by direction of the provincial government, including a deemed equity component that is higher than the actual equity in BC Hydro's books and at times including both a debt and equity return on the difference between deemed equity and book equity; and
- In addition, BC Hydro's deferral accounts are recorded (and financed) on a gross basis, while FBC's and FEI's deferral accounts are recorded net of tax.

Overall, the government sets the level of return it receives from its investment in BC Hydro and there are many ways in which the return can be affected. It is not appropriate to compare the way in which an investor-owned utility achieves a return to the multi-faceted methods at the government's disposal since it is not an "apples to apples" comparison.

As an investor-owned utility, FBC should earn an equity return (through rate base treatment) on its deferral accounts in order to earn a fair return on its invested capital, since deferral accounts are financed as a part of the Company's total investment. It has been a long standing practice in BC for investor owned utilities to have deferral accounts included as part of utility base and therefore attracting a full rate base return. Removing these deferral accounts from rate base is simply a way of artificially decreasing the Company's return on invested capital.

42.0 Reference: Exhibit B-1, p. 253, Table D3-1

42.1 Please provide the capitalized overhead rate for electric utilities of Fortis, and the excerpt of the regulatory decisions that approved the capitalized overhead rate for those utilities?

<u>Response:</u>

Utility	Capitalization Rate	Comments
FortisAlberta	17.8% of gross O&M for 2011 and 19% for 2012.	• Some overhead expenses are capitalized as property, plant and equipment and others are capitalized as a separate regulatory asset
FortisOntario	Effectively zero.	• As directed by the Ontario Energy Board, Ontario utilities have been directed to apply a modified IFRS capitalization policy and applies IAS 16 and therefore does not capitalize any overheads.
Maritime Electric	Approximately 2.6% of gross O&M.	• The Prince Edward Island Regulatory and Appeals Commission has not provided any direct regulatory decisions nor performed any detailed review or examination of Maritime Electric's Capitalized Overhead.
Newfoundland Power	6.8% of gross O&M based on 2013 forecast.	• Capitalization based on effort associated with capital work. • The Company uses the incremental cost method of accounting for the purpose of capitalization of general expenses.

Excerpts for each entity are included in Attachment 42.1.

43.0 Reference: Exhibit B-1, p. 267

FBC requests approval for financing of the non rate base account at the Company's WACC rate during 2013, and further seeks approval to transfer the balance in each of these subaccounts (Sections 4.4.8 to 4.4.13) as at December 31, 2013 to rate base on January 1, 2014.

43.1 Please confirm that if the Commission denies the FortisBC request to change the distinction in Order G-110-12 regarding deferral account financing that the Commission should also deny the request to finance the referenced accounts at the Company's WACC?

<u>Response:</u>

Not confirmed. As presented in Section D3.2 beginning on Page 246 of the Application, the Company has established why these deferral accounts should attract financing costs at the Weighted Average Cost of Capital (WACC). FBC does not agree with the Commission's conclusions regarding the financing of deferral accounts in its Order G-110-12.

44.0 Reference: Exhibit B-1, Section D3, pp. 251-257

Capitalized and Direct Overheads

44.1 Please provide a detailed table showing the combined and direct overheads charged to each category of capital projects annually since 2007 (similar categories as Table C5-2, or as may otherwise be appropriate to categorize projects). Please provide the amounts on both an absolute amount and as a percentage of the overall capital expenditure for each category of projects.

Response:

The following tables detail the approximate amount of Direct and Capitalized Overheads charged to the various categories of capital projects. Please note that the higher relative percentages in 2012 are a result of lower actual capital expenditures in 2012 due to the fact that the 2012 – 2013 revenue requirements application was not approved until August 15, 2012.

		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Approved	
		($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total
Direct Overhead															
Generation	Growth	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
	Sustaining	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
		-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Transmission and Stations	Growth	3,763	3.3%	2,666	3.2%	3,222	3.7%	3,653	3.2%	1,941	3.0%	632	1.5%	40	0.1%
	Sustaining	423	0.4%	571	0.7%	516	0.6%	324	0.3%	783	1.2%	1,546	3.6%	1,875	2.7%
		4,187	3.7%	3,237	3.9%	3,739	4.3%	3,977	3.5%	2,724	4.2%	2,178	5.0%	1,915	2.8%
Distribution	Growth	536	0.5%	875	1.1%	650	0.7%	422	0.4%	1,240	1.9%	1,337	3.1%	1,343	1.9%
	Sustaining	1,004	0.9%	831	1.0%	1,119	1.3%	758	0.7%	850	1.3%	1,026	2.4%	1,393	2.0%
		1,540	1.4%	1,707	2.1%	1,769	2.0%	1,180	1.0%	2,090	3.2%	2,363	5.5%	2,735	3.9%
General Plant		-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total Direct Overhead		**5,727**	**5.1%**	**4,944**	**6.0%**	**5,508**	**6.3%**	**5,157**	**4.5%**	**4,814**	**7.4%**	**4,541**	**10.5%**	**4,650**	**6.7%**

		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Approved	
		($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total	($000s)	% of Total
Capitalized Overhead															
Generation	Growth	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
	Sustaining	1,380	1.2%	1,470	1.7%	1,735	1.9%	1,311	1.1%	2,292	3.3%	1,461	3.1%	352	0.5%
		1,380	1.2%	1,470	1.7%	1,735	1.9%	1,311	1.1%	2,292	3.3%	1,461	3.1%	352	0.5%
Transmission and Stations	Growth	4,198	3.5%	3,510	4.0%	3,801	4.1%	5,242	4.4%	2,494	3.6%	1,017	2.1%	57	0.1%
	Sustaining	472	0.4%	752	0.9%	609	0.7%	465	0.4%	1,006	1.4%	2,489	5.2%	2,703	3.7%
		4,671	3.9%	4,262	4.9%	4,410	4.7%	5,706	4.7%	3,500	5.0%	3,506	7.3%	2,761	3.7%
Distribution	Growth	598	0.5%	1,152	1.3%	767	0.8%	606	0.5%	1,593	2.3%	2,152	4.5%	1,936	2.6%
	Sustaining	1,120	0.9%	1,094	1.2%	1,320	1.4%	1,087	0.9%	1,092	1.6%	1,651	3.5%	2,008	2.7%
		1,718	1.4%	2,247	2.6%	2,087	2.2%	1,693	1.4%	2,686	3.8%	3,803	8.0%	3,944	5.3%
General Plant		1,067	0.9%	1,083	1.2%	1,082	1.2%	819	0.7%	2,300	3.3%	2,200	4.6%	4,468	6.0%
Total Capitalized Overhead		**8,836**	**7.4%**	**9,062**	**10.3%**	**9,315**	**10.0%**	**9,529**	**7.9%**	**10,777**	**15.4%**	**10,969**	**23.0%**	**11,524**	**15.6%**

45.0 Reference: Exhibit B-1, Section E, pp. 277-304

Financial Schedules

45.1 Please extend the tables in Financial Schedules showing actual values from 2007.

<u>Response:</u>

Please refer to Attachment 45.1.

46.0 Reference: Exhibit B-1-1 FortisBC Semi-Annual DSM Report Ending December 2012, p. 10, and Power Sense Industrial Efficience Program Evaluation, Sampson Research Consulting, p. 2

Industrial sector costs incurred by the Company were $173,000 for the period, or 49 per cent of the Plan.

Feedback provided via the site visits and the participant survey …

Communication between delivery staff and program management is frequent.

46.1 Please provide industrial sector costs as per cent of Plan achieved for the past five years?

Response:

Table 1 provides industrial sector costs as per cent of Plan achieved for the past five years.

Table 1

	Industrial Costs (Plan) ($ 000's)	Industrial Costs (Actual) ($ 000's)	% of Plan Achieved
2008	200	147	73%
2009	345	236	68%
2010	389	241	62%
2011	613	137	22%
2012	350	173	49%

46.2 Please comment on whether or not the site visits and the participant survey included the Celgar mill in Castlegar?

Response:

The Celgar mill in Castlegar participated in the evaluation of the Industrial Efficiency Program. The evaluation participant received a site visit and a Celgar representative answered the participant survey.

46.3 Please identify and explain all incentive and program changes FortisBC has considered since the 2012-13 RRA and ISP proceeding in the industrial sector?

Response:

FBC left the Industrial Efficiency program largely unchanged, including the incentive level (10 cents per annual kWh saved). The plan budget was reduced due to the previous underspend (please refer to the response to ICG IR 1.46.1) and commensurate to the overall DSM budget target. The EMIS measure was removed as a stand-alone offer, but would be available to an interested customer under the Industrial Efficiency program.

46.4 Please confirm that the measure incentive for the industrial efficiency program remains at 10 cents/kWh?

Response:

Confirmed.

46.5 Please comment on whether or not Sampson Research Consulting considered the success of DSM programs in the BC Hydro service area?

Response:

The evaluation of FortisBC's Industrial Efficiency Program did not address or reference DSM programs within BC Hydro's service area.

46.6 Please comment on whether or not Samson Research Consulting considered the submissions and requests of the ICG regarding the FortisBC DSM incentives and programs in the 2012-13 RRA and ISP proceeding?

Response:

The evaluation did not generally review or otherwise consider submissions and requests of the ICG in the 2012-13 RRA and ISP proceedings, with the specific exception of exploring the participants' project payback criteria.

All companies who received an incentive from the Industrial Efficiency Program during the years 2007-2010 were eligible to participate in the program evaluation. Of those program participants where contact was established and agreement to participate in the evaluation received, all were provided with the opportunity to indicate their satisfaction with various aspects of the program and to provide feedback on how FortisBC could improve their satisfaction with the program.

46.7 Please comment on whether or not Sampson Research Consulting considered the FortisBC DSM measure incentive of 10 cents/kWh, or the ForitsBC contribution to consulting or study services?

Response:

The evaluation assessed program incentive criteria by querying evaluation participants on the internal payback period required for financial investments in energy and non-energy capital projects. The payback period for customers is directly related to the incentive levels they receive. This was supplemented with solicited and unsolicited feedback from evaluation participants and program field representatives on the program's incentive structure and incentive amounts, including financial contributions to energy studies.

46.8 Please confirm that there is a material difference in the measure incentives made available by BC Hydro and by FortisBC? If confirmed, please quantify the difference?

Response:

Due to the myriad of BC Hydro industrial sector program offers, compared to FBC's single Industrial Efficiency program offer, it is not possible to ascertain, compare and/or quantify a material difference (if any) in measure incentives.

The matter of the differential in incentives rates was examined at some length in the FBC 2012-13 RRA and ISP proceedings. The Commission's determination (G-110-12 on p.139) follows:

> *"The Commission Panel does not accept ICG's request to direct FortisBC to match BC Hydro's industrial incentives or to implement an energy manager program. The Commission Panel acknowledges that BC Hydro does offer larger incentives to its industrial customers. However, we are not persuaded that BC Hydro's level of incentive is necessarily optimal and that FortisBC should move to that level."*

46.9 Please comment on whether or not FortisBC has considered increasing the DSM incentives as a means to increasing DSM savings.

Response:

FortisBC always considers incentive levels when developing a DSM portfolio. Please also refer to the responses to CEC IRs 1.5.3 and 1.5.3.1.

Attachment 22.1

Argus US Electricity

Incorporating the Energy Market Report

Power Market Prices and Analysis | Issue 13-091 | 13 May 2013

Day-ahead peak prices

Trade date 13-May-13

	$/MWh	Price*	Change	Low	High	MW	Trades
East	NY G	40.50	-9.00	40.00	41.00	-	-
	PJM W	41.25	1.50	40.75	41.75	-	-
	NE Pool	40.50	-6.75	40.00	41.00	-	-
ERCOT	Houston	37.75	3.00	37.25	38.25	-	-
	North	39.20	4.71	38.75	39.75	1,080	13
	South	38.00	3.75	37.50	38.50	-	-
	West	36.25	2.50	35.75	36.75	-	-
Midwest	Indiana	38.25	-1.50	37.75	38.75	-	-
	N. Ill.	39.50	4.75	39.00	40.00	-	-
	PJM AD	41.50	2.25	41.00	42.00	-	-
Southeast	Entergy	35.75	0.75	35.25	36.25	-	-
	Southern	36.00	0.00	35.50	36.50	-	-
West	COB	41.00	0.00	40.50	41.50	-	-
	Four Corners	36.50	-1.25	36.00	37.00	-	-
	Mead	45.25	3.16	44.75	45.75	-	-
	Mid-C	38.85	4.18	35.50	40.00	884	30
	Mona	34.50	-1.50	34.00	35.00	-	-
	NP 15	48.25	-0.75	47.75	48.75	-	-
	Palo Verde	42.95	3.45	42.50	43.00	250	7
	SP 15	59.25	-1.00	58.75	59.75	-	-

Day-ahead off-peak prices

Trade date 13-May-13

	$/MWh	Price*	Change	Low	High	Volume	Trades
East	NY G	34.00	0.00	33.50	34.50	-	-
	PJM W	30.75	-0.75	30.25	31.25	-	-
	NE Pool	32.50	-0.50	32.00	33.00	-	-
ERCOT	Houston	24.00	-0.50	23.50	24.50	-	-
	North	24.50	0.25	24.50	24.50	650	5
	South	24.00	-0.50	23.50	24.50	-	-
	West	20.50	-3.75	20.00	21.00	-	-
Midwest	Indiana	26.00	-3.25	25.50	26.50	-	-
	N. Ill.	24.25	2.00	23.75	24.75	-	-
	PJM AD	31.25	2.50	30.75	31.75	-	-
Southeast	Entergy	23.75	-2.50	23.25	24.25	-	-
	Southern	25.50	-3.75	25.00	26.00	-	-
West	COB	8.75	-11.00	6.50	10.00	100	4
	Four Corners	22.75	-2.25	22.25	23.25	-	-
	Mead	27.75	-3.16	27.00	28.00	200	3
	Mid-C	1.98	-7.32	0.25	5.00	2,427	77
	Mona	22.00	-1.00	21.50	22.50	-	-
	NP 15	31.25	-3.50	30.75	31.75	-	-
	Palo Verde	25.92	-4.15	24.50	27.00	150	6
	SP 15	34.50	-9.25	34.00	35.00	-	-

* When MW and trade number are blank, the low/high/price represent bid/ask/assessment. When MW and trade number have values, low/high/price represent low trade, high trade and volume-weighted average

News

East

Northeast day-ahead peak prices **fell sharply today despite increased regional spot natural gas prices.** New York G and New England both priced at $40.50/MWh, down 18pc and 14pc, respectively.

Continued on page 2

Midwest

Daily power markets today responded modestly to forecasts for higher temperatures across the midwest tomorrow. Peak loads rise 8pc tomorrow and peak for the week on 15 May. **Indiana peak slipped and AEP-Dayton gained in similar measure.**

Continued on page 5

West

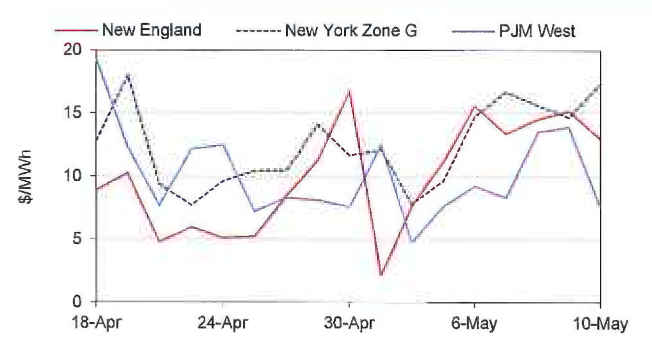
Day-ahead off-peak prices tumbled at west coast trading hubs today on expectations for surging wind output from the northwest to southern California. Mid-Columbia's average slipped into the low single digits, with some packages going for pocket change.

Continued on page 9

ERCOT

Texas day-ahead prices got a boost from more load on the system tomorrow. Weather forecasts are little changed and wind generation rises. The peak shape at North rose 13pc. **More wind kept light-load prices steady.**

Northeast peak gas spark spreads



Inside

- Heating demand persists in the east 2
- SPP heats up 5
- California demand relief in sight 9
- Gas gains interest just under $4 13

East Markets

Continued from page 1

• New England will experience 56 heating degree days (HDDs) for the week ending 18 May, nine below the historical average. The mid-Atlantic will have 54 HDDs, four more than average. **The south Atlantic's 21 HDDs would be seven more than average.** The south Atlantic will also have 37 cooling degree days, two less than normal.

• Independent System Operator-New England declared a minimum generation emergency warning from midnight to 7am ET today as generation threatened to exceed demand. **Real-time prices during that period went from a low of $8 to a high of $48.**

• **The grid operator is expecting a peak load of 15,060MW today, the lowest level all week, increasing to 15,090MW tomorrow but dropping to 15,080MW on 15 May.** The region will also experience 7,399MW of generation outages today, rising to 7,526MW tomorrow and 8,491MW on 15 May.

• New York ISO peak load was expected to be 18,120MW today, decreasing slightly tomorrow but then rising progressively until a weekly peak of 18,956MW on 17 May. **Peak in New York City was forecast to be 6,115MW today, increasing 9.3pc to a weekly high of 6,684MW on 17 May.** Long Island load should be 2,473MW today and little changed tomorrow.

• Peak load in PJM's mid-Atlantic region today was forecast for 30,612MW, decreasing to 30,587MW tomorrow before increasing to 31,034MW on 15 May. **PJM West peak load will be 46,113MW today, decreasing less than 1pc tomorrow.** Load there will peak for the week at 49,783MW on 16 May. The grid operator is expecting total generation outages of 27,558MW tomorrow, decreasing 2.7pc to 26,811MW on 15 May. The weekly peak will be 29,513 on 18 May.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	NYISO G	8,824	8.37	3.78	-5.40	-14.58	-28.35	-42.12
	PJM West	10,160	12.83	8.77	0.65	-7.47	-19.65	-31.83
	NE Pool	9,081	9.28	4.82	-4.10	-13.02	-26.40	-39.78
	Southern	8,856	7.54	3.48	-4.65	-12.78	-24.98	-37.17
Off-peak	NYISO G	7,407	1.87	-2.72	-11.90	-21.08	-34.85	-48.62
	PJM West	7,574	2.33	-1.73	-9.85	-17.97	-30.15	-42.33
	NE Pool	7,287	1.28	-3.18	-12.10	-21.02	-34.40	-47.78
	Southern	6,273	-2.96	-7.02	-15.15	-23.28	-35.48	-47.67

Forward markets $/MWh

	PJM West				NEPOOL			New York A			New York G			New York J		
	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Jun-13	50.40	21.95	19.52	31.45	59.25	20.40	41.10	44.15	15.05	31.50	60.25	21.40	37.90	64.75	35.61	40.70
Jul-13	61.75	32.69	30.53	35.95	61.65	28.57	40.50	51.75	21.98	36.20	68.35	35.27	43.15	74.50	44.43	45.85
Aug-13	58.10	28.94	29.92	33.50	57.65	25.18	38.15	48.25	18.34	33.50	64.90	32.43	40.25	71.00	41.05	43.00
Sep-13	48.05	19.48	20.43	31.90	46.60	15.61	35.30	42.35	13.53	31.50	51.55	20.56	35.60	54.60	25.82	36.55
Oct-13	43.70	14.97	14.92	32.65	44.90	13.56	35.30	40.65	11.60	32.25	49.55	18.21	36.30	51.45	22.37	36.95
Nov-13	43.70	14.00	15.49	33.60	51.80	13.47	40.45	41.20	10.64	32.65	49.80	11.47	38.40	53.20	22.43	39.65
Sum-13	59.90	30.79	30.20	34.75	59.70	26.93	39.35	50.00	20.16	34.85	66.60	33.83	41.70	72.75	42.74	44.40
Q4-13	44.20	13.87	15.71	33.65	56.55	13.19	44.75	41.70	11.34	33.20	54.00	10.64	41.05	56.45	22.95	42.00
Win-14	47.75	12.84	19.02	37.90	90.10	15.94	69.90	47.25	15.75	39.20	71.90	-2.26	54.70	74.75	30.76	55.30
Spr-14	44.90	15.14	16.32	33.85	50.75	13.71	38.85	38.25	7.68	33.10	47.35	10.31	38.65	51.25	20.26	39.50
Sum-14	58.75	29.50	28.63	33.75	56.10	24.58	36.75	48.85	18.85	33.30	65.75	34.23	39.40	69.75	40.10	41.50
Q4-14	43.25	12.45	14.38	32.40	55.15	10.53	44.15	40.40	9.55	31.75	50.85	6.23	36.80	52.85	21.93	38.60
Win-15	48.00	13.18	18.79	37.25	78.85	10.71	56.55	46.50	14.30	38.10	66.40	-1.74	49.55	70.30	27.99	50.95
Spr-15	44.50	14.05	15.41	33.35	49.50	12.25	40.10	40.80	9.76	32.65	50.00	12.75	36.85	53.30	22.06	38.50
Cal-14	47.90	17.34	18.83	33.30	58.05	15.21	43.50	42.65	12.27	33.00	56.15	13.31	39.75	59.20	26.76	41.00
Cal-15	48.25	17.41	18.78	33.50	55.30	13.69	41.65	42.90	12.15	33.10	55.70	14.09	39.90	59.75	27.30	41.85
Cal-16	48.75	17.39	18.12	33.80	52.20	11.51	39.25	42.65	11.55	33.10	55.35	14.66	40.30	59.25	26.62	42.75
Cal-17	49.75	17.70	18.49	34.50	51.55	12.76	38.70	44.10	12.25	33.15	59.55	20.76	40.85	62.00	28.77	42.90

East Markets

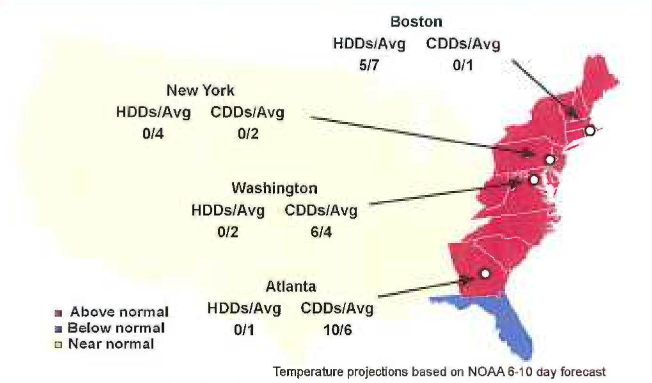
Spot natural gas in $/mmBtu

Location	Average	Low	High
Col Gas Appalachia	3.965	3.955	3.990
Dominion South Point	3.970	3.930	4.040
Florida Gas, zone 3	3.930	3.900	3.960
Texas Eastern zone M3	4.060	4.030	4.090
Transco zone 4	3.930	3.915	3.960
Transco zone 6 NY	4.135	4.080	4.200

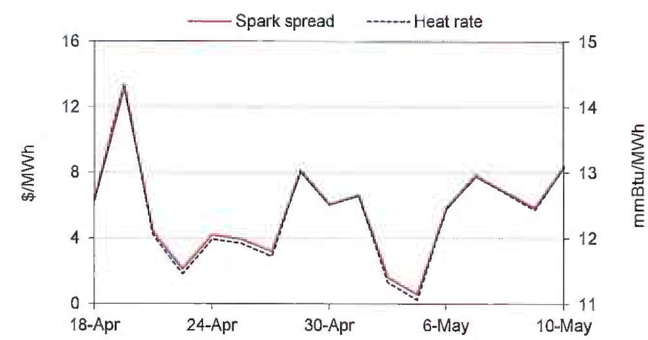
Forward natural gas in $/mmBtu

Location	June	Jun 2013-Oct 2013	Nov 2013-Mar 2014
Columbia Gas App.	3.963	3.986	4.174
Dominion South Pt.	3.905	3.924	4.174
Florida Gas Zone 3	4.033	4.100	4.239
Texas Eastern M-3	4.065	4.101	4.581
Transco Zone 4	3.953	3.991	4.215
Transco Zone 6 NY	4.163	4.193	5.420

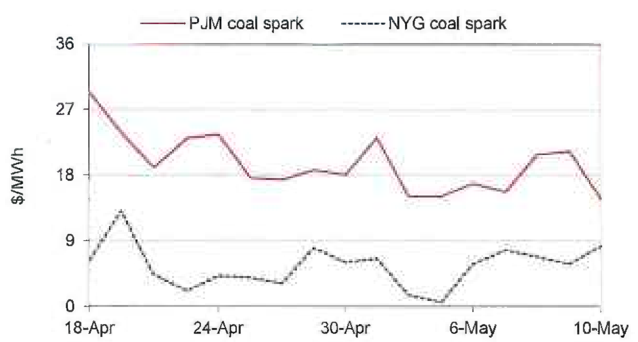
Degree days outlook vs temperature: 19-May



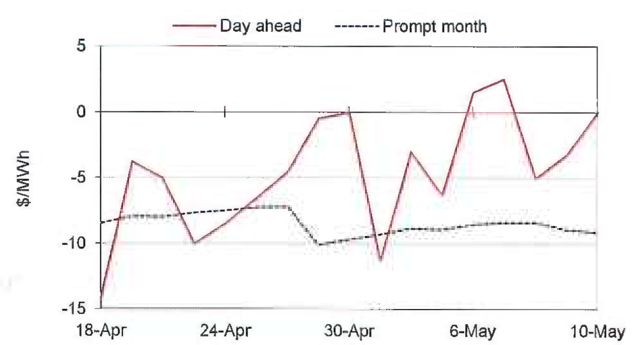
Carbon-adjusted coal generation: NYG



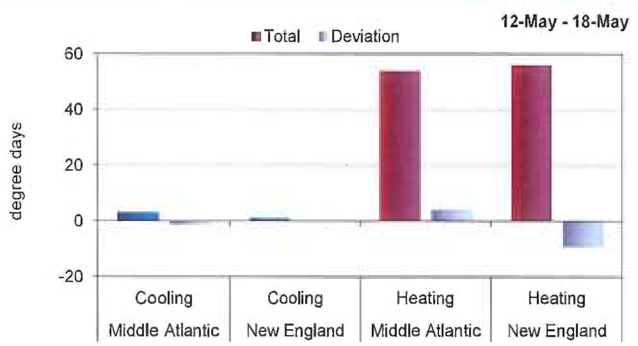
Carbon-adjusted coal spark spreads



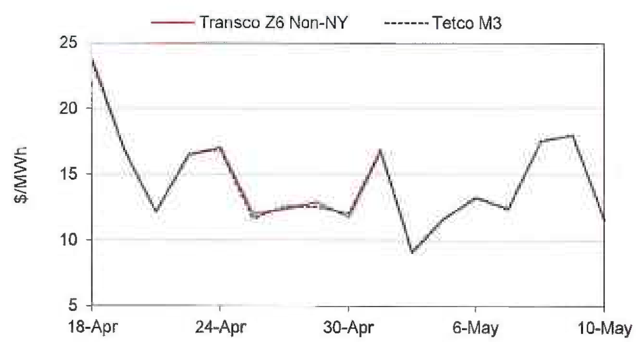
Indiana - PJM W, daily and prompt month spreads



Degree days

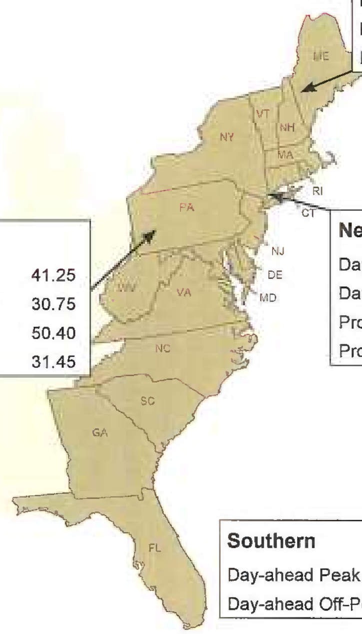


PJM West implied spark spreads



East Prices at a Glance $/MWh

Day-ahead markets for 13-May-13



New England	
Day-ahead Peak	40.50
Day-ahead Off-Peak	32.50
Prompt Peak	59.25
Prompt Off-Peak	41.10

PJM West	
Day-ahead Peak	41.25
Day-ahead Off-Peak	30.75
Prompt Peak	50.40
Prompt Off-Peak	31.45

New York zone G	
Day-ahead Peak	40.50
Day-ahead Off-Peak	34.00
Prompt Peak	60.25
Prompt Off-Peak	37.90

Southern	
Day-ahead Peak	36.00
Day-ahead Off-Peak	25.50

Day-ahead minus hourly spread

10-May-13	Peak	Off-Peak
ISO NE		
Internal Hub	8.84	-2.84
Phase I/II	8.37	-3.03
NY ISO		
Zone A	7.62	-2.22
Zone G	9.45	-2.26
Zone J	4.27	-1.13
Cross Sound	7.53	-2.33
PJM		
PJM Western Hub	3.60	1.42
PJM Eastern Hub	1.16	1.06
PJM Dominion Hub	-6.06	1.70
PJM New Jersey Hub	5.30	1.21

Hourly price averages

	Peak		Off-peak	
	10-May-13	9-May-13	10-May-13	9-May-13
ISO NE				
Internal Hub	39.75	45.63	35.39	37.08
Phase I/II	39.05	44.89	34.93	36.55
NY ISO				
Zone A	33.14	36.84	31.79	31.91
Zone G	37.55	41.27	34.51	34.34
Zone J	48.71	50.54	34.77	34.40
Cross Sound	38.32	40.34	34.09	34.19
PJM				
PJM Western Hub	42.65	41.96	27.58	29.16
PJM Eastern Hub	46.59	43.41	28.48	29.90
PJM Dominion Hub	53.26	42.01	27.65	29.04
PJM New Jersey Hub	42.98	42.86	28.35	29.75

Emissions-adjusted dark spreads

	Peak	Off-peak	24-hour
Nepool	18.45	10.45	15.78
New York G	2.61	-3.89	0.44
PJM West	16.49	5.99	12.99
Southern	-0.55	-11.05	-4.05

Note: Dark spreads are derived first by determining the value for a representative mix of coals and their transportation to the power hub. After adjusting for the amount of sulfur output from that proportionate coal mix in the production of a megawatt hour, the value of SO_2 allowances under current regulations is added to the cost of generation (heat rate 10 mmBtu/MWh x mmBtu value of the coal). This cost of generation is subtracted from the day's power hub clearing price, which is either the *Argus* index or assessment.

Day-ahead peak spreads

	New England	NY G	PJM West	Indiana	AEP Dayton	Northern Ill	Southern
New England	—	0.00	-0.75	2.25	-1.00	1.00	4.50
NY G	0.00	—	-0.75	2.25	-1.00	1.00	4.50
PJM West	0.75	0.75	—	3.00	-0.25	1.75	5.25
Indiana	-2.25	-2.25	-3.00	—	-3.25	-1.25	2.25
AEP Dayton	1.00	1.00	0.25	3.25	—	2.00	5.50
Northern Ill	-1.00	-1.00	-1.75	1.25	-2.00	—	3.50
Southern	-4.50	-4.50	-5.25	-2.25	-5.50	-3.50	—

Sources: ISOs, Argus assessments

Midwest Markets

Continued from page 1

- **Imbalance prices should rise tomorrow in the Southwest Power Pool (SPP)** as temperatures are forecast to jump in the northeastern region of the pool. Peak coincident loads in the SPP reserve sharing group rise almost 10pc tomorrow to 54,101MW.

- Federal forecasters are calling for **high temperatures in the mid-90s F tomorrow in Lincoln, Nebraska**, with similar conditions expected in eastern Kansas and western Missouri. Weather cools the following day, though, with forecasts in the upper-70s F, which could result in ramping-related price volatility.

- **Nebraska is forecast 42 cooling degree days (CDDs) for the week ending 18 May**, according to the National Weather Service. The state has recorded an average of 14 CDDs for the week over the last 30 years. Cooling demand in Iowa and Missouri is also expected to be greater when compared with historical averages – with forecasts of 30 and 32 CDDs, respectively.

- The Texas weather outlook for this week continues to be similar to historical trends. **Peak demand forecasts for the week are little changed from last year's actual loads.** Grid operator forecasts for 13-19 May 2013 are expected to be highest on 17 May at around 50,700MW, as temperatures rise later in the week in south Texas.

- **The CPC calls for 68 population-weighted CDDs this week in Texas**, 2pc more than normal and 24pc more than was recorded during the same week in 2012. A band through north-central Texas is showing some signs of improvement of drought conditions. Cooling loads in Oklahoma and New Mexico are also expected to be higher year over year for the week.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Indiana	9,884	11.16	7.29	-0.45	-8.19	-19.80	-31.41
	N. Ill.	9,900	11.57	7.58	-0.40	-8.38	-20.35	-32.32
	PJM AD	10,453	13.71	9.74	1.80	-6.14	-18.05	-29.96
	Entergy	9,238	8.66	4.79	-2.95	-10.69	-22.30	-33.91
Off-peak	Indiana	6,718	-1.09	-4.96	-12.70	-20.44	-32.05	-43.66
	N. Ill.	6,078	-3.68	-7.67	-15.65	-23.63	-35.60	-47.57
	PJM AD	7,872	3.46	-0.51	-8.45	-16.39	-28.30	-40.21
	Entergy	6,137	-3.34	-7.21	-14.95	-22.69	-34.30	-45.91

Forward markets $/MWh

	Indiana				Northern Illinois				PJM AD				ERCOT North			
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price
Jun-13	41.65	13.91	8.96	26.55	43.65	15.51	17.91	25.75	45.95	18.21	18.43	29.25	48.55	21.50	21.16	30.20
Jul-13	51.25	23.31	18.33	30.00	55.50	27.11	29.68	30.90	56.35	28.41	28.50	33.05	74.55	47.09	47.08	31.35
Aug-13	47.05	19.13	25.06	27.50	49.00	20.45	23.86	27.50	51.70	23.78	34.94	30.15	98.65	71.08	71.15	37.55
Sep-13	37.90	9.99	15.47	25.10	40.50	12.00	16.11	25.25	42.80	14.89	25.70	29.15	45.20	17.80	18.25	29.65
Oct-13	35.35	7.34	12.57	26.95	36.65	7.69	10.96	23.50	40.10	12.09	22.75	30.20	37.00	9.60	8.66	27.80
Nov-13	35.10	6.52	12.09	26.95	36.95	7.44	11.51	25.00	39.80	11.22	22.27	31.30	35.50	7.76	8.27	27.45
Sum-13	49.15	21.22	21.70	28.75	52.25	23.78	26.77	29.20	54.05	26.12	31.74	31.65	86.60	59.09	59.11	34.45
Q4-13	35.50	6.72	12.72	27.00	36.90	7.17	11.46	24.80	39.95	11.17	22.60	30.90	36.35	8.30	8.57	28.25
Win-14	38.10	7.87	15.19	29.85	39.70	8.55	14.20	30.05	42.20	11.97	24.87	33.45	39.60	10.12	12.09	31.90
Spr-14	36.45	7.43	12.92	27.80	38.30	8.52	12.49	27.85	40.50	11.48	22.70	31.30	39.20	10.97	11.08	29.90
Sum-14	48.35	19.76	24.10	27.60	50.50	21.48	23.95	28.60	52.55	23.96	34.40	30.45	102.55	74.20	73.89	36.30
Q4-14	35.30	5.58	11.96	26.25	36.35	5.98	10.62	23.95	39.10	9.38	21.44	30.05	37.35	8.38	9.32	29.00
Win-15	40.35	9.46	16.26	30.00	41.00	9.04	14.82	32.50	44.35	13.46	26.34	34.30	40.95	10.40	12.86	32.45
Spr-15	37.90	8.54	13.10	26.45	38.20	7.87	11.71	25.30	41.10	11.74	22.58	30.45	39.55	10.51	10.86	29.10
Cal-14	38.80	9.63	15.25	26.85	40.50	10.72	14.69	26.40	42.95	13.78	25.18	30.35	51.55	23.05	23.46	31.15
Cal-15	39.55	9.97	14.83	27.05	40.70	10.47	14.27	26.60	43.35	13.77	24.92	30.55	53.00	23.90	24.39	31.55
Cal-16	40.40	10.70	14.47	27.65	41.00	10.19	13.54	26.95	44.15	14.45	24.73	31.00	52.70	23.09	23.10	31.45
Cal-17	41.55	11.42	14.11	27.15	41.65	10.11	13.38	27.50	45.25	15.12	24.97	31.55	52.05	21.78	21.76	30.90

Midwest Markets

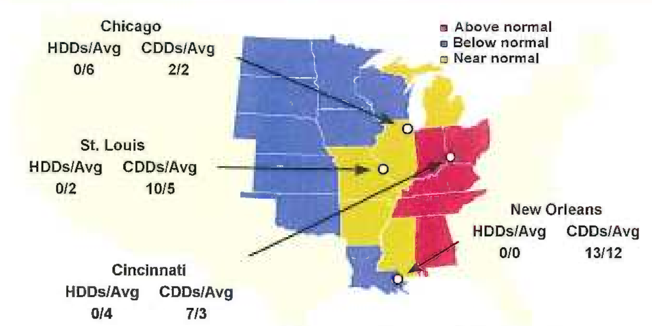
Spot natural gas in $/mmBtu

Location	Average	Low	High
CenterPoint	3.825	3.790	3.850
Chicago Citygates	3.990	3.970	4.060
Mich Con Citygates	4.160	4.142	4.250
NGPL Texok Zone	3.885	3.860	3.900
NNG Ventura	3.875	3.860	3.900
Panhandle OK Mainline	3.735	3.700	3.745

Forward natural gas in $/mmBtu

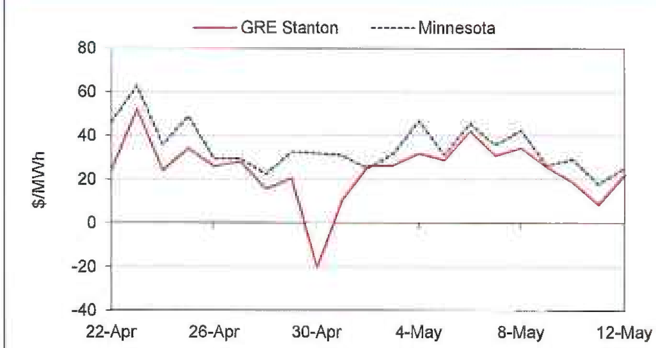
Location	June	Jun 2013-Oct 2013	Nov 2013-Mar 2014
CenterPoint	3.792	3.834	4.037
Chicago Citygates	4.020	4.058	4.302
MichCon Citygate	4.150	4.168	4.332
NGPL Texok Zone	3.895	3.929	4.105
NNG Ventura	3.917	3.948	4.197
Panhandle OK Mainline	3.735	3.774	4.013

Degree days outlook vs temperature: 19-May

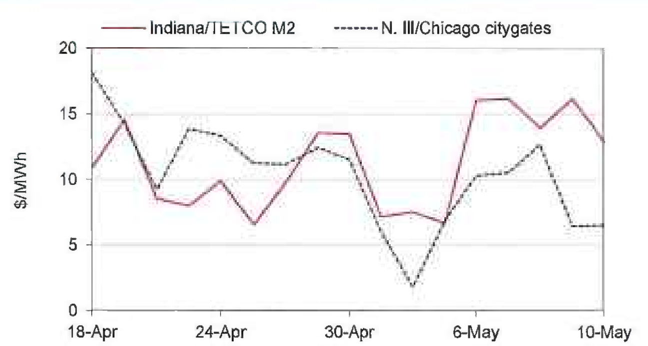


Temperature projections based on NOAA 6-10 day forecast

Average peak price

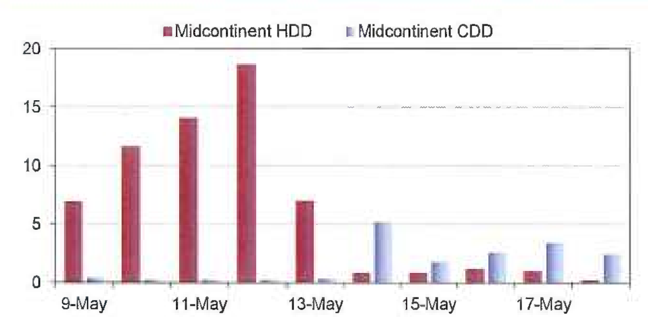


Implied gas spark spreads



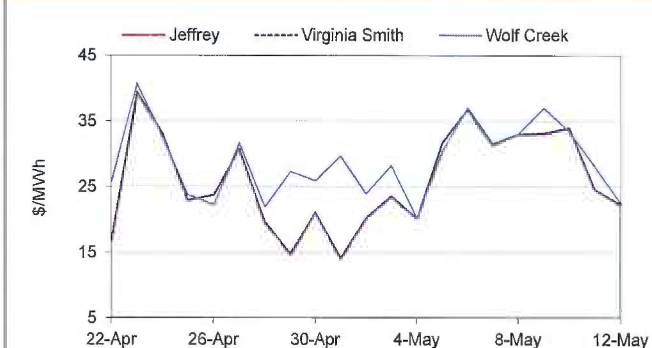
MISO day-ahead minus real-time

Degree days



Data Source: AccuWeather

SPP North nodes LIP



Midwest Prices at a Glance $/MWh

Day-ahead markets for 13-May-13

Indiana	
Day-ahead Peak	38.25
Day-ahead Off-Peak	26.00
Prompt Peak	41.65
Prompt Off-Peak	26.55

PJM AD	
Day-ahead Peak	41.50
Day-ahead Off-Peak	31.25
Prompt Peak	45.95
Prompt Off-Peak	29.25

Northern Ill	
Day-ahead Peak	39.50
Day-ahead Off-Peak	24.25

Entergy	
Day-ahead Peak	35.75
Day-ahead Off-Peak	23.75

Day-ahead minus hourly spread

10-May-13	Peak	Off-Peak
MISO		
Indiana	9.47	8.44
Michigan	9.72	3.01
Minnesota	8.59	6.89
Illinois	19.17	8.52
PJM		
Duke	4.04	1.34
Northern Ill	2.00	1.00
A-D	4.10	1.04

SPP imbalance prices: Flow date — 10-May-13

	Peak	Off-peak
SPP North		
Cooper	33.75	22.62
Gentleman	34.05	22.95
Holcomb	34.59	23.27
Jeffrey	34.03	22.93
Emporia	33.57	23.33
Empire	33.48	23.22
Wolf Creek	33.49	23.27
WAPA-Nebraska	34.05	22.95
SPP East		
Sibley	33.61	23.47
Ameren Missouri	33.60	23.13
AECI	33.56	23.14
SPA-Arkansas	33.57	23.16
SPP South		
Sooner	33.27	23.15
Muskogee	33.43	23.18
Oneta	33.42	23.18
Redbud	33.20	23.11
Seminole	33.46	23.18
Kiamichi	33.57	23.21
Wilkes	33.60	23.19
Arsenal Hill	33.60	23.18
Entergy	33.58	23.15
Cleco	33.58	23.16
Ercot-East	33.61	23.19
Ercot-North	37.28	24.16
SPP West		
Tolk	36.19	23.80
WAPA-Colorado	33.79	22.83
Blackwater	36.18	23.80
EDDY	36.21	23.81

Emissions-adjusted dark spreads

	SO_2 Peak	Off-peak	24-hour average
Indiana	17.07	4.82	12.99
Entergy	6.73	-5.27	2.73
Northern Ill	16.51	1.26	11.42
PJM A-D	15.89	5.64	12.47

Hourly price averages

	Peak		Off-peak	
	10-May-13	9-May-13	10-May-13	9-May-13
MISO				
Indiana	33.53	34.45	20.56	33.60
Michigan	33.55	37.66	28.83	41.30
Minnesota	29.14	26.30	13.69	25.74
Illinois	32.26	40.51	20.49	36.17
PJM				
Northern Ill	32.75	36.88	19.75	14.17
A-D	35.40	41.98	27.96	30.74
Duke	34.49	40.23	26.29	27.67

Day-ahead peak spreads

	Indiana	Northern Ill	PJM A-D	PJM West	Entergy	Southern
Indiana	—	-1.25	-3.25	-3.00	2.50	2.25
Northern Ill	1.25	—	-2.00	-1.75	3.75	3.50
PJM A-D	3.25	2.00	—	0.25	5.75	5.50
PJM West	3.00	1.75	-0.25	—	5.50	5.25
Entergy	-2.50	-3.75	-5.75	-5.50	—	-0.25
Southern	-2.25	-3.50	-5.50	-5.25	0.25	—

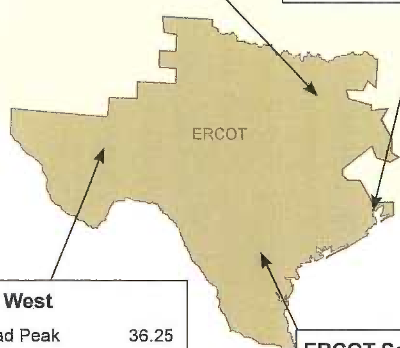
Sources: ISOs, Argus assessments

ERCOT Prices at a Glance $/MWh

Day-ahead markets for 13-May-13

ERCOT North
Day-ahead Peak 39.20
Day-ahead Off-Peak 24.50

ERCOT Houston
Day-ahead Peak 37.75
Day-ahead Off-Peak 24.00

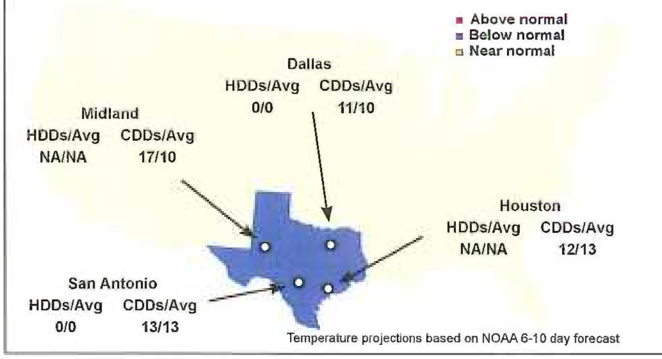


ERCOT West
Day-ahead Peak 36.25
Day-ahead Off-Peak 20.50

ERCOT South
Day-ahead Peak 38.00
Day-ahead Off-Peak 24.00

Houston Ship Channel daily natural gas index *(all Houston Ship Channel transactions)*	**$3.945/mmBtu**

Degree days outlook vs temperature: 19-May



Day-ahead minus real time

12-May	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	7.81	-0.19
North	7.83	-0.19
South	8.06	-0.14
West	6.90	0.15
Load zones		
Houston	7.83	-0.19
North	7.87	-0.19
South	8.67	-0.04
West	28.36	2.77

ERCOT PRB coal dark spreads

(Emissions-adjusted)	Peak	Off-peak	24-hour
Houston	11.99	-1.76	7.41
South	12.24	-1.76	7.58
North	13.44	-1.26	8.54
West	10.49	-5.26	5.24

Note: Dark spreads are derived first by determining the value for a representative mix of coals and their transportation to the power hub. After adjusting for the amount of sulfur output from that proportionate coal mix in the production of a megawatt hour, the value of SO_2 allowances under current regulations is added to the cost of generation (heat rate 10 mmBtu/MWh x mmBtu value of the coal). This cost of generation is subtracted from the day's power hub clearing price, which is either the *Argus* index or assessment.

Day-ahead nodal prices

14-May	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	37.65	24.09
North	37.00	24.14
South	37.89	24.12
West	36.35	20.43
Load zones		
Houston	38.65	24.08
North	37.07	24.11
South	41.55	24.48
West	43.55	20.54
Hub average	**37.24**	**23.20**
Bus average	**37.19**	**23.70**

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Houston	9,569	10.14	6.19	-1.70	-9.59	-21.43	-33.26
	North	10,090	12.01	8.12	0.35	-7.42	-19.08	-30.73
	South	9,845	10.98	7.12	-0.60	-8.32	-19.90	-31.48
	West	9,403	9.27	5.41	-2.30	-10.01	-21.58	-33.14
Off-peak	Houston	6,084	-3.62	-7.56	-15.45	-23.34	-35.18	-47.01
	North	6,306	-2.70	-6.58	-14.35	-22.12	-33.78	-45.43
	South	6,218	-3.02	-6.88	-14.60	-22.32	-33.90	-45.48
	West	5,318	-6.49	-10.34	-18.05	-25.76	-37.33	-48.89

West Markets

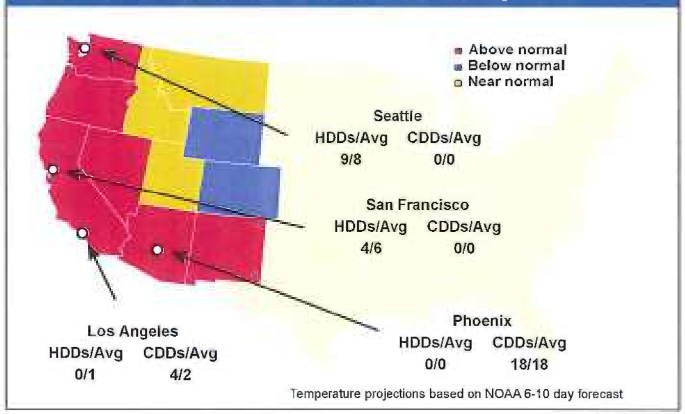
Continued from page 1

• COB nighttime blocks lost about $10/MWh despite commencement of an increased constraint on the California-Oregon Intertie that limits southbound capacity to 3,500MW – down 700MW from last week. SP-15 prices fell in similar measure as the California Independent System Operator (CAISO) showed southern California wind generation ramping up sharply later today and holding to high levels into the overnight period. **Wind output in the SP-15 area is expected to hover around 1,300MW** for most off-peak intervals tomorrow.

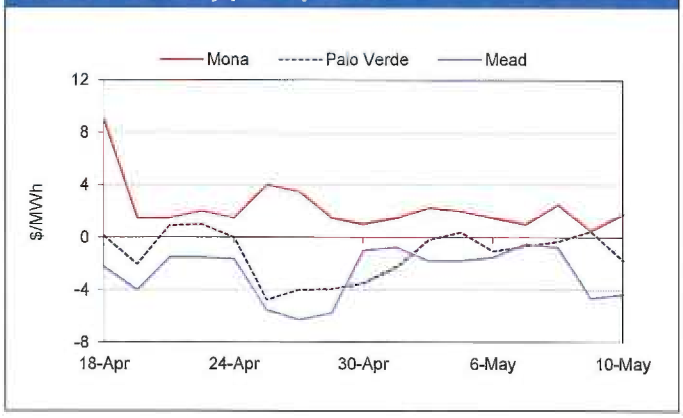
• **Unexpectedly high demand sent SP-15 real-time prices soaring into the $200-260/MWh range at mid-day today,** as the CAISO market cleared higher up in the generation bid stack and regional congestion provided additional upward pressure. Negative congestion farther north held NP-15 prices to the $50 handle. CAISO load was predicted to peak at around 38,520MW today – an increase of nearly 5pc over day-ahead load forecast and 8.5pc above a projection made late last week.

• California load should decline steadily throughout the week on falling temperatures, especially in the Los Angeles metro area. **CAISO expects peak load to drop by about more than 9,000MW by 17 May** – Friday. Peak grid demand should see a 3,600MW decline tomorrow, with much of the drop coming from the south.

Degree days outlook vs temperature: 19-May



Four Corners daily peak spreads



Forward markets $/MWh

	Mid-Columbia				Palo Verde				SP-15				NP-15			Mead		
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Jun-13	32.50	6.25	8.28	12.40	40.00	13.59	12.61	25.15	48.50	21.18	33.16	34.15	42.60	14.44	31.65	41.50	15.09	26.25
Jul-13	42.90	15.89	18.58	28.50	49.00	22.08	21.53	29.50	57.25	29.21	41.82	40.10	50.25	21.56	37.75	50.85	23.93	30.75
Aug-13	47.65	20.84	23.33	34.40	51.50	24.25	24.81	29.35	61.90	33.58	41.31	41.00	55.40	26.63	38.40	53.45	26.20	30.60
Sep-13	42.00	15.19	18.16	33.90	42.10	15.12	15.95	30.20	56.40	28.19	36.22	41.65	50.25	21.03	40.40	43.90	16.92	31.45
Oct-13	37.25	10.09	13.00	32.85	39.05	12.07	11.85	28.50	51.65	23.44	30.71	40.15	46.90	17.43	38.25	40.55	13.57	29.50
Nov-13	38.75	10.69	14.26	33.35	36.50	9.21	9.57	29.30	49.25	20.53	28.51	40.25	46.05	16.00	39.00	38.10	10.81	30.35
Q3-13	44.25	17.38	20.09	32.25	47.75	20.70	20.98	29.70	58.60	30.41	39.87	40.90	52.05	23.16	38.85	49.60	22.55	30.95
Q4-13	39.15	11.00	14.66	34.00	37.65	10.02	10.72	29.20	50.20	21.16	29.46	40.40	46.60	16.43	38.90	39.25	11.62	30.20
Q1-14	37.65	8.08	13.03	31.90	38.40	9.55	11.31	30.60	50.60	20.29	29.69	40.55	43.75	12.64	38.50	40.05	11.20	32.00
Q2-14	28.00	0.25	3.34	13.95	37.80	10.69	10.56	27.70	47.75	18.86	26.69	36.80	42.40	12.46	30.25	39.40	12.29	29.10
Q3-14	41.70	13.28	16.71	29.90	48.05	19.91	20.28	31.30	57.60	27.96	35.74	40.15	53.55	23.07	39.05	50.20	22.06	32.85
Q4-14	40.35	10.92	15.69	34.45	38.90	10.08	11.66	31.45	50.80	20.12	29.74	40.80	49.35	17.57	41.55	40.75	11.93	32.95
Q1-15	40.00	9.49	14.90	34.95	39.95	9.80	12.29	31.30	50.95	18.93	29.45	42.40	48.20	15.49	42.25	41.65	11.50	32.70
Q2-15	29.30	1.07	4.10	15.90	39.35	11.84	11.54	24.70	48.60	18.97	26.88	36.55	42.65	11.89	31.25	41.15	13.64	25.75
Cal-14	36.90	8.10	12.17	27.60	40.75	12.52	13.42	30.25	51.70	21.82	30.48	39.60	47.30	16.47	37.40	42.60	14.37	31.70
Cal-15	38.35	9.00	13.15	28.65	42.10	13.28	14.29	31.05	52.40	21.49	30.68	40.75	49.15	17.34	40.20	44.05	15.23	32.40
Cal-16	39.10	9.15	13.13	28.70	42.80	13.26	13.93	31.90	53.90	22.31	31.06	41.35	50.80	18.35	38.30	45.30	15.76	33.70
Cal-17	42.50	11.80	15.91	31.25	46.15	15.88	16.65	34.30	56.05	23.54	32.54	40.65	53.75	20.73	40.95	48.80	18.53	35.95

West Markets

Western generating unit outages

Capacity	Unit	Owner	Fuel	Begins	Reason
15,907	Total CAISO units curtailed	various	various	NA	planned and unplanned
728	CPV Sentinel	CPV	gas	22-Jan-13	Unplanned
495	Desert Star	SDG&E	gas	19-Jun-12	Planned
407	Helms Pump-Gen 2	PG&E	hydro	26-Sep-11	Planned
830	High Desert	SCE	gas	12-May-12	Planned
933	Hyatt-Thermalito Pump-Gen	CDWR	hydro	2-May-12	@129MW Planned, Unplanned
400	Panoche Energy Center	PG&E	gas	23-Jul-12	Planned
1,124	San Onofre 2	SCE	nuke	10-Jan-12	Planned
1,126	San Onofre 3	SCE	nuke	1-Feb-12	Unplanned
586	Sunrise Aggregate 2	AES	gas	7-Aug-12	Planned

Spot natural gas in $/mmBtu

Location	Average	Low	High
PG&E Citygates	4.055	4.045	4.100
Stanfield	3.760	3.755	3.760
SoCal Gas Co	3.940	3.890	4.040
El Paso San Juan Basin	3.785	3.770	3.830
El Paso Permian Basin	3.795	3.780	3.820
El Paso, South Mainline	4.030	3.990	4.050
Northwest Sumas	3.765	3.740	3.780
Northwest Wyoming	3.765	3.740	3.840

Forward natural gas in $/mmBtu

Location	June	Jun 2013-Oct 2013	Nov 2013-Mar 2014
El Paso Permian	3.772	3.819	3.999
El Paso San Juan	3.730	3.786	4.018
Northwest, Wyoming	3.702	3.746	4.026
Northwest PL at Sumas	3.712	3.766	4.338
PG&E Citygates	4.023	4.084	4.340
SoCal Gas	3.902	3.964	4.211

Gas-implied, carbon-adjusted spark spreads

	NP-15		SP-15	
Marginal unit	Heat rate (mmBtu/MWh)	Carbon cost ($/MWh)	Heat rate (mmBtu/MWh)	Carbon cost ($/MWh)
Gas-implied	11.899	9.173	15.038	11.59
Carbon-adjusted	9.998	7.710	12.577	9.70
Western grid electric exports				6.21
Bonneville Power Administration exports				0.36
Powerex electric exports				0.42
Adjusted spark spreads in $/MWh				
Heat rate	7	8	10	12
NP-15				
Gas-implied	19.87	15.81	7.70	-0.41
Carbon-adjusted	14.47	9.64	-0.01	-9.66
Carbon cost	5.40	6.17	7.71	9.25
SP-15				
Gas-implied	31.67	27.73	19.85	11.97
Carbon-adjusted	26.27	21.56	12.14	2.72
Carbon cost	5.40	6.17	7.71	9.25

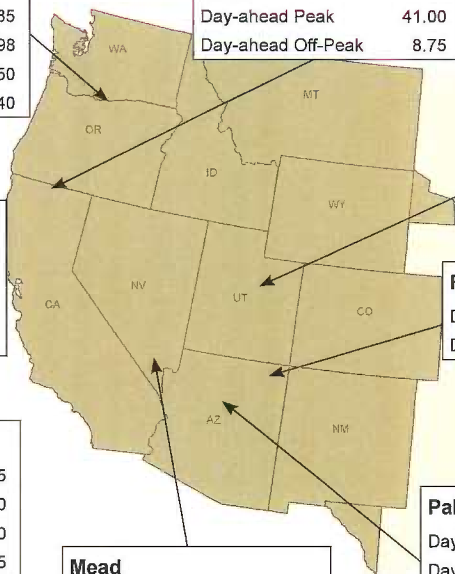
The data display the spread of fuel and carbon costs of running a power plant compared with the power price at NP-15 and SP-15, along with the carbon cost per heat-rate and for unspecified power imports. Data for SP-15 uses the day-ahead power price at SP-15 and the day-ahead gas price at SoCal. Data for NP-15 uses the day-ahead power price at NP-15 and the day-ahead gas price at PG&E Citygates. Both use the assessed December 2013-Delivery CCA price for carbon costs. For more information about this data, please contact airdaily@argusmedia.com or +1 (202) 775-0240.

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	COB	10,406	13.42	9.48	1.60	-6.28	-18.10	-29.92
	Four Corners	9,656	10.04	6.26	-1.30	-8.86	-20.20	-31.54
	Mead	11,485	17.67	13.73	5.85	-2.03	-13.85	-25.67
	Mid-C	10,332	12.53	8.77	1.25	-6.27	-17.55	-28.83
	Mona	9,103	7.97	4.18	-3.40	-10.98	-22.35	-33.72
	NP 15	11,899	19.87	15.81	7.70	-0.41	-12.58	-24.74
	Palo Verde	10,901	15.37	11.43	3.55	-4.33	-16.15	-27.97
	SP 15	15,038	31.67	27.73	19.85	11.97	0.15	-11.67
Off-peak	COB	2,221	-18.83	-22.77	-30.65	-38.53	-50.35	-62.17
	Four Corners	6,019	-3.71	-7.49	-15.05	-22.61	-33.95	-45.29
	Mead	7,043	0.17	-3.77	-11.65	-19.53	-31.35	-43.17
	Mid-C	527	-24.34	-28.10	-35.62	-43.14	-54.42	-65.70
	Mona	5,805	-4.53	-8.32	-15.90	-23.48	-34.85	-46.22
	NP 15	7,707	2.87	-1.19	-9.30	-17.41	-29.58	-41.74
	Palo Verde	6,579	-1.66	-5.60	-13.48	-21.36	-33.18	-45.00
	SP 15	8,756	6.92	2.98	-4.90	-12.78	-24.60	-36.42

West Prices at a Glance — $/MWh

Day-ahead markets for 13-May-13



Mid-Columbia

Day-ahead Peak	38.85
Day-ahead Off-Peak	1.98
Prompt Peak	32.50
Prompt Off-Peak	12.40

COB

Day-ahead Peak	41.00
Day-ahead Off-Peak	8.75

Mona

Day-ahead Peak	34.50
Day-ahead Off-Peak	22.00

NP-15

Day-ahead Peak	48.25
Day-ahead Off-Peak	31.25
Prompt Peak	42.60
Prompt Off-Peak	31.65

Four Corners

Day-ahead Peak	36.50
Day-ahead Off-Peak	22.75

SP-15

Day-ahead Peak	59.25
Day-ahead Off-Peak	34.50
Prompt Peak	48.50
Prompt Off-Peak	34.15

Mead

Day-ahead Peak	45.25
Day-ahead Off-Peak	27.75
Prompt Peak	41.50
Prompt Off-Peak	26.25

Palo Verde

Day-ahead Peak	42.95
Day-ahead Off-Peak	25.92
Prompt Peak	40.00
Prompt Off-Peak	25.15

Day-ahead minus hourly spread

10-May-13	Peak	Off-Peak
CAISO		
COB	-5.80	-5.05
Four Corners	9.62	11.87
Mead	15.35	12.10
Mona	29.95	10.53
NOB	24.37	0.04
NP-15	-1.27	20.00
Palo Verde	8.85	11.39
SP-15	6.66	21.91

Source: CAISO

Hourly price averages

	Peak		Off-peak	
	10-May-13	9-May-13	10-May-13	9-May-13
CAISO				
COB	41.30	37.06	8.47	22.72
Four Corners	21.88	38.55	9.13	24.12
Mead	20.75	38.92	9.15	24.27
Mona	1.05	39.28	9.22	14.32
NOB	19.16	37.63	6.23	20.46
NP-15	42.27	38.03	8.75	23.41
Palo Verde	22.17	38.37	8.45	24.04
SP-15	42.09	39.53	11.09	24.41

Source: CAISO

Emissions-adjusted dark spreads

	SO_2		24-hour average
	Peak	Off-peak	
COB	11.98	-20.27	1.23
Four Corners	21.11	7.36	16.53
Mead	16.23	-1.27	10.39
Mona	19.11	6.61	14.95
Mid-C	9.83	-27.04	-2.46
NP-15	19.23	2.23	13.56
Palo Verde	27.56	10.53	21.89
SP-15	30.23	5.48	21.98

Day-ahead peak spreads

	COB	Four Corners	Mead	Mona	Mid-C	NP-15	Palo Verde	SP-15
COB	—	4.50	-4.25	6.50	2.15	-7.25	-1.95	-18.25
Four Corners	-4.50	—	-8.75	2.00	-2.35	-11.75	-6.45	-22.75
Mead	4.25	8.75	—	10.75	6.40	-3.00	2.30	-14.00
Mona	-6.50	-2.00	-10.75	—	-4.35	-13.75	-8.45	-24.75
Mid-C	-2.15	2.35	-6.40	4.35	—	-9.40	-4.10	-20.40
NP-15	7.25	11.75	3.00	13.75	9.40	—	5.30	-11.00
Palo Verde	1.95	6.45	-2.30	8.45	4.10	-5.30	—	-16.30
SP-15	18.25	22.75	14.00	24.75	20.40	11.00	16.30	—

Source: Argus assessments

Impact of Renewables at a Glance

Northwest and California fundamentals: Changes are based on prior day

Real-time markets for 10-May-13

BC line loadings

	Average	Change
Peak (MW)	432	1,348
Off-peak (MW)	309	-23
Capacity utilization (percent)	19.5	44.5

BPA area

	Average	Change
Wind output		
Peak (MW)	2,405	1,901
Off-peak (MW)	1,751	-113
Hydroelectric output		
Peak (MW)	12,488	-164
Off-peak (MW)	11,641	-1,120

COI line loadings

	Average	Change
Peak (MW)	3,099	-36
Off-peak (MW)	3,163	-531
Capacity utilization (percent)	89.1	-0.6

PDCI line loadings

	Average	Change
Peak (MW)	2,901	161
Off-peak (MW)	2,920	3
Capacity utilization (percent)	97.2	3.6

COB

	Average	Change
Real-time peak ($/MWh)	34.05	-27.90
Real-time off-peak ($/MWh)	20.95	-16.02

NOB

	Average	Change
Real-time peak ($/MWh)	28.47	-30.10
Real-time off-peak ($/MWh)	15.03	-19.62

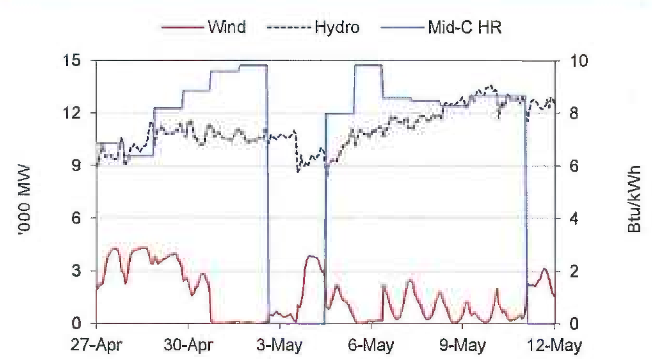
CAISO real-time ancillary services

	Average ($/MW)
Regulation down peak	0.26
Regulation down off-peak	0.34
Regulation up peak	1.00
Regulation up off-peak	2.03
Spinning reserve peak	0.00
Spinning reserve off-peak	0.00

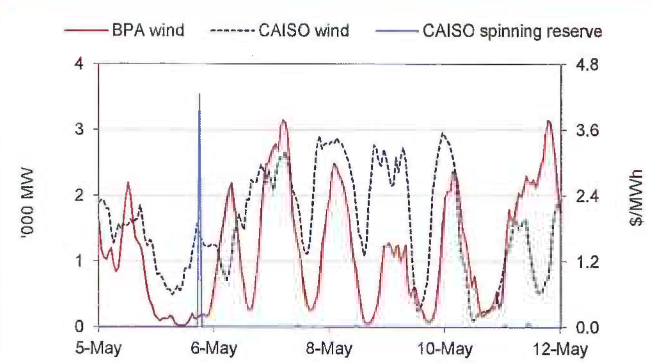
California

	Average	Change
Wind output		
Peak (MW)	1,378	950
Off-peak (MW)	1,950	82
Hydroelectric output		
Peak (MW)	2,823	-211
Off-peak (MW)	1,542	-58

BPA generation vs peak heat heat rates



Wind vs CAISO spinning reserve



Markets

Gas gains interest just under $4

US natural gas futures ended slightly higher today as low prices for the fuel spurred some buying, despite forecasts for mild weather in the coming weeks.

Nymex gas for June delivery rose by 1.5¢/mmBtu, or 0.4pc, to settle at $3.925/mmBtu. The 12-month strip was flat at $4.10/mmBtu while the 2014-calendar strip was marginally lower at $4.181/mmBtu. The prompt-month contract dropped to a low of $3.886/mmBtu earlier in the session and shed about 3pc last week amid signs that weather-related gas demand was moderating.

"The natural gas market has once again found buying interest in the $3.90/mmBtu area, aided by updated temperature forecasts that added back a bit of demand for the current week," Citi Futures Perspective analyst Tim Evans said today.

Meteorologists with the private forecasting firm Commodity Weather Group see hot weather across parts of California and the southwest this week and near-normal temperatures across most of the eastern US.

"For the most part, the pattern remains too quiet to generate large-scale demand concerns over the next two weeks," the forecasters said today.

US stockpiles have been lagging average levels this year thanks to a late-season bout of cold weather that buoyed gas demand in March and April.

Nymex natural gas settlements **$/mmBtu**

Contract	Price	Change	Volume*
Jun-13	3.925	0.015	100,440
Jul-13	3.971	0.011	44,774
Aug-13	3.993	0.010	21,364
Sep-13	3.992	0.010	14,776
Oct-13	4.012	0.008	27,409
Nov-13	4.086	0.002	13,207
Dec-13	4.252	-0.003	7,241
Jan-14	4.333	-0.009	17,647
Feb-14	4.312	-0.009	3,372
Mar-14	4.254	-0.006	6,231
Apr-14	4.034	-0.015	5,360
May-14	4.033	-0.015	700
Jun-14	4.069	-0.014	489
Jul-14	4.105	-0.013	203
Aug-14	4.126	-0.014	241
Sep-14	4.126	-0.013	308
Oct-14	4.147	-0.012	876
Nov-14	4.224	-0.012	215
Dec-14	4.405	-0.009	696

*Volume data estimated by Nymex, subject to verification.

Argus North American Electricity Methodology

Prices are based on daily survey data received from the non-commercial departments of market participants. Day-ahead peak and off-peak volume-weighted price indexes and assessments are compiled based on this data. Argus publishes the total volume of trades reported, the number of transactions, the high price, low price, and the volume weighted average price where sufficient data exists.

In low-liquidity markets when insufficient data is received to support a volume weighted index calculation (less than three trades of 25MW minimum each are received) a clearly marked price assessment is made. Volume and number of trades are left blank when an assessment is made.

Peak and off-peak electricity price indexes are based on data submitted daily to Argus voluntarily by the risk-management divisions or non-commercial departments of market participants.

All data submitted is treated confidentially and used only to establish the index or form a market price assessment. The Argus electricity index procedures are audited at least annually by the company's global compliance officer.

Only firm deals equal to or greater than 25MW are included in each index. Firm delivery means that a contract for liquidated damages in the event of non-performance is in place. Swaps, contracts for difference, and derivative-linked deals are not included but financially settled deals are included where the price does not diverge from what is observed in the physical market.

In low-liquidity markets, Argus publishes assessments based on an intelligent range of trade. Argus assesses the range within which electricity did or could have traded, based on actual deals and bids and offers throughout the trading day for next-day power, historical price relationships and other market conditions.

Assessments are clearly identifiable from volume-weighted average indexes. The volume and number of trades will be blank where an assessment is made.

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News

Northeast needs more transmission

The New England and New York Independent System Operators (ISOs) need to improve their transmission systems, according to participants at a regional energy summit.

"We have to consider more hydropower from Canada," Rhode Island governor Lincoln Chafee (Independent) told participants at a joint energy conference of the New England and New York grid operators in Boston on 10 May. "Climate change is real and we need more clean energy."

Chafee favors construction of the Northern Pass, a $1.2bn transmission line which would bring 1,200MW of power from Hydro Quebec into New England. Northeast Utilities is facing opposition from residents concerned about impacts to scenic views and forests. One of the most vocal opponents, the Society for the Protection of Northern Forests, has been trying to block the project by buying land in the path it expects the project to use.

Northeast Utilities has not yet finalized the route that the line would take but hopes to complete construction of the project in 2017.

Transmission is also an issue in New York, particularly as the state deals with uneven geographical distribution of generation.

"One-third of supply is downstate but two-thirds of demand is there," New York Power Authority (NYPA) chief executive Gil Quiniones said. "Congestion points need to be fixed."

Making things worse is the fact that some of the generation units in southern New York are located on the coast and vulnerable to hurricanes like last year's Sandy, which took out some power plants and damaged transmission.

Quiniones and New York ISO president Stephen Whitley support the so-called New York Energy Highway, an initiative to improve the state's electric grid with an estimated $5.7bn in public and private investment to build up to 3,200MW of generation and transmission over the next decade.

Anti-San Onofre group gets hearing

An independent nuclear board has decided that Southern California Edison's efforts to restart Unit 2 at the San Onofre nuclear plant constitute a license amendment proceeding during which a public interest group can be heard.

The Atomic Licensing Safety Board, a three-judge panel independent of the Nuclear Regulatory Commission that conducts adjudicatory hearings on licensing issues, will allow Friends of the Earth to address a utility plan to allow the reactor to restart.

Southern California Edison wants to run the unit at 70pc of thermal power until its next refueling outage. Friends of the Earth wants the plant shut down permanently and asked for a hearing last year

The two nuclear two units at the plant on the Pacific Ocean have been shut down for nearly 1 1/2 years after steam generator tubes of a recent vintage were found to have leaked at the 1,080MW Unit 3. Subsequent inspections found significant degradation of the tubes at the 1,070MW Unit 2.

The loss of the units from the state's power grid has raised power and gas prices, boosted spark spreads and allowed inefficient, old plants to be restarted to serve load. A drought in California and the wider west that has reduced reservoir levels is expected to make hydroelectricity scarce this summer, raising power prices even more. Friends of the Earth has argued to California regulators that a restart of Unit 2 would cost more than buying power in the short-dated market.

The licensing board said its decision only applies to San Onofre and not to other cases in which its approval is sought.

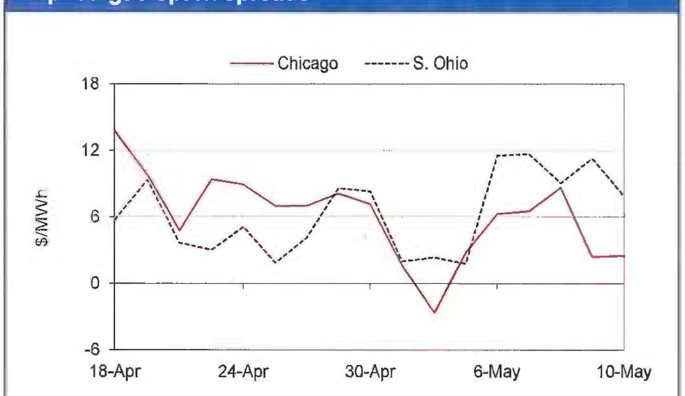
Southern sees gains in gas capacity

Capacity growth for more efficient US natural gas-fired power plants will be modest in the next decade, which could limit the amount of additional market share that gas can take from coal, an executive with a leading US utility said.

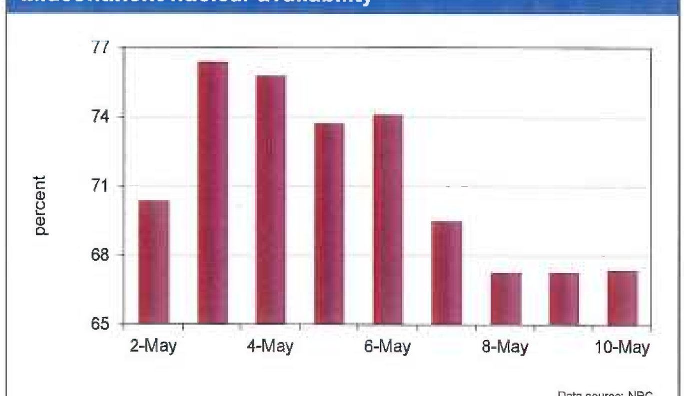
Increased supply and cheap prices helped gas' share of US electricity generation grow to 30pc last year from 21pc in 2008, while coal's share shrank to 38pc from 48pc four years earlier.

But combined-cycle gas capacity will increase by only 5pc between now and 2020 to just over 200 GW, Southern Co. director of coal services Rob Hardman said at the Eastern Fuel Buyers

Implied gas spark spreads



Midcontinent nuclear availability



News

Conference in Orlando, Florida last week. One gigawatt of combined-cycle gas generation would displace about 2.5mn short tons/yr (2.3mn metric tonnes/yr) of coal demand.

While gas, nuclear and other sources must be part of the country's generation portfolio, an "all-the-above" strategy including coal will be "critical for America's long-term energy security," Hardman said. He highlighted the risks of full reliance on gas for power generation, including counterparty credit risk and the potential for increased domestic demand and LNG exports to lift prices and increase market volatility.

Minnesota solar bill in face-off

A bill to create a solar energy standard in Minnesota moved to a conference committee on 10 May after the Senate clashed with the House of Representatives on the size of the compliance requirements.

The version of House File 956 that passed the House of Representatives on a 70-63 vote on 7 May would set a solar standard of 4pc of the state's retail electricity sales by 2025 with interim obligations of 0.5pc by 2016 and 2pc by 2020.

But the Senate altered the proposed standard to 1pc before passing the bill 37-26 on 10 May. A conference committee of three senators and three representatives planned to meet today in search of a compromise.

Xcel estimates the 4pc standard would cost $1bn by 2025, while the 1pc mandate would cost less than one-quarter that amount because it has no incremental requirements and would enable the company to take advantage of future declines in solar installation costs.

The conference committee would probably dispose of a provision in the House bill requiring Xcel to spend 1.33pc of its retail sales revenue on rooftop solar incentives at a cost of about $40mn/yr, sources said.

Both bills would allow community aggregation for solar projects, meaning multiple customers could subscribe for power from a single net-metered system. And both would also expand the project size eligible for net metering by Xcel Energy customers from 40kW to 1MW and create incentives for in-state solar panel manufacturing.

The House bill would also increase Xcel's overall renewable portfolio standard obligation to 40pc by 2030. Xcel is the largest public utility in the state, and has a 30pc by 2020 renewables obligation, smaller than the 25pc by 2025 compliance obligation for electric cooperatives and municipal utilities.

Lawyers downplay California lawsuits

Legal experts doubt that groups suing the California Air Resources Board (ARB) for holding carbon allowance auctions can prove the agency went beyond its authority to sell the emissions permits.

ARB faces two lawsuits against its use of auctions to distribute the majority of carbon allowances under its cap-and-trade program. The first lawsuit, brought by the California Chamber of Commerce, was filed one day before ARB held its 16 February auction. The second was filed last month by a group of businesses represented by the Pacific Legal Foundation.

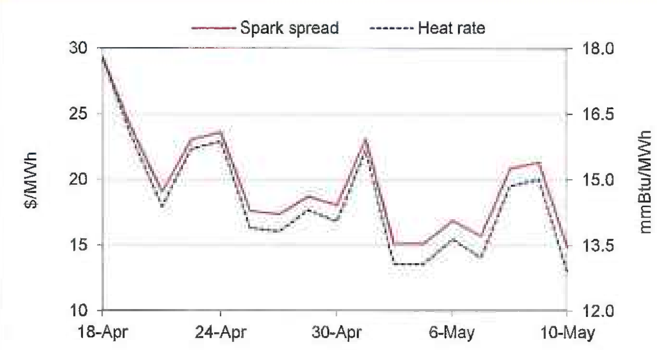
Both suits argue ARB went beyond its authority by holding its quarterly allowance auctions and that the auctions constitute an illegal tax. The Pacific Legal Foundation claims ARB cannot disguise the auctions as a fee.

Sean Hecht, executive director of the environmental law center at UCLA School of Law in Los Angeles, said it is difficult to argue the auctions constitute either a tax or a fee. "The auctions fit poorly into either category," said Hecht, speaking at a Law Seminars International cap-and- trade seminar in San Francisco last week.

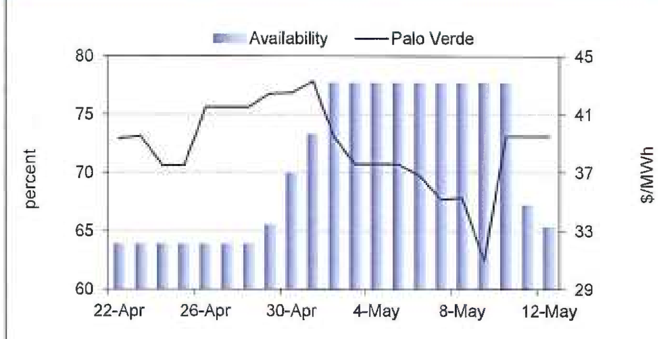
"My gut feeling is if ARB does a good job of explaining the program and the judge understands this is not a fee or a tax, the plaintiffs are unlikely to win" Hecht said.

The plaintiffs argue that the cap-and-trade auctions are an illegal tax because the California constitution requires a two-thirds majority of the legislature to approve a new tax, and AB

Carbon-adjusted coal generation: PJM W



West nuclear availability vs Palo Verde



Nuclear availability data source: NRC

News

32, California's climate law, was passed with a simple majority. The California Chamber of Commerce asserts AB 32 does not authorize ARB to impose fees other than those needed to cover the administrative costs of running the program.

The chamber also argues that California is holding auctions outside of its authority because AB 32 did not specifically direct the agency to hold auctions or define how allowance revenues were to be collected and distributed.

Michael Romey, partner at law firm Latham & Watkins, said it may be difficult for plaintiffs to claim ARB acted beyond its authority because of the outcome of a previous court case known as *Association of Irritated Residents et al v. ARB*. The judge in that case found ARB has broad authority to implement AB 32 as it sees fit. Romey said the previous case could weigh against the plaintiffs' arguments that ARB does not have the power to hold auctions.

He added that ARB should argue that allowances sold at auction constitute a public resource that provide holders the the right to emit greenhouse gases. "This argument would probably be well heard," Romey said.

Attachment 42.1

13.17 Gains or Losses on Disposal of Assets

315. AUC Rule 026, section 6(2)(i), states in part:

> Utilities shall maintain the Existing Accounting Practice of recording gains and losses upon retirement or disposal of assets. Utilities shall identify and record any difference in accounting between the IFRS reporting requirements and these regulatory reporting requirements in a separate subsidiary accumulated depreciation account.

316. In accordance with this section, FAI proposed a separate account within accumulated depreciation to track these items and will incorporate these amounts in the next depreciation study. FAI indicated no gains or losses are forecast for the test period.

317. The UCA supported a deferral account for gains and losses on disposal relation to property, plant and equipment.

13.17.1 Commission Findings

318. The proposed treatment is consistent with IFRS and AUC Rule 026. Therefore the Commission approves the deferral account for gains and losses on disposal of assets.

13.18 Overhead Costs Expensed Under IFRS but Eligible for Capitalization under GAAP Capitalized

319. Costs that are not 'directly attributable' to an asset are not allowed to be capitalized under IFRS.[218] Under Rule 026 paragraph 6(2)(b), FAI proposed a capitalized overhead deferral account to defer the amount that would have been capitalized in property, plant and equipment under Canadian GAAP and to amortize the account at a composite rate reflective of that utilized by the asset classes under which it would previously have been capitalized. FAI stated that capitalized overhead has always been deferred to future periods through various asset classes in property, plant and equipment. In compliance with IFRS, it is now proposed to be deferred to future periods in a separate asset class.

320. The UCA supported a deferral account for capitalized overhead.

13.18.1 Commission Findings

321. The Commission notes the support of the UCA and approves FAI's proposed capitalized overhead deferral as it is consistent with AUC Rule 026.

13.19 IFRS Transitional Exemptions

322. FAI indicated that, should any differences arise in the January 1, 2010 capital asset balance under IFRS and the historic cost amounts utilized for rate setting, FAI would continue to utilize the historic cost amount for rate-setting purposes with the difference being amortized through regulatory depreciation expense. FAI did not forecast any such amounts. However, to the extent there were any, FAI proposed deferral treatment. A recommendation for settlement would be included in subsequent applications.

323. The UCA supported the use of a deferral account for IFRS Transitional Exemptions.

[218] Rule 026, Footnote 6.

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Ontario

VIA EMAIL AND WEB POSTING

July 17, 2012

TO: Licensed Electricity Distributors
All Other Interested Parties

RE: Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013

This letter serves to provide the Board's regulatory accounting policy direction to electricity distributors on matters arising from the one-year deferral option for the IFRS changeover in 2012. The Board will permit electricity distributors electing to remain on Canadian GAAP ("CGAAP") in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012. The Board however will require that these changes be mandatory in 2013 for all distributors that have not yet made these changes, even if there is a further option to defer IFRS changeover in 2013. A new variance account is created and authorized for distributors to record the financial differences arising from these accounting changes.

Background

The Canadian Accounting Standards Board ("AcSB") announced in March 2012 that it would allow rate-regulated entities a one-year deferral option for the IFRS changeover in 2012. In light of the AcSB's announcement, the Board issued a letter to electricity distributors on April 30, 2012 and provided direction regarding this deferral option. The letter indicated, among other things, that,

- The Board will not require regulatory accounting and reporting for 2012 to be in modified IFRS ("MIFRS") if a distributor is not required to adopt IFRS for financial reporting and opts to remain on CGAAP.
- For those distributors that have transitioned to IFRS or whose rates are set based on MIFRS, the Board expects these distributors to conduct regulatory accounting and reporting for 2012 in MIFRS.

The Board has received numerous inquiries for regulatory accounting direction from distributors requesting to make changes to their depreciation rates (for example, using the *Depreciation Study for Use by Electricity Distributors* (EB-2010-0178), (the "Kinectrics Report") or own depreciation study) and capitalization policies while still under CGAAP in 2012. Several distributors indicated that they have already completed sufficient detailed accounting work in these areas in their transition to IFRS, and as such, they are positioned and wish to make these accounting changes while still under CGAAP in 2012. They are seeking accounting direction on whether the Board will allow these accounting changes, and if so, what would be the approval process.

Regulatory accounting policy direction regarding Changes to the Depreciation Expense and Capitalization Policies

A key benefit that was expected to be derived from the Board's established accounting policies under the IFRS accounting framework ("modified IFRS") was that the changes to the depreciation expense and capitalization policies would be applied uniformly and in the same timeframe by all distributors (with a few exceptions, for example, distributors adopting US GAAP).

There were several distributors that have adopted these and other accounting changes for regulatory purposes including ratemaking in their 2012 cost of service applications which were approved by the Board. The same approach is expected from distributors filing 2013 cost of service rate applications, which are required to be filed on an MIFRS basis. The Board encourages and will permit distributors that have deferred the changeover to IFRS in 2012 to also implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012. The Board however will require that these changes be mandatory in 2013 (i.e., effective on January 1, 2013) for those distributors that do not elect to make these accounting changes in 2012 regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS. These accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* ("APH").

The Board will not require distributors to seek Board approval in order to make these accounting changes that otherwise would have been required as specified in the "CGAAP-based" APH (dated July 2007), which is applicable and in force for these distributors still under CGAAP. These accounting changes for adherence to Board requirements for MIFRS and their associated rate impacts will be reviewed as part of a distributor's next cost of service application.

Account 1576 and Accounting Requirements

The Board has approved a new variance Account 1576, Accounting Changes Under CGAAP, for distributors to record the financial differences arising as a result of the election to make these accounting changes under CGAAP in 2012 or to make these changes as mandated by the Board in 2013, if applicable.

The account description of Account 1576 and the associated accounting requirements, including an illustrative example, are provided in the July 2012 *Accounting Procedures Handbook – Frequently Asked Questions* (see question and answer #2) posted on the Board's website at www.ontarioenergyboard.ca.

Distributors are expected to reflect these accounting changes in their CGAAP-based financial statements since rate-regulated accounting is recognized in CGAAP.

Any questions regarding the above should be directed to the Market Operations Hotline at 416-440-7604 or by e-mail at market.operations@ontarioenergyboard.ca. The Board's toll free number is 1-888-632-6273.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

AND UPON noting that expenditures on distribution lines are necessary to continue with the replacement of aged distribution lines, which are reaching the end of their suggested life span, and on customer-driven line extensions and highway alterations;

AND UPON reviewing expenditures on corporate services and noting the required information technology and related expenditure plans appear reasonable;

NOW THEREFORE, pursuant to the *Electric Power Act*,

IT IS ORDERED THAT

1. The capital budget application of the Company, with the exception of the proposed expenditures on the third cable preparatory work for which Commission direction is still under consideration, filed herein on June 29, 2012 and summarized below is approved; and

2013 Capital Budget Summary	
Corporate	$1,048,000
Generation	1,397,000
Distribution	18,540,000
Transmission	3,417,000
General Expense Capitalized	441,000
Interest During Construction	147,000
Total	$ 24,990,000
Less: Contributions	(275,000)
Total (Net)	$ 24,715,000

2. Capital budget variances reported to the Commission for capital expenditures made in 2011 are approved.

<u>IT IS THEREFORE ORDERED THAT:</u>

1. The accounting policy to be applied for the purpose of capitalization of general expenses, will be the incremental basis which will result in the Applicant's allocations to capital assets of only those costs which are incremental costs of capital projects.

2. Overhead costs will be considered to be incremental costs of capital projects to the extent they vary with the level of construction as compared to no capital projects whatsoever. Otherwise the overhead costs are expenses of the period in which they are incurred.

3. The guideline for capitalization of general expenses are set out on pages16 - 22 of this Order. The Applicant will follow these guidelines to the extent practicable.

4. General Expenses Capitalized will be allocated to hydro assets, diesel assets, substations, transmission, general property, transportation, communication, computer and software assets, and distribution assets through a flat rate.

5. The change in accounting policy for general expenses capitalized to the incremental basis, from the full cost method, will be phased in over the period January 1, 1995 to December 31, 1999. In 1995, GEC will be the incremental

5. (con't)

amount plus an adjustment of 80% of the difference between full cost and incremental amounts. Each year thereafter, the adjustment will be reduced by 20% until 1999 when only incremental costs will be allocated. The Applicant may determine which specific general expense costs are adjusted during the period of transition, providing the total impact arrives at the phase-in schedule described above. With respect to allocation to specific capital assets during the period of transition, the Applicant shall allocate the reduction in GEC to distribution assets first.

6. Additional pension funding toward the Applicant's Unfunded Pension Liability is approved up to a limit of $12 million in 1995 and $6 million in 1996. The Applicant shall file an affidavit with the Board subsequent to each years funding indicating the actual additional amounts contributed together with a revised net present value analysis reflecting the actual additional contribution.

7. The Applicant shall file annually with the Board a report tracking the results of the early retirement program.

8. The Applicant shall pay the expenses of the Board arising out of this hearing.

Attachment 45.1

2007 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE
AS AT DECEMBER 31, 2007

	Acct.		Reference	Actual 2006	Decision 2007 (1)	Actual 2007	Change from Decision
					($000s)		
1	101	Plant in Service, January 1	p. 3	820,437	933,467	943,920	10,453
2		Net Additions	p. 6	107,875	119,835	118,150	(1,685)
3		Plant in Service, December 31		928,312	1,053,302	1,062,070	8,768
4	Add:						
5	107	*CWIP (not subject to AFUDC)	p. 7	33,208	5,578	13,112	7,534
6	105	Plant Held for Future Use		-		-	-
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 10	18,311	20,444	14,473	(5,971)
				991,743	1,091,236	1,101,567	10,331
9	Less:						
10		Accumulated Depreciation	p. 11	219,975	239,071	250,323	11,252
11		and Amortization					
12	252	Contributions in Aid of Construction		66,132	69,520	78,351	8,831
13				286,107	308,591	328,674	20,083
14		Depreciated Rate Base		705,636	782,645	772,893	(9,752)
15		Prior Year Depreciated Rate Base		631,231	685,737	712,911	27,174
16		Mean Depreciated Rate Base		668,434	734,191	742,902	8,711
17	Add:	Allowance for Working Capital	p. 12	7,511	6,653	6,519	(134)
18		Adjustment for Capital Additions	p. 13	(4,806)	(814)	(2,878)	(2,064)
19		FBC Mid Year Utility Rate Base		671,138	740,030	746,543	6,513
20		PLP Mid Year Utility Rate Base			7,190	-	(7,190)
21		Mid Year Utility Rate Base		671,138	747,220	746,543	(676)

(1) In the financial schedules in this Annual Report, the "2007 Decision" tables reflect the cumulative impact of three Orders. These are:

- G-159-06 approved the windup of Princeton Light and Power Company, Ltd. (PLP) effective December 31, 2006, and the transfer of PLP assets to FortisBC, effective January 1, 2007.
- G-162-06 approved FortisBC's 2007 Revenue Requirement Application. Tab 9 of the Application included forecast 2007 financial schedules for the reorganized FortisBC, which included PLP.
- G-20-07 instructed FortisBC to remove Construction Work in Progress subject to AFUDC from rate base and to remove AFUDC from Revenue Requirements effective January 1, 2007.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2007

Line	Account		December 31 2006	December 31 2006 PLP	January 1 2007	Additions	Retirements	December 31 2007
		Hydraulic Production Plants 1,2, 3, & 4			(000s)			
1	330	Land Rights	120		120	727	-	847
2	331	Structures and Improvements	10,337		10,337	621	(11)	10,947
3	332	Reservoirs, Dams & Waterways	17,320		17,320	2,189	(76)	19,433
4	333	Water Wheels, Turbines and Gen.	47,064		47,064	7,806	(367)	54,503
5	334	Accessory Equipment	19,731		19,731	2,773	(133)	22,370
6	335	Other Power Plant Equipment	37,624		37,624	684	(31)	38,277
7	336	Roads, Railroads and Bridges	1,053		1,053	-	-	1,053
8			133,249	-	133,249	14,799	(617)	147,430
9		Transmission Plant						
10	350.1	Land Rights-R/W	7,079		7,079	-	-	7,079
11	350.1	Land Rights-Clearing	4,364		4,364	132		4,496
12	353	Station Equipment	116,253		116,253	19,201	(76)	135,378
13	355	Poles Towers & Fixtures	57,001		57,001	8,143	(2)	65,142
14	356	Conductors and Devices	57,025		57,025	5,575	-	62,601
15	359	Roads and Trails	817		817	-	-	817
16			242,539	-	242,539	33,051	(78)	275,513
17		Distribution Plant						
18	360.1	Land Rights-R/W	1,449	79	1,528	208	-	1,736
19	360.1	Land Rights-Clearing	3,500	653	4,153	1,703		5,856
20	362	Station Equipment	103,355	296	103,651	11,877	(233)	115,295
21	364	Poles Towers & Fixtures	91,442	4,447	95,889	9,788	(285)	105,392
22	365	Conductors and Devices	155,732	3,718	159,450	16,964	(429)	175,985
23	368	Line Transformers	69,595	2,052	71,647	13,078	(1,026)	83,699
24	369	Services	6,090	1,202	7,292	-	-	7,292
25	370	Meters	11,271	715	11,986	1,023	(255)	12,754
26	371	Installation on Customers' Premises	938	-	938	-	-	938
27	373	Street Lighting and Signal System	5,545	146	5,691	1,679	(53)	7,318
28			448,917	13,308	462,225	56,320	(2,281)	516,264
29		General Plant						
30	389	Land	3,519		3,519	2,281	-	5,800
31	390	Structures-Frame & Iron	337		337		-	337
32	390.1	Structures-Masonry	20,242	802	21,044	1,922	-	22,966
33	391	Office Furniture & Equipment	4,932	54	4,986	247	-	5,233
34	391.1	Computer Equipment	39,715	206	39,921	2,707	(449)	42,179
35	392	Transportation Equipment	11,730	935	12,665	4,431	(649)	16,447
36	394	Tools and Work Equipment	8,645	303	8,948	936	-	9,884
37	397	Communication Structures and Equipment	14,487		14,487	5,529		20,016
38			103,607	2,300	105,907	18,054	(1,098)	122,863
39								
40	101	Plant in Service	928,312	15,608	943,920	122,224	(4,074)	1,062,070
41	107.1	Plant under construction not subject						
42		to AFUDC	7,381		7,381			13,112
43	107.2	Plant under construction						
44		subject to AFUDC	25,827		25,827			44,956
45	114	Utility Plant Acquisition Adjustment	11,912		11,912			11,912
46	105	Plant held for future use	-		-			-
47								
48	105	Utility Plant per Balance Sheet	973,432		989,040			1,132,050

Note: Differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2007

		Balance at Dec. 31, 2006	PLP Balance at Dec. 31, 2006	Balance at Jan. 1, 2007	Additions and Transfers ($000s)	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2007
	Energy Management							
1	Energy Management Additions	17,882		17,882	2,464		(1,220)	19,126
2	Tax Impact	(12,064)		(12,064)	(841)			(12,905)
3	PLP Energy Management		190	190			(77)	113
4		5,818	190	6,008	1,623	-	(1,297)	6,334
5	**Deferred Regulatory Expense**							
6	Deferred Revenue - Incentive Adjustment	(2,523)		(2,523)	(1,132)	2,523		(1,132)
7	Provision for True-up for 2006 Incentive	34		34		(13)		21
8	2005 Revenue Requirements	529		529			(176)	353
9	Tax Impact	(152)		(152)	-		51	(101)
10	2006 Revenue Requirements	160		160	1		(53)	107
11	Tax Impact	(53)		(53)	-		18	(35)
12	2007 Revenue Requirements	29		29	7		-	36
13	Tax Impact	(9)		(9)	(2)		-	(11)
14	2007 BC Hydro Rate Design			-	11		-	11
15	Tax Impact			-	(4)		-	(4)
16	2008 Revenue Requirements	-		-	32		-	32
17	Tax Impact	-		-	(11)		-	(11)
18	Terasen Gas ROE Application	(3)		(3)	-		3	0
19	Tax Impact	6		6			(6)	-
20		(1,982)	-	(1,983)	(1,099)	2,510	(164)	(735)
21								
22	**Preliminary and Investigative Charges**	1,814		1,814	(1,496)		-	321
23								
24	**Other Deferred Charges and Credits**							
25	Trail Office Lease Costs	203		203			(12)	191
26	Trail Office Rental to SD#20	(564)		(564)		(33)	-	(598)
27	Prepaid Pension Costs	5,732		5,732	926			6,657
28	Tax Impact	(164)		(164)	(316)			(480)
29	Post Retirement Benefits	(1,329)		(1,329)	(2,199)			(3,529)
30	Tax Impact	441		441	750			1,191
31	Renegotiation of Canal Plant Agreement	412		412			(412)	-
32	Tax Impact	(59)		(59)	-		59	-
33	20 Year Transmission System Plan	494		494	-		(165)	329
34	Tax Impact	(25)		(25)	-		9	(16)
35	2008 System Development Plan Update			-	248			248
36	Tax Impact			-	(84)			(84)
37	2008 COSA & rate design application				44			44
38	Tax Impact				(15)			(15)
39	Automated Meter Reading Feasibility Study			-	68			68
40	Tax Impact			-	(23)			(23)
41	Resource Plan Study	91		91	-		(30)	61
42	Tax Impact	(10)		(10)	-		3	(7)
43	2007 Resource Plan Study			-	217			217
44	Tax Impact			-	(74)			(74)
45	Hydro Electric Supply Study	21		21	(21)			-
46	Tax Impact	(7)		(7)	7			-
47	Renew BCH Power Purchase Agreement	3		3	1			4
48	Tax Impact	(1)		(1)	-			(1)
49	Discount Forfeit Defense — Excl. from 2007 rate base	164		164	34	(198)		-
50	Tax Impact — pursuant to G-162-06	(54)		(54)	(12)	66		-
51	Revenue Protection	590		590	176		(590)	176
52	Tax Impact	(193)		(193)	(60)		194	(61)
53	Big White Supply Project	3,342		3,342		(3,342)	-	-
54	Tax Impact	-		-	-		-	-
55	Innovative Clean Energy Fund Levy Implementation			-	23			23
56	Tax Impact			-	(8)			(8)
57	PLP Transition costs	74		74		(74)		-
58	Tax impact	(24)		(24)		24		-
59	PLP Potential Substation		36	36			(11)	25
60	PLP Settlement Costs		63	63			(16)	47
61	PLP Computer Software		132	132			(23)	109
62	PLP Deferred Pension Credit		(93)	(93)			12	(81)
63	PLP Deferred Rate Stabilization Account		(75)	(75)				(75)
64		9,137	62	9,199	(318)	(3,557)	(981)	4,337
65	**Deferred Debt Issue Costs**							
66	Series E	10		10			(3)	7
67	Series F	142		142			(13)	129
68	Series G	127		127			(9)	118
69	Series H	121		121			(14)	106
70	Series I	213		213			(14)	199
71	Series J	196		196			(65)	131
72	Series 04-1	1,717		1,717			(215)	1,501
73	Tax Impact	(36)		(36)	(19)		4	(51)
74	Series 05-1	1,199		1,199			(42)	1,156
75	Tax Impact	(166)		(166)	(78)		6	(238)
76	Series 07-1			-	1,241			1,241
77	Tax Impact				(85)			(85)
78		3,524	-	3,524	1,059	-	(364)	4,216
79								
80								
81								
82	TOTAL DEFERRED CHARGES	18,311	252	18,563	(230)	(1,047)	(2,807)	14,473

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Attachment 45.1

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2007

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2006	Acc. Prov. For PLP Dec. 31, 2006	Acc. Prov. For Depreciation Jan. 1, 2007	Deprec. Rate	Asset Balance Jan. 1, 2007	Depreciation Expense Dec. 31, 2007	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2007
			(000s)					(000s)		
1		Hydraulic Production Plant								
2	330	Land Rights	3		3	2.6%	120	3	(473)	(467)
3	331	Structures and Improvements	4,420		4,420	1.2%	10,337	169	(18)	4,571
4	332	Reservoirs, Dams and Waterways	2,741		2,741	1.7%	17,320	294	(224)	2,812
5	333	Water Wheels, Turbines & Generators	2,962		2,962	2.2%	47,064	1,035	(718)	3,279
6	334	Accessory Electrical Equipment	7,019		7,019	2.4%	19,731	474	(240)	7,253
7	335	Other Power Plant Equipment	5,527		5,527	2.3%	37,624	865	(53)	6,338
8	336	Roads, Railroads, and Bridges	186		186	1.4%	1,053	15	-	201
9			22,858	-	22,858	2.1%	133,249	2,855	(1,726)	23,987
10		Transmission Plant								
11	350.1	Land Rights -R/W	(72)		(72)	0.0%	7,079	-	-	(72)
12	350.1	Land Rights - Clearing	881		881	1.6%	4,364	70	-	951
13	353	Station Equipment	19,359		19,359	3.0%	116,253	3,488	(412)	22,435
14	355	Poles Towers & Fixtures	12,610		12,610	3.0%	57,001	1,710	(230)	14,089
15	356	Conductors and Devices	9,051		9,051	3.0%	57,025	1,711	(207)	10,555
16	359	Roads and Trails	(15)		(15)	2.9%	817	24	-	9
17			41,814	-	41,814	2.9%	242,539	7,003	(850)	47,967
18		Distribution Plant								
19	360.1	Land Rights -R/W	-			0.0%	1,528	-	-	-
20	360.1	Land Rights - Clearing	192		192	2.1%	4,153	87	-	279
21	362	Station Equipment	23,836	129	23,965	3.0%	103,651	3,110	(510)	26,565
22	364	Poles Towers & Fixtures	25,333	2,453	27,786	3.0%	95,889	2,877	(475)	30,187
23	365	Conductors and Devices	37,221	1,205	38,426	3.0%	159,450	4,784	(717)	42,493
24	368	Line Transformers	15,502	571	16,073	2.9%	71,647	2,078	(1,453)	16,698
25	369	Services	6,090	277	6,367	0.0%	7,292	36	-	6,403
26	370	Meters	3,740	328	4,068	3.5%	11,986	420	57	4,545
27	371	Installation on Customers' Premises	985		985	0.0%	938	-	-	985
28	373	Street Lighting and Signal Systems	1,285	130	1,415	2.4%	5,691	137	(81)	1,471
29			114,185	5,093	119,278	2.9%	462,225	13,529	(3,179)	129,628
30		General Plant								
31	389	Land	(11)		(11)	0.0%	3,519	-	-	(11)
32	390	Structures - Frame & Iron	259	266	525	0.8%	337	3	-	528
33	390.1	Structures - Masonry	2,437	32	2,469	3.0%	21,044	506	(255)	2,474
34	391	Office Furniture & Equipment	2,603	178	2,781	7.5%	4,986	374	-	3,155
35	391.1	Computer Equipment	21,273	757	22,030	10.6%	39,921	4,232	(450)	25,810
36	392	Transportation Equipment	4,386	206	4,592	0.4%	12,665	51	(607)	4,036
37	394	Tools and Work Equipment	3,818		3,818	9.5%	8,948	850	-	4,668
38	397	Communication Structures and Equip	3,919		3,919	6.0%	14,487	869	(7)	4,781
39			38,684	1,439	40,123	6.5%	105,907	6,885	(1,318)	45,442
40										
41	108	Total Accumulated Depreciation	217,541	6,532	224,073	3.2%	943,920	30,272	(7,073)	247,024
42										
43		Deduct - Portion of CIAC Depreciated						(2,912)		
44										
45	403	Depreciation Expense						27,360		
46										
47		Other								
48	114	Utility Plant Acquisition Adjustment	4,281				11,912	186		4,466
49	390	Leasehold Improvements	951				2,568	286		1,238
50		Rate Stabilization Adjustment	(2,798)			10.0%		311		(2,487)
		Manual entry for buy out of lease								82
51		Total Accumulated Depreciation	2,434					783		3,299
52										
53	108	Accumulated Depreciation per								
54		Balance Sheet	219,975					28,143		250,323

Note: Differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2006	Decision (1) 2007	Actual 2007 ($000s)	Normalized 2007	Change from Decision
1	SALES VOLUME (GW.h)	3,054	3,077	3,090	3,084	7
2	ELECTRICITY SALES REVENUE	204,252	207,368	209,651	209,232	1,864
3	EXPENSES					
4	Power Purchases	68,002	69,260	66,629	66,615	(2,645)
5	Wheeling	3,840	3,466	3,471	3,471	5
6		71,842	72,726	70,100	70,086	(2,640)
7	Operating Expenses					
8	Labour and Benefits	21,317	22,380	21,646	21,646	(734)
9	Materials	6,011	7,020	6,736	6,736	(284)
10	Other O&M Expenses					
11	Uncollectable Accounts	767	487	1,002	1,002	515
12	Insurance	783	948	944	944	(4)
13	Rental of Trail and Kelowna Offices	956	1,032	1,119	1,119	87
14	Rental of Facilities	2,503	2,607	2,718	2,718	111
15		32,337	34,474	34,165	34,165	(309)
16	Taxes					
17	Property and Capital Tax	10,275	10,926	10,642	10,642	(284)
18	Water Fees	8,371	7,976	7,918	7,918	(58)
19		18,646	18,902	18,560	18,560	(342)
20	Depreciation and Amortization	26,746	30,565	30,949	30,949	384
21	Other Income	(5,153)	(4,689)	(5,504)	(5,504)	(815)
22	AFUDC	(2,360)	-	-	-	-
23	Incentive Adjustments	2,431	(2,523)	(1,391)	(1,391)	1,132
24	UTILITY INCOME BEFORE TAX	59,763	57,912	62,771	62,366	4,454
25	Less:					
26	INCOME TAXES	6,663	3,332	5,898	5,760	2,428
27	FORTISBC EARNED RETURN	53,100	54,580	56,873	56,606	2,026
28	Add: PLP EARNED RETURN		499			(499)
29	TOTAL EARNED RETURN	53,100	55,079	56,873	56,606	1,527
30	RETURN ON RATE BASE					
31	Utility Rate Base	671,138	747,220	746,543	746,543	(677)
32	Return on Rate Base	7.91%	7.37%	7.62%	7.58%	0.21%

(1) Commission Orders G-159-06, G-162-06, G-20-07

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2007

	Acct.		2007	2006	Change
1		GENERATION			
2	535R	Supervision & Administration	586	370	216
3	536	Water Fees	7,918	8,371	(453)
4	542	Structures	552	653	(101)
5	543	Dams & Waterways	203	239	(36)
6	544	Electric Plant	352	272	80
7	545	Other Plant	235	595	(360)
8			9,846	10,499	(653)
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	66,629	67,576	(947)
12	556	System Control	960	713	247
13			67,589	68,289	(700)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,171	1,149	22
17	560R-2	System Planning	948	1,004	(56)
18	561	Load Dispatching	1,272	945	327
19	562	Transmission Station Expense	623	668	(45)
20	563R-1	Transmission Line Maintenance	171	89	82
21	563R-2	Transmission ROW Maintenance	650	654	(4)
22	565	Wheeling	3,471	3,840	(369)
23	567	Rents	3,268	2,503	765
24					0
25	583R-1	Distribution Line Maintenance	2,545	2,254	291
26	583R-2	Distribution ROW Maintenance	1,516	1,595	(79)
27	586	Meter Expenses	1,027	906	121
28	587	Customer Installations	0	0	0
29	592	Distribution Station Expense	1,112	832	280
30	596	Street Lighting	70	66	4
31	598	Other Plant	255	195	60
32			18,099	16,698	1,401
33					
34		CUSTOMER SERVICE			
35	901	Supervision & Administration	855	826	29
36	902	Meter Reading	1,841	1,702	139
37	903	Customer Billing	597	408	189
38	904	Credit & Collections	1,002	1,427	(425)
39	910	Customer Assistance	1,940	1,867	73
40	911	Energy Management Promotion	0	0	0
41			6,235	6,230	5

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2007

	Acct.		2007	2006	Change
42					
43		ADMINISTRATIVE AND GENERAL			
44	920	Salaries			
45	920.1	Executive & Senior Management	1,234	1,104	130
46	920.2	Legal	336	316	20
47	920.3	Human Resources	390	350	40
48	920.4	Finance & Accounting	503	523	(20)
49	920.5	Office Services	0	0	0
50	920.6	Information Services	478	468	10
51	920.7	Materials Management	(134)	(94)	(40)
52		Other	249	193	56
53			3,056	2,860	196
54					
55	921	Expenses			
56	921.1	Executive & Senior Management	219	118	101
57	921.2	Legal	389	198	191
58	921.3	Human Resources	217	173	44
59	921.4	Finance & Accounting	63	38	25
60	921.5	Office Services	0	0	0
61	921.6	Information Services	222	200	22
62	921.7	Materials Management	(5)	(5)	0
63		Other	(35)	420	(455)
64			1,069	1,142	(72)
65					
66	922	Admin & General Transferred	0	(5)	5
67	923	Special Services	3,323	3,590	(267)
68	924	Insurance	944	783	161
69	932	Maintenance to General Plan	1,105	1,260	(155)
70	933	Transportation Equipment Expenses	917	778	139
71			6,289	6,407	(118)
72					
73		TOTAL	112,183	112,124	60
74					
75					
76					
77	Less:	Wheeling	(3,471)	(3,840)	369
78		Power Purchases	(66,629)	(67,576)	947
79		Water Fees	(7,918)	(8,371)	453
80					
81	**Operating & Maintenance Expense per Financial Statements**		**34,165**	**32,337**	**1,829**
	Add:	Capitalized Overhead	8,836	8,382	454
	Gross O&M per Financial Statements		43,001	40,719	2,283

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2007

		($000s)	
1	Amortization of Prior Year Incentives		
2	Amortization of 2006 Incentive	(2,523)	
3	True Up for 2006 Incentive	13	
4	Total Prior Year Incentive Amortization		(2,511)
5	Current Year Preliminary Flow Through Adjustments		
6	2007 Preliminary Interest Expense	42	
7	2007 Preliminary AFUDC/CWIP Decision Revenue	(895)	
8	Total 2007 Preliminary Flow Through Adjustments		(853)
9	Preliminary ROE Incentive Adjustment		
10	2007 Preliminary ROE Incentive	2,159	
	Total 2007 Preliminary ROE Incentive Adjustments		2,159
11	Total Regulatory Incentive Adjustments		($1,206)
12	Reconciliation to Income Statement:		
13	Provision for True-Up of 2007 Incentive[(1)]		(185)
14	Incentive Adjustments per Income Statement		($1,391)

(1) A provision for the 2007 true-up of incentives of $185,000 was recorded in 2007. This true-up from preliminary (as approved by Order G-162-06) to final incentives for2007 will flow through to 2009 Revenue Requirements.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2007

2007 Flow Through Adjustments	Approved		Forecast	Variance	Income Tax	After Tax Amount	Customer Share	Flow Through Adjustment
					($000s)			
1 Interest Expense (FBC: 28,620 & PLP:257)	28,877	*	28,813	(64)	(22)	(42)	100%	(42)
2 AFUDC/CWIP decision revenue shortfall	(4,135)		(2,776)	1,359	464	895	100%	895
5 Flow Through Adjustment								**853**

2007 ROE Incentive Adjustment	Approved		Forecast	Variance	Customer Share	ROE Incentive Adjustment
			(000s)			
1 Net Income (FBC: 25,970 & PLP: 252)	26,224	*	30,530			
2 Less: 2006 Rate Base Adjustment (After Tax)	(12)		-			
3 Net Income for ROE Incentive	26,212		30,530	4,318	50%	**(2,159)**
4						
5 Common Equity	296,138		297,646			
6						
7 Allowed ROE	8.77%					
8 Effective ROE	8.85%		10.26%	1.41%	50%	0.70%

(*) FortisBC Approved Earnings and Approved Interest Expense both include $10,000 for Interest on Deferral Account.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2007

		Normalized 2006	Decision [1] 2007	Actual 2007	Normalized 2007	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	59,763	57,912	62,771	62,366	4,454
2	Deduct:					
3	Interest Expense	26,112	28,620	28,731	28,731	111
4	ACCOUNTING INCOME	33,652	29,292	34,040	33,636	4,344
5						
6	Deductions					
7	Capital Cost Allowance	30,730	38,406	37,586	37,586	(820)
8	Capitalized Overhead	8,382	8,619	8,836	8,836	217
9	AFUDC	2,360	-	-	-	-
10	Additions to Deferred Charges	2,325	2,523	1,391	1,391	(1,132)
11	Financing Fees			921	921	
12	All Other (net effect)	(1,180)	1,106	(409)	(409)	(1,515)
13		42,617	50,654	48,325	48,325	(2,329)
14						
15	Additions					
16	Depreciation	26,746	30,565	30,949	30,949	384
17						
18	TAXABLE INCOME	17,780	9,204	16,664	16,260	7,056
19						
20	Tax Rate	34.12%	34.12%	34.12%	34.12%	0.00%
21						
22	Taxes Payable	6,067	3,140	5,686	5,548	2,408
23						
24	Prior Years' Overprovisions/(Underprovisions)	(302)	-	31	31	31
25	Deferred Charges Tax Effect	898	192	181	181	(11)
26	FORTISBC Tax Provision	6,663	3,332	5,898	5,760	2,428
27	Plus: PLP Tax Provision		58			(58)
28	REGULATORY TAX PROVISION	6,663	3,390	5,898	5,760	2,370

[1] Commission Orders G-159-06, G-162-06, G-20-07

SCHEDULE 4 – COMMON EQUITY

		Normalized 2006	Decision 2007 (1)	Actual 2007 ($000s)	Normalized 2007	Change from Decision
1	Share Capital	128,000	148,000	148,000	148,000	-
2	Retained Earnings	144,725	161,135	161,207	161,207	72
3	Opening Balance	272,725	309,135	309,207	309,207	72
4	Common Dividends	(10,200)	(11,000)	(11,800)	(11,800)	(800)
5	Add: Net Income	26,989 (2)	26,212	28,143	27,876	1,664
6	Share Adjustment	(17,878)		(17,878)	(17,878)	
7	Shares Issued	20,000	20,000	15,000	15,000	(5,000)
8	Closing Balance	291,636	344,347	322,673	322,405	(4,064)
9	SIMPLE AVERAGE	282,180	326,741	315,940	315,806	(1,996)
10	Adjustment for Share Issue	(13,573)	(6,575)	(11,100)	(11,100)	(4,525)
11	Deemed Equity Adjustment	-	(24,028)	-	-	24,028
12	AVERAGE COMMON EQUITY	268,608	296,138	304,840	304,706	8,568

(1) Commission Orders G-159-06, G-162-06, G-20-07

(2) In 2006 an adjustment was made to Common Equity to reflect the difference between the equity historically reported for regulated versus non-regulated operations in FortisBC Inc. In prior years, the inclusion of non-regulated equity in regulated equity resulted in deemed equity adjustments for rate setting purposes in order to reflect the deemed 60/40% Debt/Equity ratio. Therefore, the adjustment will have no impact on rates.

SCHEDULE 5 – RETURN ON CAPITAL

		Normalized 2006	Decision 2007 [(1)]	Actual 2007	Normalized 2007	Change from Decision
				($000s)		
1	Secured and Senior Unsecured Debt	385,968	401,885	433,691	433,691	31,806
2	Proportion	57.67%	54.30%	57.45%	57.46%	3.17%
3	Embedded Cost	6.49%	6.47%	6.50%	6.50%	0.03%
4	Cost Component	3.74%	3.51%	3.74%	3.74%	0.22%
5	Return	25,062	25,997	28,202	28,202	2,205
6	Short Term Debt	13,272	42,133	16,329	16,329	(25,804)
7	Proportion	1.98%	5.69%	2.16%	2.16%	(3.53%)
8	Embedded Cost	7.91%	6.20%	3.24%	3.24%	(2.96%)
9	Cost Component	0.16%	0.35%	0.07%	0.07%	(0.28%)
10	Return (expense)	1,050	2,870	529	529	(2,341)
11	Common Equity	268,608	296,138	304,840	304,706	8,568
12	Proportion	40.22%	40.01%	40.38%	40.37%	0.36%
13	Embedded Cost	10.05%	8.85%	9.23%	9.15%	0.30%
14	Cost Component	4.04%	3.54%	3.73%	3.69%	0.15%
15	Return	26,989	26,212	28,143	27,876	1,664
16	TOTAL CAPITALIZATION	667,848	740,156	754,860	754,726	14,570
17	Earned Return	53,100	55,079	56,873	56,606	1,527
18	RETURN ON CAPITAL	7.95%	7.44%	7.53%	7.50%	0.06%
19	RATE BASE	671,138	747,220	746,543	746,543	(677)
20	RETURN ON RATE BASE	7.91%	7.37%	7.62%	7.58%	0.21%

[(1)] Commission Orders G-159-06, G-162-06, G-20-07

2008 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2008

	Acct		Reference	Actual 2007	Decision [1] 2008	Actual 2008	Change from Decision
					($000s)		
1	101	Plant in Service, January 1	p. 3	943,920	1,075,766	1,062,070	(13,696)
2		Net Additions	p. 6	118,150	108,640	103,387	(5,253)
3		Plant in Service, December 31		1,062,070	1,184,406	1,165,457	(18,949)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	p. 8	13,112	6,787	7,214	427
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 11	14,473	16,062	16,227	165
9							
10				1,101,567	1,219,167	1,200,810	(18,357)
11		**Less:**					
12		Accumulated Depreciation	p. 13				
13		and Amortization		250,323	275,031	275,128	97
14	252	Contributions in Aid of Construction		78,351	80,694	86,783	6,089
15				328,674	355,725	361,911	6,186
16							
17		Depreciated Rate Base		772,893	863,441	838,899	(24,542)
18							
19		Prior Year Depreciated Utility Rate Base		712,911	782,422	772,893	(9,529)
20							
21		Mean Depreciated Utility Rate Base		742,902	822,932	805,896	(17,036)
22		**Add:**					
23		Allowance for Working Capital	p. 14	6,519	7,188	8,261	1,073
24		Adjustment for Capital Additions	p. 15	(2,878)	(7,273)	(11,591)	(4,318)
25							
26		Mid-Year Utility Rate Base		746,543	822,847	802,566	(20,281)

[1] Commission Orders G-147-07 and G-70-08.

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2008

Line	Account		December 31 2007	Additions	Retirements	December 31 2008
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	10,947	333	-	11,280
3	332	Reservoirs, Dams & Waterways	19,433	1,611	(5)	21,040
4	333	Water Wheels, Turbines and Gen.	54,503	2,223	(181)	56,545
5	334	Accessory Equipment	22,370	683	(142)	22,911
6	335	Other Power Plant Equipment	38,277	102	(30)	38,349
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			147,430	4,952	(358)	152,024
9		**Transmission Plant**				
10	350	Land Rights	7,079	-	-	7,079
11	350.1	Land Rights - Clearing	4,496	-	-	4,496
12	353	Station Equipment	135,378	32,151	-	167,529
13	355	Poles Towers & Fixtures	65,142	9,372	(15)	74,499
14	356	Conductors and Devices	62,601	9,354	-	71,955
15	359	Roads and Trails	817	-	-	817
16			275,513	50,876	(15)	326,374
17		**Distribution Plant**				
18	360	Land Rights	1,736	1,250	-	2,986
19	360.1	Land Rights - Clearing	5,856	1,250	-	7,106
20	362	Station Equipment	115,295	1,720	(73)	116,942
21	364	Poles Towers & Fixtures	105,392	9,172	(354)	114,210
22	365	Conductors and Devices	175,985	11,144	(588)	186,542
23	368	Line Transformers	83,699	6,695	(1,462)	88,933
24	369	Services	7,292	-	-	7,292
25	370	Meters	12,754	733	(298)	13,189
26	371	Installation on Customers' Premises	938	4,398	-	5,336
27	373	Street Lighting and Signal System	7,318	-	(46)	7,272
28			516,264	36,363	(2,821)	549,806
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	22,966	1,567	-	24,533
33	391	Office Furniture & Equipment	5,233	363	(1)	5,596
34	391.1	Computer Equipment	42,179	8,961	(163)	50,977
35	392	Transportation Equipment	16,447	1,628	(1,512)	16,563
36	394	Tools and Work Equipment	9,884	682	-	10,566
37	397	Communication Structures and Equipment	20,016	2,864	-	22,880
38			122,863	16,065	(1,675)	137,252
39						
40	101	**Plant in Service**	1,062,070	108,256	(4,869)	1,165,457
41	107.1	Plant under construction not subject				
42		to AFUDC	13,112			7,214
43	107.2	Plant under construction				
44		subject to AFUDC	44,956			54,177
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,132,050			1,238,760

Note: Differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2008

		CWIP Dec. 31, 2007	Reclassification	Actual Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
				($000s)		
Hydraulic Production						
1	P1U1 Upgrade & Life Extensions	-	-	-	-	-
2	P1U2 Headgate Rebuild	-	-	-	-	-
3	P1U3 Upgrade & Life Extension	23	-	430	-	453
4	P1U3 Headgate Rebuild	-	-	-	-	-
5	P1 Generator & Plant Cooling System	6	-	-	-	6
6	P2 Old Unit Repowering Phase 1	1,213	-	1,872	179	2,906
7	P3U1 Life Extension	3,183	-	2,433	5,616	-
8	P3U1 Headgate Rebuild	-	-	1	1	-
9	COR U1 Life Extension (replace Turbine)	-	102	650	752	-
10	P3U3 Life Extension	3,164	-	7,714	10,878	-
11	P3U3 Headgate Rebuild	449	-	460	-	910
12	P3 Poleyard Contaminated Site	-	-	115	-	115
13	P3U2 Bottom Ring Rebuild	-	-	53	-	53
14	P3 H/G Hoist Contr. Wire Rope	-	-	181	181	-
15	P1-P4 Upgrade Station Service Supply	-	672	498	1,170	-
16	All Plants Spare Unit Transformer	-	-	43	43	-
17	Generation Sustaining Under $500k	-	344	1,141	30	1,455
18	2007 PST Credit	-	(965)	29	-	(936)
19	P3 Completion	694	-	574	1,268	-
20	P3U2 Rebuild & Life Extension	(17)	-	-	-	(17)
21	P4U1 Headgate Rebuild	102	(102)	-	-	-
22	P1 Misc Upgrades	6	-	-	-	6
23	P2 Misc Upgrades	12	(12)	-	-	-
24	P3 Misc Upgrades	22	(22)	-	-	-
25	P4 Misc Upgrades	17	(17)	-	-	-
26		**8,875**	**-**	**16,195**	**20,118**	**4,952**
Transmission Plant						
27	Kootenay 230 KV Development	-	-	64	-	64
28	SOK Project (Vaseux Lake Terminal)	-	-	(106)	-	(106)
29	Okanagan Transmission Reinforcement	3,838	-	3,418	7,256	-
30	Benvoulin Distribution Source	-	-	-	-	-
31	Big White 138 KV Line & Substation	6,268	-	7,380	-	13,648
32	Ellison Distribution Source	3,690	-	7,810	11,501	-
33	Black Mountain Distribution Source	712	-	6,811	7,523	-
34	Fault Level Reduction	143	-	58	-	201
35	Naramata Rehabilitation	2,813	-	541	3,384	(29)
36	New East Osoyoos Source (Nk'Mip Sub)	-	-	144	-	144
37	Kettle Valley	15,539	-	4,802	1,401	18,940
38	Lambert Transformer # 2	(277)	-	-	-	(277)
39	Princeton Transformer Replace	(15)	-	8	-	(7)
40	Transmission Line Sustaining	-	-	3,038	-	3,038
41	Station Sustaining	1,172	-	5,246	1,233	5,186
42	Ootischenia Project	492	-	5,492	-	5,983
43	Capitalized Inventory	6,865	-	349	7,214	-
44	Crawford Bay Cap Inc	2,183	-	9	-	2,192
45	Glenmore Substation New Feeder	-	-	93	-	93
46	WestBench Regulator Bank	-	-	2	-	2
47	Hedley Stepup Transformer	-	-	6	-	6
48	18 L Breaker @ Waneta	3	-	1,797	-	1,800
49		**43,426**	**-**	**46,961**	**39,511**	**50,876**

UTILITY PLANT UNDER CONSTRUCTION, cont'd

AS AT DECEMBER 31, 2008

	CWIP Dec. 31, 2007	Reclassification	Actual Expenditures ($000s)	CWIP Dec 31, 2008	Additions to Plant in Service
Distribution Plant					
50 New Connects System Wide	-	-	24,434	-	24,434
51 Distribution Sustaining	-	-	8,475	-	8,475
52 Small Cap Improvements	-	-	73	-	73
53 Small Cap Improvements Unplanned - 2007	-	-	78	-	78
54 Small Cap Improvements Unplanned - 2008	-	-	754	-	754
55 HOL1 - OKM1 Tie KLO Rd	-	-	48	48	-
56 GLE6 Fdr High Rd - Clifton Rd	-	-	71	-	71
57 LEE2 - HOL5 Tie Add N.O.	-	-	163	163	-
58 Dilworth Development Loopfeed	-	-	384	-	384
60 GLE2 Spall/Springfield UG	-	-	1	-	1
61 HOL1-HOL2 Tie	20	-	138	-	157
62 LEE 2 Regulator	-	-	7	-	7
63 KER01 & KER02 Capacity Upgrades	-	-	7	-	7
64 PRI04 Capacity Upgrade	103	-	1,171	-	1,274
65 OKF03 Capacity Upgrade	120	-	112	-	232
66 CRA 02 Capacity Upgrade	-	-	4	-	4
67 Mckinley Landing Capacity Upgrade	1	-	413	-	414
68 VAL1 Feeder Capacity Upgrade	10	-	162	171	-
69	**253**	-	**36,492**	**382**	**36,363**
General Plant					
70 Distribution Station Automation	181	-	1,108	656	633
71 Protection and Communications Rehabilitation	410	-	1,764	-	2,174
72 Vehicles	-	-	1,628	-	1,628
73 Metering	-	-	278	-	278
74 Information Systems	4,892	-	4,543	668	8,767
75 Telecommunications	-	-	258	-	258
76 Buildings	31	-	1,527	55	1,504
77 Furniture & Fixtures	-	-	237	-	237
78 Tools & Equipment	-	-	587	-	587
79	**5,514**	-	**11,930**	**1,379**	**16,065**
80 **TOTAL**	**58,068**	-	**111,579**	**61,391**	**108,256**
81 Less Closing CWIP subject to AFUDC	**(44,956)**	-		**(54,177)**	
82 TOTAL CWIP not subject to AFUDC	**13,112**	-		**7,214**	

Note: Differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2008

		Balance at Dec. 31, 2007	Reclassification	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)			
1	Energy Management						
2	Energy Management Additions	19,126	72	2,693	-	(2,108)	19,783
3	Tax Impact	(12,905)	(72)	(835)	-	647	(13,165)
4	PLP Energy Management	113	-	-	-	(77)	36
5		**6,334**	**-**	**1,858**	**-**	**(1,539)**	**6,654**
6	Deferred Regulatory Expense						
7	Provision for True-up for 2006 Incentive	21	-	-	(21)	-	-
8	Deferred Revenue - Incentive Adjustment	(1,132)	-	-	1,305	-	173
9	2008 Incentive	-	-	(1,938)	-	-	(1,938)
10	2005 Revenue Requirements	353	-	-	-	(176)	176
11	Tax Impact	(101)	-	-	-	51	(50)
12	2006 Revenue Requirements	107	-	-	-	(53)	54
13	Tax Impact	(35)	-	-	-	18	(17)
14	2007 Revenue Requirements	36	-	1	-	(37)	-
15	Tax Impact	(11)	(1)	-	-	12	-
16	2008 Revenue Requirements	32	-	7	-	-	39
17	Tax Impact	(11)	-	(2)	-	-	(13)
18	2009 Revenue Requirements	-	-	15	-	-	15
19	Tax Impact	-	-	(5)	-	-	(5)
20	2008 COSA & rate design application	-	44	250	-	-	294
21	Tax Impact	-	(15)	(78)	-	-	(93)
22	2007 BC Hydro Rate Design	11	-	-	-	(11)	-
23	Tax Impact	(4)	-	-	-	4	-
24		**(735)**	**28**	**(1,750)**	**1,284**	**(193)**	**(1,366)**
25							
26	Preliminary and Investigative Charges	**321**	**-**	**614**	**(270)**	**-**	**664**
27	Other Deferred Charges and Credits						
28	Trail Office Lease Costs	191	-	-	-	(12)	179
29	Trail Office Rental to SD#20	(598)	-	-	(38)	-	(636)
30	Prepaid Pension Costs	6,657	1	1,895	-	-	8,553
31	Tax Impact	(480)	1	(587)	-	-	(1,067)
32	Post Retirement Benefits	(3,529)	-	(2,150)	-	-	(5,679)
33	Tax Impact	1,191	-	667	-	-	1,858
34	20 Year Transmission System Plan (2005 SDP)	329	-	-	-	(165)	164
35	Tax Impact	(16)	-	-	-	9	(7)
36	2008 System Development Plan Update	248	-	835	-	-	1,082
37	Tax Impact	(84)	-	(259)	-	-	(343)
38	2008 COSA & rate design application	44	(44)				-
39	Tax Impact	(15)	15				-
40	Automated Meter Reading Feasibility Study	68	-	174	-	-	243
41	Tax Impact	(23)	-	(54)	-	-	(77)
42	2005 Resource Plan	61	-	-	-	(30)	31
43	Tax Impact	(6)	-	-	-	3	(3)
44	2008 Resource Plan Update	217	-	188	-	-	405
45	Tax Impact	(74)	-	(58)	-	-	(132)
46	Renew BCH Power Purchase Agreement	4	-	14	-	-	18
47	Tax Impact	(1)	-	(4)	-	-	(6)
48	Revenue Protection	176	-	183	-	(176)	183
49	Tax Impact	(61)	-	(57)	-	61	(57)
50	Innovative Clean Energy Fund Levy Implementation	23	-	-	-	(23)	-
51	Tax Impact	(8)	-	-	-	8	-
52	PLP Potential Substation	25	-	-	-	(11)	14
53	PLP Settlement Costs	47	-	-	-	(16)	32
54	PLP Computer Software	109	-	-	-	(23)	86
55	PLP Deferred Pension Credit	(81)	-	-	-	12	(70)
56	PLP Deferred Rate Stabilization Account	(75)	-	-	-	75	-
57	ROW Reclamation (Pine Beetle Kill)	-	-	2,507	-	-	2,507
58	Tax Impact	-	-	(777)	-	-	(777)
59	International Financial Reporting Standards	-	-	131	-	-	131
60	Tax Impact	-	-	(40)	-	-	(40)
61	2008 City of Penticton - Carmi Substation	-	-	15	(15)	-	-
62	Tax Impact	-	-	(5)	5	-	-
63	Right of Way Encroachment Litigation	-	-	47	-	-	47
64	Tax Impact	-	-	(14)	-	-	(14)
65							
66							
67		**4,338**	**(28)**	**2,650**	**(49)**	**(288)**	**6,623**

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

		Balance at Dec. 31, 2007	Reclassification	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)			
68	Deferred Debt Issue Costs						
69	Series E	7	-	-	-	(3)	4
70	Series F	129	-	-	-	(13)	116
71	Series G	118	-	-	-	(9)	109
72	Series H	106	-	-	-	(14)	92
73	Series I	199	-	-	-	(14)	185
74	Series J	131	-	-	-	(65)	66
75	Series 04-1	1,501	-	-	-	(215)	1,286
76	Tax Impact	(51)	-	(20)	-	7	(63)
77	Series 05-1	1,156	-	-	-	(42)	1,114
78	Tax Impact	(238)	-	(85)	-	9	(314)
79	Series 07-1	1,241	-	5	-	(31)	1,216
80	Tax Impact	(85)	-	(79)	-	2	(160)
81		**4,215**	**-**	**(179)**	**-**	**(387)**	**3,651**
82							
83	TOTAL DEFERRED CHARGES (RATE BASE)	**14,473**	**-**	**3,193**	**965**	**(2,407)**	**16,227**
84	Non-Rate Base Deferred Charges						
85	Discount Forfeit Defence	**198**		**-**	**-**	**(198)**	**-**
86	Tax Impact	**(66)**		**-**	**-**	**66**	**-**
87	BC Hydro Amendment to 3808 (PPA Proceedings)	**-**		**37**	**-**	**-**	**37**
88	Tax Impact			**(11)**	**-**	**-**	**(11)**
89							
90	GRAND TOTAL DEFERRED CHARGES	**14,606**	**-**	**3,218**	**965**	**(2,539)**	**16,253**

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Differences due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2008

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2007	Deprec. Rate	Asset Balance Dec. 31, 2007	Depreciation Expense Dec. 31, 2008	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2008
			($000s)			($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(467)	2.6%	847	22	(289)	(735)
2	331	Structures and Improvements	4,571	1.2%	10,947	131	(37)	4,666
3	332	Reservoirs, Dams and Waterways	2,812	1.7%	19,433	330	(9)	3,133
4	333	Water Wheels, Turbines & Generators	3,279	2.2%	54,503	1,199	(653)	3,825
5	334	Accessory Electrical Equipment	7,253	2.4%	22,370	537	(258)	7,532
6	335	Other Power Plant Equipment	6,338	2.3%	38,277	880	(44)	7,175
7	336	Roads, Railroads, and Bridges	201	1.4%	1,053	15	-	216
8			23,987	2.1%	147,430	3,115	(1,291)	25,811
9		Transmission Plant						
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	-	(72)
11	350.1	Land Rights - Clearing	951	1.6%	4,496	72	-	1,023
12	353	Station Equipment	22,435	3.0%	135,378	4,061	(501)	25,996
13	355	Poles Towers & Fixtures	14,089	3.0%	65,142	1,955	(266)	15,779
14	356	Conductors and Devices	10,555	3.0%	62,601	1,879	(251)	12,183
15	359	Roads and Trails	9	2.9%	817	24	-	33
16			47,967	2.9%	275,513	7,992	(1,017)	54,942
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	1,736	-	-	-
19	360.1	Land Rights - Clearing	279	2.1%	5,856	123	-	402
20	362	Station Equipment	26,565	3.0%	115,295	3,459	(1,430)	28,594
21	364	Poles Towers & Fixtures	30,187	3.0%	105,392	3,162	(349)	33,001
22	365	Conductors and Devices	42,493	3.0%	175,985	5,280	(588)	47,185
23	368	Line Transformers	16,698	2.9%	83,699	2,427	(3,595)	15,530
24	369	Services	6,403	0.5%	7,292	36	-	6,439
25	370	Meters	4,545	3.5%	12,754	446	(134)	4,857
26	371	Installation on Customers' Premises	985	0.0%	938	-	-	985
27	373	Street Lighting and Signal Systems	1,471	2.4%	7,318	176	(47)	1,600
28			129,628	2.9%	516,264	15,108	(6,142)	138,594
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	-	(11)
31	390	Structures - Frame & Iron	528	0.8%	337	3	-	531
32	390.1	Structures - Masonry	2,474	2.9%	20,398	590	(72)	2,992
33	391	Office Furniture & Equipment	3,155	7.5%	5,233	393	(1)	3,547
34	391.1	Computer Equipment	25,810	10.6%	42,179	4,471	(163)	30,118
35	392	Transportation Equipment	4,036	0.4%	16,447	66	(1,161)	2,941
36	394	Tools and Work Equipment	4,668	9.5%	9,884	939	-	5,607
37	397	Communication Structures and Equipment	4,781	6.0%	20,016	1,201	(46)	5,936
38			45,442	6.4%	120,295	7,662	(1,443)	51,661
39								
40	108	Total Accumulated Depreciation	247,024	3.2%	1,059,502	33,877	(9,894)	271,008
41								
42		Deduct - Portion of CIAC Depreciated				(3,305)		
43								
44	403	Depreciation Expense				30,573		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,466		11,912	186		4,652
48	390	Leasehold Improvements	1,238		2,568	407		1,645
49		Rate Stabilization Adjustment	(2,487)	10.0%		311		(2,176)
50		Manual entry for buy out of lease	82			-	(82)	-
51		Total Accumulated Amortization	3,299			904	(82)	4,121
52								
53		Accumulated Amortization per						
54		Balance Sheet	250,323			31,477		275,128

Note: Differences due to rounding**.**

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2008

	Lag Days Calculation	Lag (Lead) Days	2008 Actual	2008 Extended	Weighted Average Lag Days
			($000s)		
1	**Revenue**				
2	Tariff Revenue	50.5	220,909	11,156	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	2,450	65	
5	Contract Revenue	44.3	1,601	71	
6	Miscellaneous Revenue	31.8	652	21	
7	Investment Income	15.0	333	5	
8			**$ 225,945**	**$ 11,318**	**50.1**
9					
10	**Expenses**				
11	Power Purchases	42.2	66,010	2,785	
12	Wheeling	40.2	3,655	147	
13	Water Fees	(1.0)	7,878	(8)	
14	*Operating Labour:*				
15	Salaries & Wages	5.3	14,273	76	
16	Employee Benefits	13.2	10,348	137	
17	Contracted Manpower	50.6	4,720	239	
18	Property Tax	2.6	11,036	29	
19	Rental of T&D Facilities	47.8	3,252	155	
20	Office Lease - Kelowna	(15.2)	222	(3)	
21	Office Lease - Trail	91.3	753	69	
22	Materials	45.6	1,507	69	
23	Insurance	(182.5)	589	(107)	
24	Income Tax	15.2	5,869	89	
25	Interest	82.9	30,163	2,501	
26			**$ 160,274**	**$ 6,176**	**38.5**
27					
28	**Net Lag/(Lead) Days**				**11.6**
29					
30					
31	**Working Capital Allowance**				
32					
33	**Lead-Lag Study Allowance**				
34	Net Lag Days/365 times Expenses				$ 5,075
35					
36	**Add Funds Unavailable:**				
37	Average Customer Loans (related to energy management)			4,902	
38	Average Employee Loans			370	
39	Average of Uncollectable Accounts			1,106	
40	Average Inventory (forecast monthly average investment)			700	
41					$ 7,078
42	**Less Funds Available:**				
43	Average Customer Deposits			3,212	
44	Average Employee Payroll Deductions			-	
45	Average Provincial Services Tax			447	
46	Average Goods and Services Tax			234	
47					$ 3,893
48					
49	**2008 ALLOWANCE FOR WORKING CAPITAL**				**$ 8,261**

Note: Differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2008

		Additions to Plant in Service [1] ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	1,564	11.5	1,499
2	February	3,411	10.5	2,985
3	March	1,928	9.5	1,526
4	April	15,829	8.5	11,212
5	May	10,518	7.5	6,574
6	June	6,948	6.5	3,764
7	July	3,950	5.5	1,810
8	August	6,305	4.5	2,364
9	September	3,058	3.5	892
10	October	3,989	2.5	831
11	November	19,030	1.5	2,379
12	December	19,989	0.5	833
13	**Total**	**96,519**		**36,669**
14	Less Simple Average			48,260
15	Adjustment to Capital Additions			**(11,591)**

16 [1] Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:

17	Gross Plant in Service Additions	108,256
18	CIAC	(11,737)
19	Net Capital Additions	**96,519**

Note: Differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2007	Decision [1] 2008	Actual 2008	Normalized 2008	Change from Decision
1	SALES VOLUME (GWh)	3084	3087	3,087	3,057	(30)
2						
3				($000s)		
4						
5	ELECTRICITY SALES REVENUE	209,232	220,950	220,909	219,032	(1,918)
6						
7	EXPENSES					
8	Power Purchases	66,616	68,538	66,010	64,786	(3,752)
9	Water Fees	7,918	7,858	7,878	7,878	20
10	Wheeling	3,471	3,622	3,655	3,655	33
11	Net O&M Expense	34,165	36,248	35,663	35,663	(585)
12	Property Tax	10,642	11,176	11,036	11,036	(140)
13	Depreciation and Amortization	30,949	34,356	34,016	34,016	(340)
14	Other Income	(5,504)	(5,030)	(5,035)	(5,035)	(5)
15	Incentive Adjustments	(1,391)	(1,284)	654	654	1,938
16	UTILITY INCOME BEFORE TAX	62,366	65,466	67,032	66,378	912
17	Less:					
18	INCOME TAXES	5,760	3,989	5,869	5,666	1,677
19						
20	EARNED RETURN	56,606	61,477	61,163	60,712	(765)
21	RETURN ON RATE BASE					
22	Utility Rate Base	746,543	822,847	802,566	802,566	(20,281)
23	Return on Rate Base	7.58%	7.47%	7.62%	7.57%	0.09%

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2008

	Acct.		2008	2007	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	360	586	(226)
3	536	Water Fees	7,878	7,918	(40)
4	542	Structures	596	552	44
5	543	Dams & Waterways	168	203	(35)
6	544	Electric Plant	504	352	152
7	545	Other Plant	254	235	19
8			9,759	9,846	(87)
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	66,010	66,629	(619)
12	556	System Control	1,371	960	411
13			67,381	67,589	(208)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	616	1,171	(555)
17	560R-2	System Planning	1,321	948	373
18	561	Load Dispatching	1,099	1,272	(173)
19	562	Transmission Station Expense	713	623	90
20	563R-1	Transmission Line Maintenance	296	171	125
21	563R-2	Transmission ROW Maintenance	505	650	(145)
22	565	Wheeling	3,655	3,471	184
23	567	Rents	3,252	3,268	(16)
24					
25	583R-1	Distribution Line Maintenance	3,294	2,545	749
26	583R-2	Distribution ROW Maintenance	1,628	1,516	112
27	586	Meter Expenses	922	1,027	(105)
28	592	Distribution Station Expense	1,153	1,112	41
29	596	Street Lighting	85	70	15
30	598	Other Plant	273	255	18
31			18,813	18,099	714
32					
33		CUSTOMER SERVICE			
34	901	Supervision & Administration	769	855	(86)
35	902	Meter Reading	1,762	1,841	(79)
36	903	Customer Billing	654	597	57
37	904	Credit & Collections	1,299	1,002	297
38	910	Customer Assistance	1,927	1,940	(13)
39			6,411	6,235	176

Note: Differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

	Acct.		2008	2007	Change
				($000s)	
40					
41		ADMINISTRATIVE AND GENERAL			
42	920	Salaries			
43	920.1	Executive & Senior Management	1,318	1,234	84
44	920.2	Legal	664	336	328
45	920.3	Human Resources	719	390	329
46	920.4	Finance & Accounting	1,112	503	609
47	920.6	Information Services	958	478	480
48	920.7	Materials Management	384	(134)	518
49		Other	199	249	(50)
50			5,355	3,056	2,299
51					
52	921	Expenses			
53	921.1	Executive & Senior Management	117	219	(101)
54	921.2	Legal	94	389	(295)
55	921.3	Human Resources	167	217	(50)
56	921.4	Finance & Accounting	103	63	40
57	921.6	Information Services	672	222	450
58	921.7	Materials Management	17	(5)	22
59		Other	414	(35)	449
60			1,584	1,069	515
61					
62	923	Special Services	954	3,323	(2,369)
63	924	Insurance	589	944	(355)
64	932	Maintenance to General Plant	1,380	1,105	275
65	933	Transportation Equipment Expenses	980	917	63
66			3,902	6,289	(2,387)
67					
68		TOTAL	113,206	112,183	1,023
69					
70					
71					
72	Less:	Wheeling	(3,655)	(3,471)	(184)
73		Power Purchases	(66,010)	(66,629)	619
74		Water Fees	(7,878)	(7,918)	40
75					
76	**O & M Expense per Financial Statements**		**35,663**	**34,165**	**1,498**

Note: Differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2008

		($000s)	
1	**Amortization of Prior Year Incentives**		
2	Amortization of 2007 Approved Incentives	(1,305)	
3	Amortization of 2006 Incentive true-up	21	
4			
5	**Total Amortization of Prior Year Incentives**		**(1,284)**
6			
7	**Current Year Preliminary Flow Through Adjustments**		
8	2008 Preliminary Interest Expense	958	
9	2008 Preliminary Pension Expense	138	
10	2008 Preliminary BC Tax Reduction	60	
11	2008 Preliminary Pope & Talbot Bad Debt	(390)	
12	2008 Prelim. Net Variance from forecast (Canpar, P&T & Weyerhaeuser)	(331)	
13			
14	Total 2008 Flow Through Adjustments	**435**	
15			
16	**Current Year Preliminary ROE Incentive Adjustments**		
17	2008 Preliminary ROE Incentive	**1,181**	
18			
19			
20	**Total Regulatory Incentive Adjustments**		**1,616**
21			
22			
23	**Current Year True-up to Actual** [1]		**322**
24			
25			
26	**Incentive Adjustments per Income Statement**		**654**

(1) A provision for true-up of incentives of $322,000 was recorded in 2008. This true-up from preliminary to final incentives for 2008 will flow through to 2010 Revenue Requirements.

Note: Differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT[1], cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

2008 Flow Through Adjustments	Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
				($000s)			
1 Interest Expense	31,789	30,400	(1,389)	(431)	(958)	100%	(958)
2 Pension Expense	2,739	2,539	(200)	(62)	(138)	100%	(138)
3 BC Tax Rate Reduction	-	-	-	60	(60)	100%	(60)
4 Pope & Talbot Bad Debt	-	565	565	175	390	100%	390
5 Net variance from forecast (Canpar / Pope / Weyerhaeuser)	1,291	811	480	149	331	100%	331
6 Flow Through Adjustment							**(435)**

2008 ROE Incentive Adjustment	Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
			($000s)		
7 Net Income for ROE Incentive	29,687	32,049	2,362	50%	(1,181)
8 Common Equity	329,139	321,123			
9 Allowed ROE	9.02%	9.98%	0.96%	50%	0.48%

(1) Pursuant to Order G-193-08

Note: Differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision[1] 2008	Actual 2008	Normalized 2008	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	62,366	65,466	67,032	66,378	912
2	Deduct:					
3	Interest on Non Rate Base Deferral Account		27	-	-	(27)
4	Interest Expense	28,731	31,762	30,163	30,163	(1,599)
5	ACCOUNTING INCOME	33,636	33,678	36,869	36,215	2,538
6						
7	Deductions					
8	Capital Cost Allowance	37,586	44,421	42,886	42,886	(1,535)
9	Capitalized Overhead	8,836	9,062	9,062	9,062	-
10	Additions to Deferred Charges for Tax Purpo	-	-	-	-	-
11	Incentive & Revenue Deferrals	1,391	1,284	(654)	(654)	(1,938)
12	Financing Fees	921	933	922	922	(11)
13	All Other (net effect)	(409)	281	611	611	330
14		48,325	55,981	52,827	52,827	(3,154)
15						
16	Additions					
17	Amortization of Deferred Charges	2,807	2,527	2,539	2,539	12
18	Depreciation	28,142	31,829	31,477	31,477	(352)
19		30,949	34,356	34,016	34,016	(340)
20						
21	TAXABLE INCOME	16,260	12,052	18,058	17,404	5,352
22						
23	Tax Rate	34.12%	31.50%	31.00%	31.00%	-0.50%
24						
25	Taxes Payable	5,548	3,796	5,598	5,395	1,599
26	Prior Years' Overprovisions/(Underprovisions)	31	-	87	87	87
27	Deferred Charges Tax Effect	181	193	184	184	(9)
28						
29	REGULATORY TAX PROVISION	5,760	3,989	5,869	5,666	1,677

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision 2008 [1]	Actual 2008 ($000s)	Normalized 2008	Change From Decision
1	Share Capital	148,000	168,000	163,000	163,000	(5,000)
2	Retained Earnings	161,207	159,899	159,673	159,405	(494)
3						
4	COMMON EQUITY - OPENING BALANCE	309,207	327,899	322,673	322,405	(5,494)
5						
6	Less Common Dividends	(11,800)	(13,400)	(13,400)	(13,400)	-
7						
8	Add: Net Income	27,876	29,688	31,001	30,550	862
9	Share Adjustment	(17,878)	-	(19)	(19)	(19)
10	Shares Issued	15,000	20,000	15,000	15,000	(5,000)
11						
12	COMMON EQUITY - CLOSING BALANCE	322,405	364,187	355,255	354,536	(9,651)
13						
14	SIMPLE AVERAGE	315,806	346,043	338,964	338,470	(7,573)
15						
16	Adjustment for Shares Issued	(11,100)	(4,110)	(4,925)	(4,925)	(815)
17	Deemed Equity Adjustment	-	(12,794)	-	-	12,794
18						
19	COMMON EQUITY - AVERAGE	304,706	329,139	334,039	333,546	4,407

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision 2008 [1]	Actual 2008 ($000s)	Normalized 2008	Change From Decision
1	Secured and Senior Unsecured Debt	433,691	489,468	489,468	489,468	-
2	Proportion	57.46%	59.48%	61.04%	61.04%	1.56%
3	Embedded Cost	6.50%	6.36%	6.36%	6.36%	0.00%
4	Cost Component	3.74%	3.78%	3.88%	3.88%	0.10%
5	Return	28,202	31,126	31,116	31,116	(10)
6						
7	Short Term Debt	16,329	4,240	(21,633)	(21,633)	(25,873)
8	Proportion	2.16%	0.52%	(2.70%)	(2.70%)	(3.22%)
9	Embedded Cost	3.24%	15.00%	4.40%	4.40%	(10.60%)
10	Cost Component	0.07%	0.08%	(0.12%)	(0.12%)	(0.20%)
11	Return (including fees)	529	636	(953)	(953)	(1,589)
12						
13						
14	Common Equity	304,706	329,139	334,039	333,546	4,407
15	Proportion	40.37%	40.00%	41.66%	41.62%	1.62%
16	Embedded Cost	9.15%	9.02%	9.28%	9.16%	0.14%
17	Cost Component	3.69%	3.61%	3.87%	3.81%	0.20%
18	Return	27,876	29,688	31,001	30,550	862
19						
20	TOTAL CAPITALIZATION	754,726	822,847	801,875	801,381	(21,466)
21	RATE BASE	746,543	822,847	802,566	802,566	(20,281)
22						
23	Earned Return	56,606	61,450	61,164	60,713	(737)
24						
25	RETURN ON CAPITAL	7.50%	7.47%	7.63%	7.58%	0.11%
26	RETURN ON RATE BASE	7.58%	7.47%	7.62%	7.56%	0.09%

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

2009 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2009

Line	Acct		Reference	Actual 2008	Decision 2009	Actual 2009	Change from Decision
				($000s)			
1	101	Plant in Service, January 1	p. 3	1,062,070	1,173,113	1,165,457	(7,656)
2		Net Additions	p. 6	103,387	119,750	108,019	(11,731)
3		Plant in Service, December 31		1,165,457	1,292,863	1,273,476	(19,387)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	p. 8	7,214	6,865	5,913	(952)
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 11	16,227	23,611	15,508	(8,103)
9							
10				1,200,810	1,335,251	1,306,809	(28,442)
11		**Less:**					
12		Accumulated Depreciation	p. 13				
13		and Amortization		275,128	303,463	301,384	(2,079)
14	252	Contributions in Aid of Construction		86,783	97,489	90,267	(7,222)
15				361,911	400,952	391,651	(9,300)
16							
17		Depreciated Rate Base		838,899	934,299	915,158	(19,141)
18							
19		Prior Year Depreciated Utility Rate Base		772,893	845,905	838,899	(7,006)
20							
21		Mean Depreciated Utility Rate Base		805,896	890,102	877,029	(13,073)
22							
23		**Add:**					
24		Allowance for Working Capital	p. 14	8,261	7,018	7,231	213
25		Adjustment for Capital Additions	p. 15	(11,591)	10,857	(16,577)	(27,434)
26							
27		Mid-Year Utility Rate Base		802,566	907,977	867,683	(40,294)

Note: Minor differences due to rounding

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2009

Line	Account		December 31 2008	Additions	Retirements & Reclass	December 31 2009
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	115	962
2	331	Structures and Improvements	11,280	295	439	12,014
3	332	Reservoirs, Dams & Waterways	21,040	1,549	1,855	24,444
4	333	Water Wheels, Turbines and Gen.	56,545	8,256	(3,419)	61,382
5	334	Accessory Equipment	22,911	4,883	(301)	27,493
6	335	Other Power Plant Equipment	38,349	2,308	236	40,893
7	336	Roads, Railroads and Bridges	1,053	-	234	1,287
8			152,024	17,292	(840)	168,476
9		**Transmission Plant**				
10	350	Land Rights	7,079	116	10	7,205
11	350.1	Land Rights - Clearing	4,496	450	852	5,798
12	353	Station Equipment	167,529	1,766	(31,060)	138,235
13	355	Poles Towers & Fixtures	74,499	4,498	(6,370)	72,627
14	356	Conductors and Devices	71,955	4,735	(6,241)	70,448
15	359	Roads and Trails	817	304	-	1,121
16			326,374	11,870	(42,809)	295,435
17		**Distribution Plant**				
18	360	Land Rights	2,986	338	(868)	2,456
19	360.1	Land Rights - Clearing	7,106	2,113	(742)	8,477
20	362	Station Equipment	116,942	32,446	31,843	181,231
21	364	Poles Towers & Fixtures	114,210	10,240	2,529	126,978
22	365	Conductors and Devices	186,542	15,691	6,754	208,987
23	368	Line Transformers	88,933	7,679	1,845	98,457
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,189	665	(577)	13,277
26	371	Installation on Customers' Premises	5,336	-	(4,398)	938
27	373	Street Lighting and Signal System	7,272	1,312	1,691	10,275
28			549,806	70,484	38,077	658,368
29		**General Plant**				
30	389	Land	5,800	4,589	909	11,297
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	24,533	1,614	(63)	26,083
33	391	Office Furniture & Equipment	5,596	5	(127)	5,475
34	391.1	Computer Equipment	50,977	5,837	71	56,886
35	392	Transportation Equipment	16,563	2,342	(1,353)	17,552
36	394	Tools and Work Equipment	10,566	658	(355)	10,869
37	397	Communication Structures and Equipment	22,880	1,083	(1,264)	22,698
38			137,252	16,127	(2,182)	151,197
39						
40	101	**Plant in Service**	1,165,457	115,773	(7,754)	1,273,476
41	107.1	Plant under construction not subject				
42		to AFUDC	7,214			5,913
43	107.2	Plant under construction				
44		subject to AFUDC	54,177			52,429
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,238,760			1,343,729

Note: Minor differences due to rounding

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2009

	CWIP Dec. 31, 2008	Actual Expenditures	CWIP Dec 31, 2009	Additions to Plant in Service
		($000s)		
Hydraulic Production				
1 Upper Bonnington Old Unit Repowering Phase 1	179	1,053	-	1,232
2 South Slocan U1 SS Life Extention & Turbine	5,616	8,135	13,751	-
3 South Slocan U1 Headgate Rebuild	1	680	681	-
4 Corra Linn U1 Life Extension	752	2,611	3,363	-
5 South Slocan U3 Life Extension	10,878	1,949	-	12,827
6 South Slocan Poleyard Contaminated Site	-	45	-	45
7 South Slocan H/G Hoist Contr, Wire Rope	181	764	945	-
8 All Plants Upgrade Station Service Supply	1,170	646	226	1,590
9 All Plants Spare Unit Transformer	43	1,408	-	1,451
10 Generation Sustaining & Miscellaneous Upgrades	30	1,056	358	729
11 South Slocan Completion	1,268	902	1,688	482
12 All Plants Lighting Upgrade	-	387	-	387
13 Corra Linn U2 ULE	-	33	33	-
14	**20,118**	**19,669**	**21,045**	**18,742**
Transmission Plant				
15 Okanagan Transmission Reinforcement	7,256	21,503	24,456	4,302
16 Benvoulin Substation Capacity Increase	-	4,110	4,110	-
17 Kelowna Distribution Capacity Requirements		271	271	-
17 Big White Transmission and Substation	-	110	-	110
18 Ellison Distribution Source	11,501	5,608	-	17,109
19 Black Mountain Distribution Source	7,523	7,196	-	14,720
19 Naramata Rehabilitation	3,384	3,654	-	7,038
20 Tarrys Capacity Increase	-	265	265	-
21 Kettle Valley Distribution Source	1,401	473	-	1,874
21 Recreation Capacity Increase	-	179	179	-
22 30 Line Conversion	-	866	866	-
23 Transmission Line Sustaining	-	3,424	(12)	3,436
23 Station Sustaining	1,233	3,476	5	4,704
24 Ootischenia	-	142	-	142
25 Capitalized Inventory	7,214	(1,301)	5,913	-
26 Duck Lake Expansion (BC Hydro Woods Lake Project)	-	10	10	-
27	**39,511**	**49,985**	**36,063**	**53,434**

Note: Minor differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION, cont'd

AS AT DECEMBER 31, 2009

	CWIP Dec. 31, 2008	Actual Expenditures	CWIP Dec 31, 2009	Additions to Plant in Service
		($000s)		
Distribution Plant				
28 Customer New Connections	-	15,833	-	15,833
29 Distribution Sustaining	-	12,517	-	12,517
29 Small Capacity Improvements Unplanned	-	596	-	596
30 Glenmore New Feeder		487	487	-
30 HOL1-OKM1 Tie KLO Rd.	48	270	-	318
31 BEP2/FRU1 Tie	-	22	22	-
31 LEE2-HOL5 Tie Add N.O.	163	346	-	509
32 VAL1 Feeder Capacity Upgrade	171	728	-	899
32	**382**	**30,799**	**509**	**30,673**
General Plant				
33 Distribution Substation Automation	656	1,784	725	1,716
34 Protection & Communication	-	765	-	765
35 Vehicles	-	2,342	-	2,342
36 Metering	-	431	-	431
37 Information Systems	668	4,768	-	5,436
38 Telecommunications	-	90	-	90
39 Buildings	55	1,270	-	1,325
40 Furniture & Fixtures	-	294	-	294
41 Tools & Equipment	-	525	-	525
42	**1,379**	**12,269**	**725**	**12,924**
43 **TOTAL**	**61,391**	**112,723**	**58,341**	**115,773**
44 Less Closing CWIP subject to AFUDC	**(54,177)**		**(52,429)**	
45 TOTAL CWIP not subject to AFUDC	**7,214**		**5,913**	

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2009

		Balance at Dec. 31, 2008	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2009
				($000s)		
1	**Demand Side Management**					
2	Energy Management Additions	19,783	3,424	-	(2,689)	20,518
3	Tax Impact	(13,165)	(1,028)	-	1,790	(12,402)
4	PLP Energy Management	36	-	-	(36)	-
5		**6,654**	**2,396**	**-**	**(934)**	**8,116**
6	**Deferred Regulatory Expense**					
7	Deferred Revenue - Incentive Adjustment	173	-	(173)	-	-
8	2008 Incentive	(1,938)	-	1,616	-	(322)
9	2009 Incentive	-	(3,458)	-	-	(3,458)
10	2005 Revenue Requirements	176	-	-	(176)	-
11	Tax Impact	(50)	-	-	50	-
12	2006 Revenue Requirements	54	-	-	(54)	-
13	Tax Impact	(17)	-	-	17	-
14	2008 Revenue Requirements	39	-	-	(39)	-
15	Tax Impact	(13)	-	-	13	-
16	2009 Revenue Requirements	15	27	-	-	43
17	Tax Impact	(5)	(8)	-	-	(13)
18	2010 Revenue Requirements	-	17	-	-	17
19	Tax Impact	-	(5)	-	-	(5)
20	Renew BCH Power Purchase Agreement	18	87	-	-	105
21	Tax Impact	(6)	(26)	-	-	(32)
22	Terasen Gas ROE Application	-	92	-	-	92
23	Tax Impact	-	(28)	-	-	(28)
24	Section 5 Provincial Transmission Inquiry	-	82	-	-	82
25	Tax Impact	-	(25)	-	-	(25)
26	BC Hydro Waneta Transaction Application	-	255	-	-	255
27	Tax Impact	-	(77)	-	-	(77)
28	BC Hydro Amendment to 3808 (PPA Proceedings)	-	114	-	-	114
29	Tax Impact	-	(35)	-	-	(35)
30	2009 COSA & RDA	294	469	-	-	763
31	Tax Impact	(93)	(141)	-	-	(233)
32		**(1,353)**	**(2,658)**	**1,443**	**(188)**	**(2,755)**
33						
34	**Preliminary and Investigative Charges**	**664**	**424**	**-**	**-**	**1,089**
35						
36	**Other Deferred Charges and Credits**					
37	Trail Office Lease Costs	179	-	-	(12)	167
38	Trail Office Rental to SD#20	(636)	-	(44)	-	(679)
39	Prepaid Pension Costs	8,553	363	-	-	8,916
40	Tax Impact	(1,067)	(109)	-	-	(1,176)
41	Post Retirement Benefits	(5,679)	(2,023)	-	-	(7,702)
42	Tax Impact	1,858	607	-	-	2,465
43	20 Year Transmission System Plan (2005 SDP)	164	-	-	(164)	-
44	Tax Impact	(7)	-	-	7	-
45	2008 System Development Plan Update	1,082	28	-	(541)	569
46	Tax Impact	(343)	(8)	-	172	(180)
47	Automated Meter Reading Feasibility Study	243	222	(465)	-	-
48	Tax Impact	(77)	(67)	144	-	-
49	2005 Resource Plan	31	-	-	(31)	-
50	Tax Impact	(3)	-	-	3	-
51	2008 Resource Plan Update	405	7	-	-	412
52	Tax Impact	(132)	(2)	-	-	(134)
53	2009 Resource Plan Update	-	157	-	-	157
54	Tax Impact	-	(47)	-	-	(47)
55	2011-2013 Integrated System Plan	-	182	-	-	182
56	Tax Impact	-	(54)	-	-	(54)
57	BC Hydro Rate Increase	-	1,370	(1,370)	-	-
58	Tax Impact	-	(411)	411	-	-
59	Revenue Protection	183	162	-	(183)	162
60	Tax Impact	(57)	(48)	-	57	(48)
61	DSM Study	-	96	-	-	96
62	Tax Impact	-	(29)	-	-	(29)
63	PLP Potential Substation	14	-	-	(14)	-
64	PLP Settlement Costs	32	-	-	(16)	16
65	PLP Computer Software	86	-	-	(23)	63
66	PLP Deferred Pension Credit	(70)	-	-	12	(58)
67	ROW Reclamation (Pine Beetle Kill)	2,507	-	-	(251)	2,257
68	Tax Impact	(777)	-	-	78	(700)
69	International Financial Reporting Standards	131	304	-	(130)	304
70	Tax Impact	(40)	(91)	-	40	(91)
71	Right of Way Encroachment Litigation	47	36	-	-	82
72	Tax Impact	(14)	(11)	-	-	(25)
73	Joint Pole Use Audit 2008	-	155	-	(31)	124
74	Tax Impact	-	(47)	-	9	(37)
75	NERC / MRC Set Up Cost	-	27	-	-	27
76	Tax Impact	-	(8)	-	-	(8)
77		**6,611**	**759**	**(1,323)**	**(1,019)**	**5,028**

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2009

		Balance at Dec. 31, 2008	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2009
				($000s)		
78	**Deferred Debt Issue Costs**					
79	Series E	4	-	-	(4)	-
80	Series F	116	-	-	(11)	105
81	Series G	109	-	-	(9)	100
82	Series H	92	-	-	(13)	79
83	Series I	185	-	-	(15)	171
84	Series J	66	-	-	(66)	-
85	Series 04-1	1,286	-	-	(214)	1,072
86	Tax Impact	(63)	(21)	-	8	(76)
87	Series 05-1	1,114	-	-	(41)	1,073
88	Tax Impact	(314)	(90)	-	12	(391)
89	Series 07-1	1,216	-	-	(32)	1,184
90	Tax Impact	(160)	(85)	-	3.30	(242)
91	MTN Series - 2009	-	1,016	-	-	1,016
92	Tax Impact	-	(61)	-	-	(61)
93		**3,651**	**759**	**-**	**(379)**	**4,030**
94						
95	**TOTAL DEFERRED CHARGES - RATE BASE**	**16,227**	**1,680**	**120**	**(2,520)**	**15,508**
96						
97	Automated Meter Reading Feasibility Study	-	-	465	-	465
98	Tax Impact	-	-	(144)	-	(144)
99	BC Hydro Amendment to 3808 (PPA Proceedings)	37	78	(114)	-	-
100	Tax Impact	(11)	(23)	35	-	-
101	**GRAND TOTAL DEFERRED CHARGES**	**16,253**	**1,735**	**361**	**(2,520)**	**15,829**

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Minor differences due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2009

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2008	Approved Deprec. Rate	Asset Balance Dec. 31, 2008	Depreciation Expense Dec. 31, 2009	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2009
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(735)	2.6%	847	25	115	(595)
2	331	Structures and Improvements	4,666	1.2%	11,280	141	405	5,211
3	332	Reservoirs, Dams and Waterways	3,133	1.7%	21,040	390	1,642	5,165
4	333	Water Wheels, Turbines & Generators	3,825	2.2%	56,545	1,177	(3,911)	1,092
5	334	Accessory Electrical Equipment	7,532	2.4%	22,911	547	(510)	7,568
6	335	Other Power Plant Equipment	7,175	2.3%	38,349	888	236	8,299
7	336	Roads, Railroads, and Bridges	216	1.4%	1,053	18	234	468
8			25,811	2.1%	152,024	3,186	(1,789)	27,208
9		Transmission Plant	-					-
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	10	(62)
11	350.1	Land Rights - Clearing	1,023	1.6%	4,496	90	852	1,965
12	353	Station Equipment	25,996	3.0%	167,529	4,095	(31,302)	(1,212)
13	355	Poles, Towers & Fixtures	15,779	3.0%	74,499	2,047	(6,701)	11,125
14	356	Conductors and Devices	12,183	3.0%	71,955	1,971	(6,661)	7,494
15	359	Roads and Trails	33	2.9%	817	24	-	56
16			54,942	2.5%	326,374	8,227	(43,802)	19,366
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	2,986	-	(868)	(868)
19	360.1	Land Rights - Clearing	402	2.1%	7,106	134	(742)	(206)
20	362	Station Equipment	28,594	3.0%	116,942	4,524	31,766	64,884
21	364	Poles, Towers & Fixtures	33,001	3.0%	114,210	3,515	1,629	38,145
22	365	Conductors and Devices	47,185	3.0%	186,542	5,820	5,360	58,365
23	368	Line Transformers	15,530	2.9%	88,933	2,680	1,108	19,318
24	369	Services	6,439	0.0%	7,292	36	-	6,475
25	370	Meters	4,857	3.5%	13,189	458	(282)	5,034
26	371	Installation on Customers' Premises	985	0.0%	5,336	-	(4,398)	(3,413)
27	373	Street Lighting and Signal Systems	1,600	2.4%	7,272	216	1,566	3,383
28			138,594	3.2%	549,806	17,384	35,139	191,117
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	909	897
31	390	Structures - Frame & Iron	531	0.8%	337	3	-	533
32	390.1	Structures - Masonry	2,992	3.0%	20,569	615	(64)	3,543
33	391	Office Furniture & Equipment	3,547	7.5%	5,596	410	(127)	3,831
34	391.1	Computer Equipment	30,118	10.6%	50,977	5,420	71	35,610
35	392	Transportation Equipment	2,941	0.4%	16,563	66	(958)	2,049
36	394	Tools and Work Equipment	5,607	9.5%	10,566	995	(355)	6,247
37	397	Communication Structures and Equipment	5,936	6.0%	22,880	1,300	(1,280)	5,956
38			51,661	6.6%	133,288	8,810	(1,804)	58,666
39								
40	108	Total Accumulated Depreciation	271,008	3.2%	1,161,493	37,606	(12,256)	296,357
41								
42		Deduct - Portion of CIAC Depreciated				(3,657)		
43								
44	403	Depreciation Expense				33,949		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,652		11,912	186		4,838
48	390.1	Leasehold Improvements	1,645		3,964	409		2,054
49		Rate Stabilization Adjustment	(2,176)	10.00%		311		(1,865)
50		Manual entry for buy out of lease	-			-	-	-
51		Total Accumulated Amortization	4,121			906	-	5,027
52								
53		Accumulated Amortization per						
54		Balance Sheet	275,128			34,856		301,384

Note: Minor differences due to rounding.

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2009

Lag Days Calculation	Lag (Lead) Days	2009 Actual ($000)	2009 Extended ($M)	Weighted Average Lag Days
Revenue				
Tariff Revenue	50.6	238,572	12,072	
Other Revenue:				
Apparatus and Facilities Rental	26.6	2,924	78	
Contract Revenue	44.3	1,400	62	
Miscellaneous Revenue	31.8	675	21	
Investment Income	15.0	188	3	
		$243,759	**$ 12,236**	**50.2**
Expenses				
Power Purchases	42.2	70,776	2,986	
Wheeling	40.2	4,003	161	
Water Fees	(1.0)	8,656	(9)	
Operating Labour:				
Salaries & Wages	5.3	13,557	72	
Employee Benefits	13.2	9,829	130	
Contracted Manpower	50.6	4,788	242	
Property Tax	2.6	11,573	30	
Rental of T&D Facilities	47.8	3,100	148	
Office Lease - Kelowna	(15.2)	797	(12)	
Office Lease - Trail	91.3	1,212	111	
Materials	45.6	2,714	124	
Insurance	(182.5)	705	(129)	
Income Tax	15.2	4,749	72	
Interest	82.9	33,411	2,770	
		$169,870	**$ 6,696**	**39.4**
Net Lag/(Lead) Days				**10.8**
Working Capital Allowance				
Lead-Lag Study Allowance				
Net Lag Days/365 times Expenses				$ 5,015
Add Funds Unavailable:				
Average Customer Loans (related to energy management)			4,538	
Average Employee Loans			441	
Average of Uncollectable Accounts			1,052	
Average Inventory (forecast monthly average investment)			597	
				$ 6,628
Less Funds Available:				
Average Customer Deposits			3,656	
Average Employee Payroll Deductions			-	
Average Provincial Services Tax			442	
Average Goods and Services Tax			314	
				$ 4,412
2009 ALLOWANCE FOR WORKING CAPITAL				**$ 7,231**

Note: Minor differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2009

		Additions to Plant in Service[1] ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	795	11.5	762
2	February	14,885	10.5	13,024
3	March	3,382	9.5	2,677
4	April	2,326	8.5	1,648
5	May	5,183	7.5	3,239
6	June	3,717	6.5	2,013
7	July	4,395	5.5	2,014
8	August	21,034	4.5	7,888
9	September	2,223	3.5	648
10	October	4,228	2.5	881
11	November	12,095	1.5	1,512
12	December	34,369	0.5	1,432
13	**Total**	**108,632**		**37,739**
14	Less Simple Average			54,316
15	Adjustment to Capital Additions			**(16,577)**

16 (1) *Expenditures are reduced by Contributions in Aid of Construction(CIAC) as follows:*

17	Gross Plant in Service Additions	115,773
18	CIAC	(7,141)
19	Net Capital Additions	**108,632**

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2008	Decision 2009	Actual 2009	Normalized 2009	Change from Decision
1	SALES VOLUME (GWh)	3,057	3,107	3,157	3,093	(14)
2						
3				($000s)		
4	ELECTRICITY SALES REVENUE	219,032	234,763	238,572	234,359	(404)
5						
6	EXPENSES					
7	Power Purchases	64,786	70,944	70,776	68,006	(2,938)
8	Water Fees	7,878	8,480	8,656	8,656	176
9	Wheeling	3,655	4,010	4,003	4,003	(7)
10	Net O&M Expense	35,663	37,258	36,702	36,702	(556)
11	Property Tax	11,036	11,561	11,573	11,573	12
12	Depreciation and Amortization	34,016	37,504	37,376	37,376	(128)
13	Other Income	(5,035)	(4,915)	(5,187)	(5,187)	(271)
14	Incentive Adjustments	654	(1,443)	2,014	2,014	3,458
15	UTILITY INCOME BEFORE TAX	66,378	71,364	72,659	71,216	(148)
16	Less:					
17	INCOME TAXES	5,666	4,354	4,749	4,316	(37)
18						
19	EARNED RETURN	60,712	67,010	67,910	66,900	(110)
20	RETURN ON RATE BASE					
21	Utility Rate Base	802,566	907,977	867,683	867,683	(40,294)
22	Return on Rate Base	7.56%	7.38%	7.83%	7.71%	0.33%

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2009

	Acct.		2009	2008	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	791	360	431
3	536	Water Fees	8,656	7,878	778
4	542	Structures	637	596	41
5	543	Dams & Waterways	117	168	(50)
6	544	Electric Plant	443	504	(61)
7	545	Other Plant	211	254	(43)
8			10,854	9,759	1,095
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	70,776	66,010	4,766
12	556	System Control	1,646	1,371	275
13			72,422	67,381	5,041
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	886	616	270
17	560R-2	System Planning	1,290	1,321	(31)
18	561	Load Dispatching	1,182	1,099	82
19	562	Transmission Station Expense	782	713	69
20	563R-1	Transmission Line Maintenance	127	296	(169)
21	563R-2	Transmission ROW Maintenance	472	505	(34)
22	565	Wheeling	4,003	3,655	348
23	567	Rents	3,100	3,252	(151)
24					-
25	583R-1	Distribution Line Maintenance	3,263	3,294	(32)
26	583R-2	Distribution ROW Maintenance	1,741	1,628	112
27	586	Meter Expenses	999	922	77
28	592	Distribution Station Expense	1,304	1,153	151
29	596	Street Lighting	96	85	12
30	598	Other Plant	353	273	79
31			19,596	18,813	784
32					
33		CUSTOMER SERVICE			
34	901	Supervision & Administration	831	769	62
35	902	Meter Reading	1,763	1,762	1
36	903	Customer Billing	669	654	15
37	904	Credit & Collections	625	1,299	(674)
38	910	Customer Assistance	2,240	1,927	313
39			6,129	6,411	(283)

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2009

	Acct.		2009	2008	Change
				($000s)	
40					
41		ADMINISTRATIVE AND GENERAL			
42	920	Salaries			
43	920.1	Executive & Senior Management	1,515	1,318	197
44	920.2	Legal	604	664	(60)
45	920.3	Human Resources	808	719	88
46	920.4	Finance & Accounting	1,068	1,112	(44)
47	920.6	Information Services	1,043	958	85
48	920.7	Materials Management	184	384	(200)
49		Other	252	199	53
50			5,474	5,355	119
51					
52	921	Expenses			
53	921.1	Executive & Senior Management	68	117	(49)
54	921.2	Legal	242	94	148
55	921.3	Human Resources	144	167	(23)
56	921.4	Finance & Accounting	115	103	13
57	921.6	Information Services	696	672	24
58	921.7	Materials Management	18	17	2
59		Other	446	414	32
60			1,730	1,584	146
61					
62	923	Special Services	767	954	(187)
63	924	Insurance	705	589	116
64	932	Maintenance to General Plant	1,802	1,380	422
65	933	Transportation Equipment Expenses	658	980	(322)
66			3,931	3,902	29
67					
68		TOTAL	120,137	113,206	6,930
69					
70					
71					
72	Less:	Wheeling	(4,003)	(3,655)	(348)
73		Power Purchases	(70,776)	(66,010)	(4,766)
74		Water Fees	(8,656)	(7,878)	(778)
75					-
76	O & M Expense per Financial Statements		**36,702**	**35,663**	**1,039**

Note: Minor differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2009

		($000s)	
1	**Amortization of Prior Year Incentives**		
2	Amortization of 2008 Approved Incentives	(1,616)	
3	Amortization of 2007 Incentive true-up	173	
4			
5	**Total Amortization of Prior Year Incentives**		**(1,443)**
6			
7	**Current Year Preliminary Flow Through Adjustments**		
8	2009 Preliminary Interest Expense	875	
9	2009 Preliminary Pension Expense	103	
10	2009 CCA Change, Computer Hardware	109	
11	2009 City of Nelson Export Sales	(18)	
12			
13	Total 2008 Flow Through Adjustments	**1,068**	
14			
15	**Current Year Preliminary ROE Incentive Adjustments**		
16	2008 Preliminary ROE Incentive	**1,300**	
17			
18			
19	**Total Regulatory Incentive Adjustments**		**2,368**
20			
21			
22	**Current Year True-up to Actual** (1)		**1,089**
23			
24			
25	**Incentive Adjustments per Income Statement**		**2,014**

(1) *A provision for true-up of incentives of $1,089,000 was recorded in 2009. This true-up from preliminary to final incentives for 2009 will flow through to 2011 Revenue Requirements.*

Note: Minor differences due to rounding.

SUMMARY OF PRELIMINARY INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2009

2009 Flow Through Adjustments	Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
				($000s)			
1 Interest Expense	34,803	33,553	(1,250)	(375)	(875)	100%	(875)
2 Pension Expense	3,318	3,171	(147)	(44)	(103)	100%	(103)
3 CCA Change, Computer Hardware	-	-	-	109	(109)	100%	(109)
4 City of Nelson Export Sales	-	26	26	8	18	100%	18
5 Flow Through Adjustment							**(1,068)**

2009 ROE Incentive Adjustment	Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
			($000s)		
6 Net Income for ROE Incentive	32,215	34,814	2,599	50%	**(1,300)**
7 Common Equity	363,191	347,644			
8 Allowed ROE	8.87%	10.01%	1.14%	50%	0.57%

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2009

		Normalized 2008	Decision 2009	Actual 2009	Normalized 2009	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	66,378	71,372	72,659	71,216	(156)
2	Deduct:					
3	Interest Expense	30,163	34,803	33,411	33,411	(1,392)
4						
5	ACCOUNTING INCOME	36,215	36,569	39,248	37,806	1,237
6						
7	Deductions:					
8	Capital Cost Allowance	42,886	48,149	50,764	50,764	2,615
9	Capitalized Overhead	9,062	9,315	9,315	9,315	0
10	Incentive & Revenue Deferrals	(654)	1,443	(2,014)	(2,014)	(3,458)
11	Financing Fees	922	1,034	910	910	(124)
12	All Other (net effect)	611	501	1,048	1,048	547
13		52,827	60,442	60,023	60,023	(419)
14						
15	Additions:					
16	Amortization of Deferred Charges	2,539	2,569	2,521	2,521	(48)
17	Depreciation	31,477	34,935	34,855	34,855	(80)
18		34,016	37,504	37,376	37,376	(128)
19						
20	TAXABLE INCOME	17,404	13,631	16,601	15,158	1,528
21						
22	Tax Rate	31.00%	30.00%	30.00%	30.00%	0.00%
23						
24	Taxes Payable	5,395	4,089	4,980	4,548	458
25	Prior Years' Overprovisions/(Underprovisions)	87	-	(487)	(487)	(487)
26	Deferred Charges Tax Effect	184	265	256	256	(9)
27						
28	REGULATORY TAX PROVISION	5,666	4,354	4,749	4,316	(37)

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2009

			Normalized 2008	Decision 2009	Actual 2009	Normalized 2009	Change From Decision
					($000s)		
1	Share Capital		163,000	183,000	178,000	178,000	(5,000)
2	Retained Earnings		159,405	177,140	177,255	176,536	(604)
3							
4	COMMON EQUITY - OPENING BALANCE		322,405	360,140	355,255	354,536	(5,604)
5							
6	Less:	Common Dividends	(13,400)	(14,500)	(14,500)	(14,500)	-
7							
8	Add:	Net Income	30,550	32,215	34,499	33,489	1,274
		Share Adjustment	(19)		-	-	-
9		Shares Issued	15,000	30,000	10,000	10,000	(20,000)
10							
11	COMMON EQUITY - CLOSING BALANCE		354,536	407,855	385,254	383,525	(24,330)
12							
13	SIMPLE AVERAGE		338,470	383,998	370,254	369,030	(14,967)
14							
15	Adjustment for Shares Issued		(4,925)	(3,658)	(3,726)	(3,726)	(68)
16	Deemed Equity Adjustment		-	(17,149)	-	-	17,149
17							
18	COMMON EQUITY - AVERAGE		333,546	363,191	366,528	365,304	2,113

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2009

		Normalized 2008	Decision 2009	Actual 2009	Normalized 2009	Change From Decision
				($000s)		
1	Secured and Senior Unsecured Debt	489,468	539,974	527,002	527,002	(12,973)
2	Proportion	61.04%	59.47%	60.66%	60.66%	1.19%
3	Embedded Cost	6.36%	6.32%	6.33%	6.33%	0.01%
4	Cost Component	3.88%	3.76%	3.84%	3.84%	0.08%
5	Return	31,116	34,112	33,363	33,363	(749)
6						
7	Short Term Debt	(21,633)	4,812	(24,722)	(24,722)	(29,534)
8	Proportion	(2.70%)	0.53%	(2.85%)	(2.85%)	(3.38%)
9	Embedded Cost	4.40%	14.36%	(0.19%)	(0.19%)	(14.55%)
10	Cost Component	(0.12%)	0.08%	0.01%	0.01%	(0.07%)
11	Return (including fees)	(953)	691	48	48	(643)
12						
13						
14	Common Equity	333,546	363,191	366,528	365,304	2,113
15	Proportion	41.62%	40.00%	42.19%	42.11%	2.11%
16	Embedded Cost	9.16%	8.87%	9.41%	9.17%	0.30%
17	Cost Component	3.81%	3.55%	3.97%	3.86%	0.31%
18	Return	30,550	32,215	34,499	33,489	1,274
19						
20	TOTAL CAPITALIZATION	801,381	907,977	868,808	867,584	(40,394)
21	RATE BASE	802,566	907,977	867,683	867,683	(40,294)
22						
23	Earned Return	60,713	67,018	67,909	66,900	(118)
24						
25	RETURN ON CAPITAL	7.58%	7.38%	7.82%	7.71%	0.33%
26	RETURN ON RATE BASE	7.56%	7.38%	7.83%	7.71%	0.33%

Note: Minor differences due to rounding.

2010 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2010

	Acct		Reference	Actual 2009	Decision 2010	Actual 2010	Change from Decision
				($000s)			
1	101	Plant in Service, January 1	p. 3	1,165,457	1,278,904	1,273,476	(5,428)
2		Net Additions	p. 6	108,019	155,585	130,141	(25,444)
3		Plant in Service, December 31		1,273,476	1,434,489	1,403,617	(30,872)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	p. 8	5,913	6,135	7,213	1,078
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 12	15,508	19,094	16,698	(2,396)
9							
10				1,306,809	1,471,630	1,439,440	(32,190)
11		**Less:**					
12		Accumulated Depreciation					
13		and Amortization	p. 13	301,384	336,919	323,203	(13,716)
14	252	Contributions in Aid of Construction		90,267	94,173	93,763	(409)
15				391,651	431,092	416,967	(14,126)
16							
17		Depreciated Rate Base		915,158	1,040,538	1,022,473	(18,064)
18							
19		Prior Year Depreciated Utility Rate Base		838,899	919,900	915,158	(4,742)
20							
21		Mean Depreciated Utility Rate Base		877,029	980,219	968,815	(11,404)
22							
23		**Add:**					
24		Allowance for Working Capital	p. 14	7,231	7,153	5,756	(1,397)
25		Adjustment for Capital Additions	p. 15	(16,577)	(12,259)	(28,934)	(16,676)
26							
27		Mid-Year Utility Rate Base		867,683	975,113	945,637	(29,477)

Note: Minor differences due to rounding

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2010

Line	Account		December 31 2009	Additions	Retirements & Reclass	December 31 2010
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,014	596	(2)	12,609
3	332	Reservoirs, Dams and Waterways	24,444	2,210	(10)	26,644
4	333	Water Wheels, Turbines and Gen.	61,382	12,327	(262)	73,448
5	334	Accessory Equipment	27,493	5,819	(379)	32,934
6	335	Other Power Plant Equipment	40,893	756	(7)	41,642
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			168,476	21,708	(659)	189,525
9		**Transmission Plant**				
10	350	Land Rights	7,205	66	-	7,271
11	350.1	Land Rights - Clearing	5,798	438	-	6,236
12	353	Station Equipment	138,235	12,766	(77)	150,925
13	355	Poles, Towers and Fixtures	72,627	20,100	(3,693)	89,033
14	356	Conductors and Devices	70,448	20,119	(3,664)	86,903
15	359	Roads and Trails	1,121	-	-	1,121
16			295,435	53,488	(7,434)	341,489
17		**Distribution Plant**				
18	360	Land Rights	2,456	232	-	2,689
19	360.1	Land Rights - Clearing	8,477	1,486	-	9,964
20	362	Station Equipment	181,231	18,301	(446)	199,086
21	364	Poles, Towers and Fixtures	126,978	10,917	(398)	137,498
22	365	Conductors and Devices	208,987	16,740	(770)	224,957
23	368	Line Transformers	98,457	7,659	(1,384)	104,732
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,277	526	(210)	13,593
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	10,275	1,258	(47)	11,485
28			658,368	57,121	(3,255)	712,234
29		**General Plant**				
30	389	Land	11,297	796	-	12,093
31	390	Structures-Frame and Iron	337	-	-	337
32	390.1	Structures-Masonry	26,083	961	-	27,045
33	391	Office Furniture and Equipment	5,475	255	-	5,729
34	391.1	Computer Equipment	56,886	6,100	(111)	62,875
35	392	Transportation Equipment	17,552	932	(729)	17,755
36	394	Tools and Work Equipment	10,869	495	(68)	11,296
37	397	Communication Structures and Equipment	22,698	540	-	23,238
38			151,197	10,079	(908)	160,368
39						
40	101	**Plant in Service**	1,273,476	142,396	(12,256)	1,403,617
41	107.1	Plant under construction not subject				
42		to AFUDC	5,913			7,213
43	107.2	Plant under construction				
44		subject to AFUDC	52,429			50,769
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,343,729			1,473,511

Note: Minor differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2010

		CWIP Dec. 31, 2009	Actual Expenditures	CWIP Dec. 31, 2010	Additions to Plant in Service
			($000s)		
Hydraulic Production					
1	All Plants Spare Unit Transformer	-	107	-	107
2	Lower and Upper Bonnington Communication Network Comp.	86	257	343	-
3	All Plants Fire Safety Upgrade Phase 1	40	38	-	78
4	South Slocan U1 Life Extension & Turbine	13,751	1,591	-	15,342
5	South Slocan U1 Head Gate Rebuild	681	84	-	765
6	All Plants Public Safety & Security Phase 1	11	90	-	101
7	South Slocan Poleyard Contaminated Site	-	(23)	-	(23)
8	Lower Bonnington & Corra Linn Capital Planning 2008 Project	1	(1)	-	-
9	Upper Bonnington Old Unit Repowering Phase 1	-	318	-	318
10	All Plants Upgrade Station Service Supply	226	1,228	78	1,376
11	South Slocan H/G Hoist, Control, Wire Rope Upgrade	945	145	-	1,091
12	South Slocan Plant Completion	1,688	649	-	2,337
13	Corra Linn U1 Life Extension & Turbine	3,363	9,647	13,010	-
14	Corra Linn U2 Life Extension & Turbine	33	3,505	3,265	273
15	South Slocan Dam Rehabilitation Study	4	28	-	32
16	Upper Bonnington Extension Trash Rack Gantry Replacement	-	204	204	-
17	All Plants Spare Exciter Transformer	31	105	-	136
18	Lower Bonnington Intake Area Upgrade Phase 2	-	31	-	31
19	South Slocan Domestic Water Supply Phase 3	40	46	86	-
20	All Plants 2009 Pump Upgrades	130	79	-	209
21	All Plants Lighting Upgrade	-	256	-	256
22	Upper Bonnington Tailrace Gate Corrosion Control	-	131	-	131
23	Queen's Bay Level Gauge Building Phase 1	14	5	18	-
24	2011 Projects	-	11	11	-
25		**21,045**	**18,531**	**17,015**	**22,560**
Transmission Plant					
26	Ellison Distribution Source	-	102	-	102
27	Black Mountain Distribution Source	-	(6)	-	(6)
28	Okanagan Transmission Reinforcement	24,456	55,715	32,744	47,427
28	Benvoulin Distribution Source	4,110	11,435	-	15,544
29	Naramata Rehabilitation	-	(506)	-	(506)
30	Huth Split Bus	-	241	241	(0)
30	Capitalized Inventory	5,913	(580)	5,333	-
31	Recreation Capacity Increase	179	3,447	-	3,626
32	Tarrys Capacity Increase	265	51	-	316
32	Kelowna Distribution Capacity Requirements	271	493	-	763
33	30 Line Conversion	866	3,689	-	4,555
34	Transmission Line Sustaining	(12)	3,428	84	3,332
34	Station Sustaining	5	3,140	553	2,592
35	Duck Lake Expansion (BC Hydro Woods Lake Project)	10	(10)	-	-
36	2011 Projects	-	10	10	-
37		**36,063**	**80,647**	**38,965**	**77,745**

Note: Minor differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION, cont'd

AS AT DECEMBER 31, 2010

		CWIP Dec. 31, 2009	Actual Expenditures	CWIP Dec. 31, 2010	Additions to Plant in Service
			($000s)		
Distribution Plant					
38	Customer New Connections	-	15,927	-	15,927
39	Distribution Sustaining	-	12,605	-	12,605
40	Small Capacity Improvements Unplanned	-	749	-	749
41	New Glenmore Feeder	487	121	-	608
42	Airport Way Upgrade (Ellison Feeder 3)	-	822	-	822
43	Oliver Feeder 1 New Regulator		123	-	123
44	Beaver Park Feeder 2 to Fruitvale Feeder 1 Distribution Tie Upgrade	22	837	-	859
45	2011 Projects	-	108	108	-
46		**509**	**31,291**	**108**	**31,692**
General Plant					
47	Distribution Substation Automation	725	1,488	579	1,634
48	Protection & Communication	-	680	192	488
49	Mandatory Reliability Compliance (MRC)	-	1,811	738	1,073
50	Vehicles	-	1,318	386	932
51	Metering	-	187	-	187
52	Information Systems	-	4,309	-	4,309
53	Telecommunications	-	52	-	52
54	Buildings	-	948	-	948
55	Furniture & Fixtures	-	268	-	268
56	Tools & Equipment	-	507	-	507
57		**725**	**11,568**	**1,895**	**10,398**
58	**TOTAL**	**58,341**	**142,038**	**57,982**	**142,396**
59	Less Closing CWIP subject to AFUDC	**(52,429)**		**(50,769)**	
60	Total CWIP not subject to AFUDC	**5,913**		**7,213**	

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2010

		Balance at Dec. 31, 2009	Additions and Transfers	Amortized to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2010
1	**Demand Side Management**					
2	Energy Management Additions	20,518	3,714	-	(3,272)	20,961
3	Tax Impact	(12,402)	(1,059)	-	933	(12,528)
4		**8,116**	**2,656**	**-**	**(2,339)**	**8,433**
5	**Deferred Regulatory Expense**					
6	2008 Incentive	(322)	-	322	-	-
7	2009 Incentive	(3,458)	-	2,368	-	(1,090)
8	2010 Incentive	-	(2,061)			(2,061)
9	2009 Revenue Requirements	43	-	-	(43)	-
10	Tax Impact	(13)	-	-	13	-
11	2010 Revenue Requirements	17	58	-	-	75
12	Tax Impact	(5)	(17)	-	-	(22)
13	2011 Revenue Requirements	-	35	-	-	35
14	Tax Impact	-	(10)	-	-	(10)
15	Renew BCH Power Purchase Agreement	105	4	-	-	109
16	Tax Impact	(32)	(1)	-	-	(33)
17	Terasen Gas ROE Application	92	(16)	-	-	76
18	Tax Impact	(28)	4	-	-	(23)
19	Section 5 Provincial Transmission Inquiry	82	8	-	-	90
20	Tax Impact	(25)	(2)	-	-	(27)
21	BC Hydro Waneta Transaction Application	255	29	-	-	284
22	Tax Impact	(77)	(8)	-	-	(85)
23	BC Hydro Amendment to 3808 (PPA Proceedings)	114	-	-	(38)	76
24	Tax Impact	(35)	-	-	12	(23)
25	2009 COSA & RDA	763	946	-	-	1,708
26	Tax Impact	(233)	(269)	-	-	(503)
27	Shaw Application for Use of Transmission Facilities	-	288	-	-	288
28	Tax Impact	-	(82)	-	-	(82)
29	Tariff Amendment - Adaptive Street Lighting	-	3	-	-	3
30	Tax Impact	-	(1)	-	-	(1)
31	2012 Integrated System Plan	-	75	-	-	75
32	Tax Impact	-	(21)	-	-	(21)
33	Section 71 Filing (Waneta Expansion)	-	360	-	-	360
34	Tax Impact	-	(103)	-	-	(103)
35		**(2,755)**	**(781)**	**2,690**	**(56)**	**(903)**
36						
37	**Preliminary and Investigative Charges**	**1,089**	**2,144**	**(797)**	**-**	**2,435**
38						
39	**Other Deferred Charges and Credits**					
40	Trail Office Lease Costs	167	-	-	(12)	155
41	Trail Office Rental to SD#20	(679)	-	(50)	-	(729)
42	Prepaid Pension Costs	8,916	(1,468)	-	-	7,448
43	Tax Impact	(1,176)	418	-	-	(757)
44	Post Retirement Benefits	(7,702)	(2,619)	-	-	(10,321)
45	Tax Impact	2,465	746	-	-	3,211
46	2008 System Development Plan Update	569	-	-	(569)	-
47	Tax Impact	(180)	-	-	180	-
48	Resource Plan	569	220	-	-	789
49	Tax Impact	(182)	(63)	-	-	(244)
50	2011-2013 Integrated System Plan	182	(182)	-	-	-
51	Tax Impact	(54)	54	-	-	-
52	BC Hydro Rate Increase	-	470	(470)	-	-
53	Tax Impact	-	(134)	134	-	-
54	Revenue Protection	162	221	-	(162)	221
55	Tax Impact	(48)	(63)	-	48	(63)
56	DSM Study	96	163	-	-	259
57	Tax Impact	(29)	(47)	-	-	(75)
58	PLP Settlement Costs	16	-	-	(16)	-
59	PLP Computer Software	63	-	-	(23)	40
60	PLP Deferred Pension Credit	(58)	-	-	12	(46)
61	ROW Reclamation (Pine Beetle Kill)	2,257	-	-	(251)	2,006
62	Tax Impact	(700)	-	-	78	(622)
63	International Financial Reporting Standards	304	214	-	(304)	214
64	Tax Impact	(91)	(61)	-	91	(61)
65	Right of Way Encroachment Litigation	82	9	-	-	91
66	Tax Impact	(25)	(3)	-	-	(28)
67	Joint Pole Use Audit 2008	124	-	-	(31)	93
68	Tax Impact	(37)	-	-	9	(28)
69	NERC / MRC Set Up Cost	27	821	-	-	848
70	Tax Impact	(8)	(234)	-	-	(242)
71	Harmonized Sales Tax Implementation Project	-	222	-	-	222
72	Tax Impact	-	(63)	-	-	(63)
73	Pope & Talbot Litigation	-	23	-	-	23
74	Tax Impact	-	(7)	-	-	(7)
75		**5,028**	**(1,360)**	**(386)**	**(950)**	**2,333**

Note: Minor differences due to rounding

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2010

		Balance at Dec. 31, 2009	Additions and Transfers	Amortized to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2010
76	**Deferred Debt Issue Costs**					
77	Series F	105	-	-	(35)	70
78	Series G	100	-	-	(7)	93
79	Series H	79	-	-	(11)	67
80	Series I	171	-	-	(14)	157
81	Series 04-1	1,072	-	-	(214)	858
82	Tax Impact	(76)	-	-	15	(61)
83	Series 05-1	1,073	-	-	(41)	1,032
84	Tax Impact	(391)	-	-	15	(376)
85	Series 07-1	1,184	-	-	(31)	1,153
86	Tax Impact	(242)	(85)	-	6	(320)
87	MTN - 2009	1,016	(25)	-	(34)	957
88	Tax Impact	(61)	(59)	-	2	(118)
89	MTN - 2010	-	941	-	-	941
90	Tax Impact	-	(54)	-	-	(54)
91		**4,030**	**719**	**-**	**(350)**	**4,399**
92						
93	**TOTAL DEFERRED CHARGES (RATE BASE)**	**15,508**	**3,377**	**1,507**	**(3,695)**	**16,698**
94	**Deferred Charges (Non Rate Base)**					
95	Automated Meter Reading Feasibility Study	465	455	-	-	920
96	Tax Impact	(144)	144	-	-	-
97	**GRAND TOTAL DEFERRED CHARGES**	**15,829**	**3,976**	**1,507**	**(3,695)**	**17,618**

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Rows 48-49 2008 Resource Plan and 2009 Resource Plan have been combined.

Rows 95-96: Pursuant to the Negotiated Settlement Agreements for the 2010 and 2011 Revenue Requirements, AMI costs are being collected in a non-rate base deferral account that will collect AFUDC.

Note: Minor differences due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2010

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2009	Approved Deprec. Rate	Asset Balance Dec. 31, 2009	Depreciation Expense Dec. 31, 2010	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2010
					($000s)			
		Hydraulic Production Plant						
1	330	Land Rights	(595)	2.6%	962	25	-	(570)
2	331	Structures and Improvements	5,211	1.2%	12,014	144	(13)	5,343
3	332	Reservoirs, Dams and Waterways	5,165	1.7%	24,444	416	(45)	5,535
4	333	Water Wheels, Turbines and Generators	1,092	2.2%	61,382	1,350	(834)	1,608
5	334	Accessory Electrical Equipment	7,568	2.4%	27,493	660	(616)	7,613
6	335	Other Power Plant Equipment	8,299	2.3%	40,893	941	(21)	9,219
7	336	Roads, Railroads, and Bridges	468	1.4%	1,287	18	-	486
8			27,208	2.1%	168,476	3,554	(1,529)	29,233
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	7,205	-	-	(62)
11	350.1	Land Rights - Clearing	1,965	1.6%	5,798	97	-	2,062
12	353	Station Equipment	(1,212)	3.0%	138,235	4,147	(612)	2,323
13	355	Poles, Towers and Fixtures	11,125	3.0%	72,627	2,180	(4,987)	8,318
14	356	Conductors and Devices	7,494	3.0%	70,448	2,112	(4,955)	4,651
15	359	Roads and Trails	56	2.9%	1,121	33	-	89
16			19,366	2.9%	295,435	8,569	(10,554)	17,381
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	2,456	-	-	(868)
19	360.1	Land Rights - Clearing	(206)	2.1%	8,477	178	-	(28)
20	362	Station Equipment	64,884	3.0%	181,231	5,437	(1,422)	68,899
21	364	Poles, Towers and Fixtures	38,145	3.0%	126,978	3,809	(1,224)	40,730
22	365	Conductors and Devices	58,365	3.0%	208,987	6,270	(2,089)	62,546
23	368	Line Transformers	19,318	2.9%	98,457	2,855	(2,096)	20,076
24	369	Services	6,475	0.0%	7,292	36	-	6,511
25	370	Meters	5,034	3.5%	13,277	465	(204)	5,294
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,383	2.4%	10,275	247	(166)	3,464
28			191,117	2.9%	658,368	19,296	(7,201)	203,212
29		General Plant						
30	389	Land	897	0.0%	11,297	-	-	897
31	390.0	Structures - Frame & Iron	533	0.8%	337	3	-	536
32	390	Structures - Masonry	3,543	3.0%	21,682	650	-	4,194
33	391	Office Furniture and Equipment	3,831	7.5%	5,475	411	-	4,241
34	391.1	Computer Equipment	35,610	10.6%	56,886	6,030	(111)	41,529
35	392	Transportation Equipment	2,049	0.4%	17,552	70	(636)	1,484
36	394	Tools and Work Equipment	6,247	9.5%	10,869	1,033	(68)	7,211
37	397	Communication Structures and Equipment	5,956	6.0%	22,698	1,362	(29)	7,288
38			58,666	6.5%	146,796	9,558	(844)	67,381
39								
40	108	Total Accumulated Depreciation	296,357	3.2%	1,269,075	40,977	(20,127)	317,207
41								
42		Deduct - Portion of CIAC Depreciated				(3,871)		
43								
44	403	Depreciation Expense				37,106		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,838		11,912	186		5,024
48	390.1	Leasehold Improvements	2,054		4,401	472		2,526
49		Rate Stabilization Adjustment	(1,865)	10.00%		311		(1,554)
50		Total Accumulated Amortization	5,027			969		5,996
51								
52		Accumulated Amortization per						
53		Balance Sheet	301,384			38,075		323,203

Note: Minor differences due to rounding.

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2010

	Lag Days Calculation	**Lag (Lead) Days**	**2010 Actual ($000s)**	**2010 Extended ($000s)**	**Weighted Average Lag Days**
1	**Revenue**				
2	Tariff Revenue	50.6	246,791	12,488	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	4,005	106	
5	Contract Revenue	44.3	1,562	69	
6	Miscellaneous Revenue	31.8	662	21	
7	Investment Income	15.0	224	3	
8			**253,244**	**12,688**	**50.1**
9					
10	**Expenses**				
11	Power Purchases	42.2	71,964	3,036	
12	Wheeling	40.2	4,050	163	
13	Water Fees	(1.0)	9,256	(9)	
14	Operating Labour:				
15	Salaries & Wages	5.3	13,011	69	
16	Employee Benefits	13.2	9,758	129	
17	Contracted Manpower	50.6	5,854	296	
18	Property Tax	2.6	12,238	32	
19	Rental of T&D Facilities	47.8	3,115	149	
20	Office Lease - Kelowna	(15.2)	819	(12)	
21	Office Lease - Trail	91.3	1,212	111	
22	Materials	45.6	2,173	99	
23	Insurance	(182.5)	676	(123)	
24	Income Tax	15.2	4,544	69	
25	Interest	82.9	35,138	2,913	
26			**173,809**	**6,920**	**39.8**
27					
28	**Net Lag/(Lead) Days**				**10.3**
29					
30					
31	**Working Capital Allowance**				($000s)
32					
33	**Lead-Lag Study Allowance**				4,897
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Average Customer Loans (related to energy management)			3,599	
38	Average Employee Loans			405	
39	Average of Uncollectable Accounts			1,037	
40	Average Inventory (forecast monthly average investment)			468	
41					5,509
42	**Less Funds Available:**				
43	Average Customer Deposits			4,046	
44	Average Employee Payroll Deductions			-	
45	Average Provincial Services Tax			278	
46	Average Goods and Services Tax & HST			326	
47					4,650
48					
49	**2010 ALLOWANCE FOR WORKING CAPITAL**				**5,756**

Note: Minor differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2010

		Additions to Plant in Service ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	1,509	11.5	1,446
2	February	17,460	10.5	15,278
3	March	3,544	9.5	2,806
4	April	3,799	8.5	2,691
5	May	3,430	7.5	2,144
6	June	4,882	6.5	2,645
7	July	2,979	5.5	1,366
8	August	3,190	4.5	1,196
9	September	4,391	3.5	1,281
10	October	4,496	2.5	937
11	November	38,830	1.5	4,854
12	December	46,518	0.5	1,938
13	**Total**	**135,029**		**38,580**
14	Less Simple Average			67,514
15	Adjustment to Capital Additions			**(28,934)**

16 * *Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:*

		($000s)
17	Gross Plant in Service Additions	142,396
18	CIAC	(7,368)
19	Net Capital Additions	**135,029**

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2009	Decision 2010	Actual 2010	Normalized 2010	Change from Decision
1	SALES VOLUME (GWh)	3,093	3,199	3,046	3,094	(105)
2						
3				($000s)		
4	ELECTRICITY SALES REVENUE	234,359	259,274	246,791	250,235	(9,039)
5						
6	EXPENSES					
7	Power Purchases	68,006	80,408	71,964	73,733	(6,675)
8	Water Fees	8,656	9,068	9,256	9,256	188
9	Wheeling	4,003	4,019	4,050	4,050	31
10	Net O&M Expense	36,702	38,116	36,619	36,619	(1,497)
11	Property Tax	11,573	12,548	12,238	12,238	(310)
12	Depreciation and Amortization	37,376	42,028	41,771	41,771	(257)
13	Other Income	(5,187)	(5,025)	(6,453)	(6,453)	(1,428)
14	Incentive Adjustments	2,014	(2,690)	(629)	(629)	2,061
15	UTILITY INCOME BEFORE TAX	71,216	80,803	77,975	79,650	(1,153)
16	Less:					
17	INCOME TAXES	4,316	5,407	4,544	5,048	(359)
18						
19	EARNED RETURN	66,900	75,396	73,431	74,602	(794)
20	RETURN ON RATE BASE					
21	Utility Rate Base	867,683	975,113	945,637	945,637	(29,476)
22	Return on Rate Base	7.71%	7.73%	7.77%	7.89%	0.16%

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2010

	Acct.		2010	2009	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	584	791	(207)
3	536	Water Fees	9,256	8,656	600
4	542	Structures	651	637	14
5	543	Dams & Waterways	204	117	87
6	544	Electric Plant	627	443	185
7	545	Other Plant	134	211	(77)
8			11,456	10,854	602
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	71,964	70,776	1,188
12	556	System Control	1,653	1,646	7
13			73,617	72,422	1,195
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	768	886	(118)
17	560R-2	System Planning	1,450	1,290	160
18	561	Load Dispatching	1,107	1,182	(74)
19	562	Transmission Station Expense	658	782	(124)
20	563R-1	Transmission Line Maintenance	179	127	53
21	563R-2	Transmission ROW Maintenance	264	472	(207)
22	565	Wheeling	4,050	4,003	47
23	567	Rents	3,115	3,100	15
24	583R-1	Distribution Line Maintenance	2,926	3,263	(337)
25	583R-2	Distribution ROW Maintenance	2,153	1,741	412
26	586	Meter Expenses	986	999	(14)
27	592	Distribution Station Expense	1,273	1,304	(31)
28	596	Street Lighting	81	96	(16)
29	598	Other Plant	297	353	(55)
30			19,306	19,596	(290)
31					
32		CUSTOMER SERVICE			
33	901	Supervision & Administration	1,224	831	393
34	902	Meter Reading	1,791	1,763	28
35	903	Customer Billing	615	669	(54)
36	904	Credit & Collections	639	625	13
37	910	Customer Assistance	2,202	2,240	(38)
38			6,471	6,129	343

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont’d

FOR THE YEAR ENDING DECEMBER 31, 2010

Acct.		2010	2009	Change
			($000s)	
	ADMINISTRATIVE AND GENERAL			
920	Salaries			
920	Executive & Senior Management	1,167	1,515	(348)
920	Legal	646	604	42
920	Human Resources	840	808	33
920	Finance & Accounting	1,037	1,068	(31)
921	Information Services	997	1,043	(46)
921	Materials Management	214	184	30
	Other	256	252	4
		5,157	5,474	(317)
921	Expenses			
921	Executive & Senior Management	116	68	47
921	Legal	160	242	(83)
921	Human Resources	119	144	(25)
921	Finance & Accounting	128	115	13
922	Information Services	672	696	(24)
922	Materials Management	132	18	113
	Other	477	446	31
		1,803	1,730	73
923	Special Services	1,170	767	404
924	Insurance	676	705	(29)
932	Maintenance to General Plant	1,859	1,802	57
933	Transportation Equipment Expenses	373	658	(285)
		4,078	3,931	147
	TOTAL	121,889	120,137	1,752
Less:	Wheeling	(4,050)	(4,003)	(47)
	Power Purchases	(71,964)	(70,776)	(1,188)
	Water Fees	(9,256)	(8,656)	(600)
O&M	Expense per Financial Statements	**36,619**	**36,702**	**(83)**
Add:	Capitalized Overhead	**9,529**	**9,315**	**214**
Gross O&M		**46,148**	**46,017**	**131**

Note: Minor differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2010

	($000s)	
Amortization of Prior Year Incentives		
Amortization of 2008 Incentives	(322)	
Amortization of 2009 Incentives	(2,368)	
Total Amortization of Prior Year Incentives		(2,690)
Current Year Preliminary Flow Through Adjustments		
Preliminary Interest Expense	918	
Pope & Talbot Bad Debt Recovery	88	
2009 Cost of Removal Tax Savings	705	
HST Savings	54	
2010 Cost of Removal Tax Savings	364	
Total 2010 Flow Through Adjustments	2,129	
Current Year Preliminary ROE Incentive Adjustments		
Preliminary ROE Incentive	(449)	
Total Regulatory Incentive Adjustments		1,681
Current Year True-up to Actual (1)		380
Incentive Adjustments per Income Statement		(629)

(1) *A provision for true-up of incentives of $380,000 was recorded in 2010. This true-up from preliminary to final incentives for 2010 will flow through to 2012 Revenue Requirements.*

Note: Minor differences due to rounding.

SUMMARY OF PRELIMINARY INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2010

2010 Flow Through Adjustments	Approved	Forecast	Variance	Income Tax Shield ($000s)	After Tax Amount	Customer Share	Flow Through Adjustment
1 Interest Expense	36,782	35,498	1,284	366	918	100%	918
2 Pope & Talbot Bad Debt Recovery	-	(123)	123	35	88	100%	88
3 2009 Cost of Removal Tax Savings	-	(705)	705	-	705	100%	705
4 HST Savings	-	(76)	76	22	54	100%	54
5 2010 Cost of Removal Tax Savings	-	(364)	364	-	364	100%	364
6 Flow Through Adjustment							**2,129**

2010 ROE Incentive Adjustment	Approved	Forecast	Variance ($000s)	Customer Share	ROE Incentive Adjustment
7 Net Income for ROE Incentive	38,615	37,718	897	50%	**(449)**
8 Common Equity	390,046	378,300			
9 Allowed ROE	9.90%	9.97%	0.07%	50%	0.04%

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2010

		Normalized 2009	Decision 2010	Actual 2010	Normalized 2010	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	71,216	80,803	77,975	79,650	(1,153)
2	Deduct:					
3	Interest Expense	33,411	36,781	35,138	35,138	(1,644)
4	ACCOUNTING INCOME	37,806	44,021	42,837	44,512	491
5						
6	Deductions:					
7	Capital Cost Allowance	50,764	54,511	52,849	52,849	(1,663)
8	Capitalized Overhead	9,315	9,529	9,529	9,529	-
9	Incentive & Revenue Deferrals	(2,014)	2,690	629	629	(2,061)
10	Financing Fees	910	681	597	597	(84)
11	All Other (net effect)	1,048	419	3,020	3,020	2,601
12		60,023	67,830	66,624	66,624	(1,207)
13						
14	Additions:					
15	Amortization of Deferred Charges	2,521	3,742	3,695	3,695	(48)
16	Depreciation	34,855	38,286	38,075	38,075	(210)
17		37,376	42,028	41,771	41,770	(258)
18						
19	TAXABLE INCOME	15,158	18,219	17,984	19,658	1,440
20						
21	Tax Rate	30.00%	28.50%	28.50%	28.50%	0.00%
22						
23	Taxes	4,548	5,192	5,125	5,603	410
24	Investment Tax Credit	-	-	(27)	-	-
25	Tax Payable	4,548	5,192	5,098	5,603	410
26	Prior Years' (Overprovisions)/Underprovisions	(487)	-	(738)	(738)	(738)
27	Deferred Charges Tax Effect	256	214	184	184	(31)
28						
29	REGULATORY TAX PROVISION	4,316	5,407	4,544	5,048	(358)

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2010

			Normalized 2009	Decision 2010	Actual 2010	Normalized 2010	Change From Decision
					($000s)		
1	Share Capital		160,122	193,000	170,122	170,122	(22,878)
2	Retained Earnings		194,414	196,269	215,131	213,403	17,134
3							
4	COMMON EQUITY - OPENING BALANCE		354,536	389,269	385,253	383,525	(5,744)
5							
6	Less:	Common Dividends	(14,500)	(15,000)	(15,000)	(15,000)	-
7							
8	Add:	Net Income	33,489	38,614	38,293	39,464	850
9		Share Adjustment	-	-	-	-	-
10		Shares Issued	10,000	30,000	10,000	10,000	(20,000)
11							
12	COMMON EQUITY - CLOSING BALANCE		383,525	442,883	418,546	417,989	(24,894)
13							
14	SIMPLE AVERAGE		369,030	416,076	401,899	400,757	(15,319)
15							
16	Adjustment for Shares Issued		(3,726)	(6,164)	(4,973)	(4,973)	1,192
17	Deemed Equity Adjustment		-	(19,867)	-	-	19,867
18							
19	COMMON EQUITY - AVERAGE		365,304	390,045	396,927	395,785	5,740

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2010

		Normalized 2009	Decision 2010	Actual 2010	Normalized 2010	Change From Decision
				($000s)		
1	Secured and Senior Unsecured Debt	527,002	560,959	552,603	552,603	(8,356)
2	Proportion	60.66%	57.53%	58.42%	58.42%	0.90%
3	Embedded Cost	6.33%	6.22%	6.18%	6.18%	-0.03%
4	Cost Component	3.84%	3.58%	3.61%	3.61%	0.04%
5	Return	33,363	34,880	34,174	34,174	(706)
6						
7	Short Term Debt	(24,722)	24,110	(3,686)	(3,686)	(27,795)
8	Proportion	-2.85%	2.47%	-0.39%	-0.39%	-2.86%
9	Embedded Cost	-0.19%	7.89%	-26.15%	-26.15%	-34.03%
10	Cost Component	0.01%	0.20%	0.10%	0.10%	-0.09%
11	Return (including fees)	48	1,902	964	964	(938)
12						
13						
14	Common Equity	365,304	390,046	396,927	395,785	5,739
15	Proportion	42.11%	40.00%	41.97%	41.90%	1.90%
16	Embedded Cost	9.17%	9.90%	9.65%	9.97%	0.07%
17	Cost Component	3.86%	3.96%	4.05%	4.18%	0.22%
18	Return	33,489	38,615	38,293	39,464	849
19						
20	TOTAL CAPITALIZATION	867,584	975,114	945,844	944,701	(30,413)
21	RATE BASE	867,683	975,114	945,637	945,637	(29,478)
22						
23	Earned Return	66,900	75,396	73,430	74,602	(793)
24						
25	RETURN ON CAPITAL	7.71%	7.73%	7.76%	7.90%	0.16%
26	RETURN ON RATE BASE	7.71%	7.73%	7.77%	7.89%	0.16%

Note: Minor differences due to rounding.

2011 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2011

Line	Account		Reference	Actual 2010	Decision 2011	Actual 2011	Change from Decision
				($000s)			
1	101	Plant in Service, January 1	**p. 3**	1,273,476	1,417,415	1,403,617	(13,798)
2		Net Additions	**p. 6**	130,141	147,367	128,214	(19,153)
3		Plant in Service, December 31		1,403,617	1,564,782	1,531,831	(32,951)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	**p. 7**	7,213	5,444	7,488	2,044
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	**p. 11**	16,698	24,984	13,157	(11,827)
9							
10				1,439,440	1,607,122	1,564,387	(42,735)
11		**Less:**					
12		Accumulated Depreciation					
13		and Amortization	**p. 12**	323,203	375,482	357,692	(17,790)
14	252	Contributions in Aid of Construction		93,763	100,504	95,551	(4,952)
15				416,967	475,986	453,243	(22,742)
16							
17		Depreciated Rate Base		1,022,473	1,131,136	1,111,144	(19,992)
18							
19		Prior Year Depreciated Utility Rate Base		915,158	1,024,361	1,022,473	(1,888)
20							
21		Mean Depreciated Utility Rate Base		968,815	1,077,748	1,066,808	(10,940)
22							
23		**Add:**					
24		Allowance for Working Capital	**p. 13**	5,756	5,599	4,954	(645)
25		Adjustment for Capital Additions	**p. 14**	(28,934)	9,894	(5,870)	(15,764)
26							
27		Mid-Year Utility Rate Base		945,637	1,093,241	1,065,892	(27,349)

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2011

Line	Account		December 31 2010	Additions	Retirements & Reclass	December 31 2011
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,609	184	-	12,793
3	332	Reservoirs, Dams & Waterways	26,644	705	-	27,349
4	333	Water Wheels, Turbines and Gen.	73,448	20,665	-	94,113
5	334	Accessory Equipment	32,934	6,649	(593)	38,990
6	335	Other Power Plant Equipment	41,642	255	-	41,897
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			189,525	28,458	(593)	217,390
9		**Transmission Plant**				
10	350	Land Rights	7,271	40	-	7,311
11	350.1	Land Rights - Clearing	6,236	40	-	6,276
12	353	Station Equipment	150,925	32,617	(2,068)	181,474
13	355	Poles Towers & Fixtures	89,033	2,845	(80)	91,799
14	356	Conductors and Devices	86,903	2,798	(80)	89,621
15	359	Roads and Trails	1,121	-	-	1,121
16			341,489	38,342	(2,228)	377,603
17		**Distribution Plant**				
18	360	Land Rights	2,689	200	-	2,889
19	360.1	Land Rights - Clearing	9,964	53	-	10,017
20	362	Station Equipment	199,086	26,346	(1,633)	223,800
21	364	Poles Towers & Fixtures	137,498	7,924	(183)	145,239
22	365	Conductors and Devices	224,957	12,265	(300)	236,922
23	368	Line Transformers	104,732	6,792	(729)	110,795
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,593	809	(300)	14,102
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,485	747	(23)	12,208
28			712,234	55,136	(3,168)	764,202
29		**General Plant**				
30	389	Land	12,093	63	-	12,157
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	27,045	1,345	-	28,390
33	391	Office Furniture & Equipment	5,729	173	-	5,902
34	391.1	Computer Equipment	62,875	6,452	(193)	69,134
35	392	Transportation Equipment	17,755	3,509	(264)	21,000
36	394	Tools and Work Equipment	11,296	492	(4)	11,784
37	397	Communication Structures and Equipment	23,238	694	-	23,932
38			160,368	12,728	(461)	172,635
39						
40	101	**Plant in Service**	1,403,617	134,663	(6,450)	1,531,831
41	107.1	Plant under construction not subject				
42		to AFUDC	7,213			7,488
43	107.2	Plant under construction				
44		subject to AFUDC	50,769			4,197
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,473,511			1,555,427

Note: Minor differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2011

		CWIP Dec. 31, 2010	Actual Expenditures	CWIP Dec. 31, 2011	Additions to Plant in Service
			($000s)		
1	**Hydraulic Production**				
2	2011 Provincial Sales Tax (PST) Refund	-	(145)	-	(145)
3	South Slocan Plant Automation	-	208	208	-
4	South Slocan Fire Panel	-	269	269	-
5	Upper Bonnington Spillgate Rebuild / Upgrade	3	40	43	-
6	Lower Bonnington Power House Windows	8	244	252	-
7	All Plants Minor Sustainment	-	469	239	231
8	Lower & Upper Bonnington Communication Network	343	48	-	390
9	South Slocan Unit 1 Life Extension	-	44	-	44
10	All Plants Station Service	78	927	834	171
11	South Slocan Head Gate Hoist, Control, Wire Rope Upgrade/Replacement	-	37	-	37
12	Corra Linn Unit 1 Life Extension	13,010	2,990	-	16,000
13	Corra Linn Unit 2 Life Extension	3,265	12,090	497	14,859
14	Upper Bonnington Extension Trash Rack Gantry Replacement	204	165	-	369
15	South Slocan Domestic Water Supply Ph.3	86	61	-	147
16	Lower & Upper Bonnington Plant Totalizer Upgrade	-	93	49	44
17	Queen's Bay Level Gauge Building Ph.1	18	3	21	-
18		**17,015**	**17,543**	**2,411**	**32,147**
19	**Transmission Plant**				
20	Ellison to Sexsmith Transmission Tie	-	638	638	-
21	Okanagan Transmission Reinforcement	32,744	12,821	506	45,060
22	Benvoulin Distribution Source	-	993	-	993
23	Huth Bus Reconfiguration	241	3,612	-	3,853
24	Capitalized Inventory	5,333	727	6,060	-
25	Recreation Capacity Increase Stages 1,2,3	-	(21)	-	(21)
26	30 Line Conversion Slocan & Coffee Creek Substations	-	314	-	314
27	Transmission Sustainment	84	2,477	-	2,561
28	Station Sustainment	563	5,223	370	5,416
29		**38,965**	**26,786**	**7,574**	**58,177**
30	**Distribution Plant**				
31	New Connects System Wide	-	16,409	-	16,409
32	Distribution Unplanned Growth Projects	-	981	-	981
33	Small Growth Projects	-	685	-	685
34	Distribution Sustainment	108	8,359	12	8,455
35		**108**	**26,434**	**12**	**26,530**
36	**General Plant**				
37	Distribution Substation Automation	579	2,162	-	2,741
38	Protection, Harmonic Remediation,Communication & Rehabilitation	192	1,975	-	2,167
39	Mandatory Reliability Standards Compliance	738	872	-	1,610
40	Vehicles	386	2,664	-	3,050
41	Metering	-	316	-	316
42	Information Systems	-	4,829	-	4,829
43	Telecommunications	-	315	-	315
44	Buildings	-	1,287	-	1,287
45	Kootenay Long Term Facility Strategy	-	433	433	-
46	Okanagan Long Term Solution	-	190	190	-
47	PCB Environmental Compliance	-	1,718	1,064	654
48	Furniture & Fixtures	-	230	-	230
49	Tools & Equipment	-	609	-	609
50		**1,895**	**17,602**	**1,688**	**17,808**
51	**TOTAL**	**57,982**	**88,365**	**11,685**	**134,663**
52	Less Closing CWIP subject to AFUDC	**(50,769)**		**(4,197)**	
53	TOTAL CWIP not subject to AFUDC	**7,213**		**7,488**	

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2011

		Balance at Dec. 31, 2010	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2011
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	20,961	5,917	-	(1,859)	25,020
3	Tax Impact	(12,528)	(1,568)	-	493	(13,603)
4		**8,433**	**4,349**	**-**	**(1,366)**	**11,417**
5	**Deferred Regulatory Expense**					
6	2009 Flow-through and ROE Sharing Mechanism Adjustments	(1,090)	-	1,090	-	-
7	2010 Flow-through and ROE Sharing Mechanism Adjustments	(2,061)	-	1,681	-	(380)
8	2011 Flow-through and ROE Sharing Mechanism Adjustments	-	(6,887)	-	-	(6,887)
9	2010 Revenue Requirements	75	-	-	(75)	-
10	Tax Impact	(22)	-	-	22	-
11	2011 Revenue Requirements	35	41	-	-	76
12	Tax Impact	(10)	(11)	-	-	(21)
13	Renewal of BCH Power Purchase Agreement	109	29	-	-	138
14	Tax Impact	(33)	(8)	-	-	(41)
15	FortisBC Energy (Terasen Gas) ROE and Capital Structure Application	76	-	-	(76)	-
16	Tax Impact	(23)	-	-	23	-
17	Section 5 Provincial Transmission Inquiry	90	-	-	(90)	-
18	Tax Impact	(27)	-	-	27	-
19	BC Hydro Waneta Transaction Application	284	-	-	(95)	189
20	Tax Impact	(85)	-	-	28	(57)
21	BC Hydro Amendment to 3808 (PPA) Proceedings	76	-	-	(38)	38
22	Tax Impact	(23)	-	-	12	(12)
23	2009 Cost of Service Analysis and Rate Design Application	1,708	418	-	(531)	1,595
24	Tax Impact	(503)	(111)	-	153	(460)
25	Shaw Application for Transmission Facility Access	288	80	-	-	367
26	Tax Impact	(82)	(21)	-	-	(103)
27	Tariff Amendment - Adaptive Street Lighting	3	-	(3)	-	-
28	Tax Impact	(1)	-	1	-	-
29	Residential Inclining Block Rate and Industrial Stepped Rate Application	-	189	-	-	189
30	Tax Impact	-	(50)	-	-	(50)
31	Implementation of New Rate Structures	-	22	-	-	22
32	Tax Impact	-	(6)	-	-	(6)
33	Irrigation Rate Payer Consultation and Load Research	-	18	-	-	18
34	Tax Impact	-	(5)	-	-	(5)
35	2012 Integrated System Plan and 2012 - 2013 Revenue Requirements	75	1,444	-	-	1,519
36	Tax Impact	(21)	(418)	-	-	(439)
37	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	360	187	-	(120)	427
38	Tax Impact	(103)	(49)	-	34	(118)
39		**(903)**	**(5,138)**	**2,768**	**(727)**	**(3,999)**
40						
41	**Preliminary and Investigative Charges**	**2,435**	**1,126**	**(798)**	**-**	**2,764**
42						
43	**Other Deferred Charges and Credits**					
44	Trail Office Lease Costs	155	-	-	(12)	143
45	Trail Office Rental to SD20	(729)	-	(57)	-	(786)
46	Prepaid Pension Costs	7,448	(468)	-	-	6,979
47	Tax Impact	(757)	124	-	-	(633)
48	Other Post Employment Benefits (OPEB)	(10,321)	(3,053)	-	-	(13,374)
49	Tax Impact	3,211	809	-	-	4,020
50	Resource Plan	789	(789)	-	-	-
51	Tax Impact	(244)	244	-	-	-
52	Revenue Protection	221	219	-	(221)	219
53	Tax Impact	(63)	(58)	-	63	(58)
54	Demand Side Management Study	259	-	-	(86)	173
55	Tax Impact	(75)	-	-	25	(50)
56	Princeton Light and Power Computer Software	40	-	-	(23)	17
57	Princeton Light and Power Deferred Pension Credit	(46)	-	-	12	(35)
58	Right of Way Reclamation (Pine Beetle Kill)	2,006	-	-	(251)	1,755
59	Tax Impact	(622)	-	-	78	(544)
60	International Financial Reporting Standards	214	-	-	(214)	-
61	Tax Impact	(61)	-	-	61	-
62	Right of Way Encroachment Litigation	91	-	-	-	91
63	Tax Impact	(28)	-	-	-	(28)
64	Joint Pole Use Audit 2008	93	-	-	(31)	62
65	Tax Impact	(28)	-	-	9	(19)
66	Mandatory Reliability Standards	848	203	-	-	1,051
67	Tax Impact	(242)	(54)	-	-	(296)
68	Harmonized Sales Tax Implementation Project	222	-	-	(222)	-
69	Tax Impact	(63)	-	-	63	-
70	Pope & Talbot Litigation	23	-	-	(23)	-
71	Tax Impact	(7)	-	-	7	-
72	US Generally Accepted Accounting Principles	-	712	-	-	712
73	Tax Impact	-	(189)	-	-	(189)
74		**2,333**	**(2,300)**	**(57)**	**(766)**	**(790)**

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

		Balance at Dec. 31, 2010	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2011
				($000s)		
75	**Deferred Debt Issue Costs**					
76	Series F	70	-	-	(39)	31
77	Series G	93	-	-	(7)	86
78	Series H	67	-	-	(13)	54
79	Series I	157	-	-	(14)	142
80	Series 04-1	858	-	-	(219)	638
81	Tax Impact	(61)	-	-	16	(45)
82	Series 05-1	1,032	-	-	(42)	990
83	Tax Impact	(376)	-	-	15	(361)
84	Series 07-1	1,153	-	-	(32)	1,121
85	Tax Impact	(320)	(88)	-	9	(400)
86	MTN - 2009	957	-	-	(34)	924
87	Tax Impact	(118)	(59)	-	4	(173)
88	MTN - 2010	941	(74)	-	(22)	846
89	Tax Impact	(54)	(37)	-	1	(89)
90		**4,399**	**(258)**	**-**	**(377)**	**3,765**
91						
92	**TOTAL DEFERRED CHARGES (RATE BASE)**	**16,698**	**(2,220)**	**1,914**	**(3,236)**	**13,157**
93	**Deferred Charges (Non Rate Base)**					
94	Advanced Metering Infrastructure (AMI) Costs	920	1,198	-	-	2,118
95	**GRAND TOTAL DEFERRED CHARGES**	**17,618**	**(1,022)**	**1,914**	**(3,236)**	**15,275**

Note: Minor differences due to rounding.

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Row 94: Pursuant to the Negotiated Settlement Agreements for the 2010 and 2011 Revenue Requirements, AMI costs were collected in a non-rate base deferral account that collected AFUDC.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2011

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2010	Approved Deprec. Rate	Asset Balance Dec. 31, 2010	Depreciation Expense Dec. 31, 2011	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2011
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(570)	2.6%	962	25	-	(545)
2	331	Structures and Improvements	5,343	1.2%	12,609	151	(38)	5,456
3	332	Reservoirs, Dams and Waterways	5,535	1.7%	26,644	453	(48)	5,940
4	333	Water Wheels, Turbines & Generators	1,608	2.2%	73,448	1,616	(459)	2,765
5	334	Accessory Electrical Equipment	7,613	2.4%	32,934	790	(829)	7,574
6	335	Other Power Plant Equipment	9,219	2.3%	41,642	958	-	10,177
7	336	Roads, Railroads, and Bridges	486	1.4%	1,287	18	-	504
8			29,233	2.1%	189,525	4,011	(1,374)	31,870
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	7,271	-	-	(62)
11	350.1	Land Rights - Clearing	2,062	1.6%	6,236	104	-	2,166
12	353	Station Equipment	2,323	3.0%	150,925	1,900	(2,385)	1,839
13	355	Poles, Towers & Fixtures	8,318	3.0%	89,033	2,671	(1,020)	9,969
14	356	Conductors and Devices	4,651	3.0%	86,903	2,607	(1,005)	6,253
15	359	Roads and Trails	89	2.9%	1,121	33	-	121
16			17,381	2.1%	341,489	7,316	(4,409)	20,287
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	2,689	-	-	(868)
19	360.1	Land Rights - Clearing	(28)	2.1%	9,964	209	-	181
20	362	Station Equipment	68,899	3.0%	199,086	8,579	(1,921)	75,557
21	364	Poles, Towers & Fixtures	40,730	3.0%	137,498	4,125	(747)	44,109
22	365	Conductors and Devices	62,546	3.0%	224,957	6,749	(1,204)	68,091
23	368	Line Transformers	20,076	2.9%	104,732	3,049	(1,267)	21,858
24	369	Services	6,511	0.0%	7,292	36	-	6,547
25	370	Meters	5,294	3.5%	13,593	483	(216)	5,561
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,464	2.4%	11,485	278	(104)	3,638
28			203,212	3.3%	712,234	23,507	(5,459)	221,261
29		General Plant						
30	389	Land	897	0.0%	12,093	-	-	897
31	390	Structures - Frame & Iron	536	0.8%	337	3	-	539
32	390.1	Structures - Masonry	4,194	3.0%	22,248	667	-	4,861
33	391	Office Furniture & Equipment	4,241	7.5%	5,729	430	-	4,671
34	391.1	Computer Equipment	41,529	10.6%	62,875	6,665	(193)	48,001
35	392	Transportation Equipment	1,484	0.4%	17,755	71	(261)	1,293
36	394	Tools and Work Equipment	7,211	9.5%	11,296	1,073	(4)	8,280
37	397	Communication Structures and Equipment	7,288	6.0%	23,238	1,394	(16)	8,666
38			67,381	6.6%	155,572	10,303	(474)	77,210
39								
40	108	Total Accumulated Depreciation	317,207	3.2%	1,398,820	45,137	(11,717)	350,628
41								
42		Deduct - Portion of CIAC Depreciated				(4,092)		
43								
44	403	Depreciation Expense				41,045		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,024		11,912	186		5,210
48	390.1	Leasehold Improvements	2,526		4,796	571		3,097
49		Rate Stabilization Adjustment	(1,554)	10.00%		311		(1,243)
50		Total Accumulated Amortization	5,996			1,068		7,064
51								
52		Accumulated Amortization per						
53		Balance Sheet	323,203			42,113		357,692

Note: Minor differences due to rounding.

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2011

	Lag Days Calculation	Lag (Lead) Days	2011 Actual ($000s)	2011 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	50.5	277,090	13,993	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	3,709	99	
5	Contract Revenue	44.3	1,826	81	
6	Miscellaneous Revenue	31.8	1,791	57	
7	Investment Income	15.0	180	3	
8			284,596	14,232	50.0
9					
10	**Expenses**				
11	Power Purchases	42.2	71,519	3,018	
12	Wheeling	40.2	4,281	172	
13	Water Fees	(1.0)	9,047	(9)	
14	*Operating Labour:*				
15	Salaries & Wages	5.3	13,463	71	
16	Employee Benefits	13.2	10,501	139	
17	Contracted Manpower	50.6	8,304	420	
18	Property Tax	2.6	13,408	35	
19	Rental of T&D Facilities	47.8	3,033	145	
20	Office Lease - Kelowna	(15.2)	827	(13)	
21	Office Lease - Trail	91.3	1,212	111	
22	Materials	45.6	4,407	201	
23	Insurance	(182.5)	550	(100)	
24	Income Tax	15.2	9,417	143	
25	Interest	82.9	38,893	3,224	
26			188,863	7,557	40.0
27					
28	**Net Lag/(Lead) Days**				**10.0**
29					
30					
31	**Working Capital Allowance**			($000s)	
32					
33	**Lead-Lag Study Allowance:**				
34	Net Lag Days/365 times Expenses				5,173
35					
36	**Add Funds Unavailable:**				
37	Average Customer Loans (related to energy management)			2,762	
38	Average Employee Loans			371	
39	Average of Uncollectable Accounts			1,024	
40	Average Inventory (forecast monthly average investment)			539	
41					4,696
42	**Less Funds Available:**				
43	Average Customer Deposits			4,089	
44	Average HST			825	
45					4,915
46					
47	**2011 ALLOWANCE FOR WORKING CAPITAL**				**4,954**

Note: Minor differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2011

		Additions to Plant in Service * ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	1,061	11.5	1,017
2	February	2,605	10.5	2,279
3	March	41,220	9.5	32,632
4	April	11,626	8.5	8,235
5	May	2,676	7.5	1,672
6	June	3,382	6.5	1,832
7	July	2,527	5.5	1,158
8	August	10,285	4.5	3,857
9	September	6,009	3.5	1,753
10	October	8,548	2.5	1,781
11	November	8,241	1.5	1,030
12	December	30,603	0.5	1,275
13	**Total**	**128,783**		**58,522**
14	Less Simple Average			64,391
15	Adjustment to Capital Additions			**(5,870)**

16 ** Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:*

17	Gross Plant in Service Additions	134,663
18	CIAC	(5,880)
19	Net Capital Additions	**128,783**

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2010	Decision 2011	Actual 2011	Normalized 2011	Change from Decision
1	SALES VOLUME (GWh)	3,094	3,162	3,143	3,129	(32)
2						
3				($000s)		
4	ELECTRICITY SALES REVENUE	250,235	278,783	277,090	275,898	(2,886)
5						
6	EXPENSES					
7	Power Purchases	73,733	81,212	71,519	70,458	(10,754)
8	Water Fees	9,256	9,381	9,047	9,047	(334)
9	Wheeling	4,050	3,338	4,281	4,281	943
10	Net O&M Expense	36,619	43,108	42,299	42,299	(809)
11	Property Tax	12,238	13,940	13,408	13,408	(532)
12	Depreciation and Amortization	41,771	45,498	45,349	45,349	(149)
13	Other Income	(6,453)	(5,455)	(7,506)	(7,506)	(2,051)
14	Incentive Adjustments	(629)	(2,770)	4,116	4,116	6,886
15	UTILITY INCOME BEFORE TAX	79,650	90,531	94,577	94,446	3,915
16	Less:					
17	INCOME TAXES	5,048	6,733	9,417	9,382	2,649
18						
19	EARNED RETURN	74,602	83,798	85,160	85,064	1,266
20	RETURN ON RATE BASE					
21	Utility Rate Base	945,637	1,093,241	1,065,892	1,065,892	(27,349)
22	Return on Rate Base	7.89%	7.67%	7.99%	7.98%	0.32%

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

Line	Account		2011	2010	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	666	584	82
3	536	Water Fees	9,047	9,256	(209)
4	542	Structures	697	651	47
5	543	Dams & Waterways	270	204	65
6	544	Electric Plant	534	627	(93)
7	545	Other Plant	271	134	137
8			11,485	11,456	29
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	71,519	71,964	(446)
12	556	System Control	1,805	1,653	152
13			73,324	73,617	(293)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,634	768	866
17	560R-2	System Planning	2,148	1,450	699
18	561	Load Dispatching	1,193	1,107	86
19	562	Transmission Station Expense	902	658	245
20	563R-1	Transmission Line Maintenance	570	179	391
21	563R-2	Transmission ROW Maintenance	1,218	264	954
22	565	Wheeling	4,281	4,050	231
23	567	Rents	3,033	3,115	(82)
24	583R-1	Distribution Line Maintenance	3,304	2,926	379
25	583R-2	Distribution ROW Maintenance	3,684	2,153	1,531
26	586	Meter Expenses	1,030	986	44
27	592	Distribution Station Expense	1,313	1,273	41
28	596	Street Lighting	78	81	(3)
29	598	Other Plant	249	297	(48)
30			24,639	19,306	5,333
31					
32		CUSTOMER SERVICE			
33	901	Supervision & Administration	1,128	1,224	(95)
34	902	Meter Reading	2,030	1,791	238
35	903	Customer Billing	646	615	30
36	904	Credit & Collections	683	639	45
37	910	Customer Assistance	2,462	2,202	259
38			6,949	6,471	478

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

Line	Account	2011	2010	Change
			($000s)	
39				
40	ADMINISTRATIVE AND GENERAL			
41	920 Salaries			
42	920.1 Executive & Senior Management	1,371	1,167	203
43	920.2 Legal	687	646	42
44	920.3 Human Resources	788	840	(52)
45	920.4 Finance & Accounting	1,065	1,037	28
46	920.6 Information Services	903	997	(94)
47	920.7 Materials Management	184	214	(30)
48	Other	288	256	32
49		5,287	5,157	129
50				
51	921 Expenses			
52	921.1 Executive & Senior Management	142	116	26
53	921.2 Legal	87	160	(73)
54	921.3 Human Resources	182	119	63
55	921.4 Finance & Accounting	80	128	(49)
56	921.6 Information Services	638	672	(34)
57	921.7 Materials Management	(3)	132	(134)
58	Other	390	477	(87)
59		1,516	1,803	(287)
60				
61	923 Special Services	966	1,170	(204)
62	924 Insurance	550	676	(126)
63	932 Maintenance to General Plant	1,719	1,859	(140)
64	933 Transportation Equipment Expenses	712	373	339
65		3,947	4,078	(131)
66				
67	TOTAL	127,146	121,889	5,257
68				
69				
70				
71	Less: Wheeling	(4,281)	(4,050)	(231)
72	Power Purchases	(71,519)	(71,964)	446
73	Water Fees	(9,047)	(9,256)	209
74	O & M Expense per Financial Statements	**42,299**	**36,619**	**5,680**
75				
76	Add: Capitalized Overhead	**10,777**	**9,529**	**1,248**
77				
78	**Gross O&M**	**53,076**	**46,148**	**6,928**

Note: Minor differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2011

		($000s)	
1	Amortization of Prior Year Incentives		
2	Amortization of 2009 Incentives	(1,090)	
3	Amortization of 2010 Incentives	(1,681)	
4			
5	Total Amortization of Prior Year Incentives		(2,770)
6			
7	Current Year Preliminary Flow Through Adjustments		
8	Interest Expense	835	
9	Transmission Pole Rental Revenue	59	
10	Fibre Leasing Revenue	175	
11	Water Fees Rate Reduction	223	
12	Celgar Tariff Difference	1,990	
13	Total 2011 Flow Through Adjustments	3,281	
14			
15	Current Year Preliminary ROE Incentive Adjustments		
16	Preliminary ROE Incentive	2,559	
17			
18			
19	Total Regulatory Incentive Adjustments		5,840
20			
21			
22	Current Year True-up to Actual [1]		1,047
23			
24			
25	Incentive Adjustments per Income Statement		4,116

[1] *A provision for true-up of incentives of $1,047,000 was recorded in 2011, post 2012 - 2013 Revenue Requirements, Evidentiary Update Filing. This true-up from final incentives for 2010 will flow through to 2014 Revenue Requirements.*

Note: Minor differences due to rounding.

SUMMARY OF PRELIMINARY INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

	2011 Flow Through Adjustments	Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
					($000s)			
1	Interest Expense	40,505	39,369	1,136	301	835	100%	835
2	Transmission Pole Rental Revenue	-	-	80	21	59	100%	59
3	Fibre Leasing Revenue	-	-	237	63	175	100%	175
4	Water Fees Rate Reduction	-	-	303	80	223	100%	223
5	Celgar Tariff Difference	-	-	2,708	718	1,990	100%	1,990
6	Flow-Through Adjustment							3,281

	2011 ROE Incentive Adjustment		Before Incentive				After Incentive
		Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment	Forecast
			($000s)				($000s)
7	Net Income for ROE Incentive	43,292	48,410	(5,118)	50%	(2,559)	45,851
8	Common Equity	437,296	434,751				433,472
9	Allowed ROE	9.90%	11.14%	1.24%	50%		10.58%

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

		Normalized 2010	Decision 2011	Actual 2011	Normalized 2011	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	79,650	90,531	94,577	94,446	3,915
2	Deduct:					
3	Interest Expense	35,138	40,505	38,893	38,893	(1,613)
4	ACCOUNTING INCOME	44,512	50,025	55,684	55,553	5,528
5						
6	Deductions:					
7	Capital Cost Allowance	52,849	56,903	57,441	57,441	538
8	Capitalized Overhead	9,529	10,777	10,777	10,777	-
9	Incentive & Revenue Deferrals	629	2,770	(4,116)	(4,116)	(6,886)
10	Financing Fees	597	619	587	587	(33)
11	All Other (net effect)	3,020	(217)	879	879	1,096
12		66,624	70,852	65,568	65,568	(5,284)
13						
14	Additions:					
15	Amortization of Deferred Charges	3,695	3,297	3,236	3,236	(61)
16	Depreciation	38,075	42,201	42,113	42,113	(88)
17		41,770	45,498	45,349	45,349	(149)
18						
19	TAXABLE INCOME	19,658	24,671	35,465	35,334	10,663
20						
21	Tax Rate	28.50%	26.50%	26.50%	26.50%	0.00%
22						
23	Taxes	5,603	6,538	9,398	9,363	2,826
24	Investment Tax Credit	-	-	(39)	(39)	(39)
25	Tax Payable	5,603	6,538	9,360	9,325	2,787
26	Prior Years' Overprovisions/(Underprovisions)	(738)	-	(127)	(127)	(127)
27	Deferred Charges Tax Effect	184	195	184	184	(11)
28						
29	REGULATORY TAX PROVISION	5,048	6,733	9,417	9,382	2,649

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2011

			Normalized 2010	Decision 2011	Actual 2011	Normalized 2011	Change From Decision
					($000s)		
1	Share Capital		170,122	213,000	180,122	180,122	(32,878)
2	Retained Earnings		213,403	220,420	238,424	238,424	18,004
3							
4	COMMON EQUITY - OPENING BALANCE		383,525	433,420	418,546	418,546	(14,874)
5							
6	Less:	Common Dividends	(15,000)	(16,000)	(16,000)	(16,000)	-
7	Add:	Net Income	39,464	43,292	46,268	46,171	2,879
8		Share Adjustment	-		-	-	-
9		Shares Issued	10,000	10,000	-	-	(10,000)
10							
11	COMMON EQUITY - CLOSING BALANCE		417,989	470,712	448,813	448,717	(21,995)
12							
13	SIMPLE AVERAGE		400,757	452,066	433,680	433,631	(18,435)
14							
15	Adjustment for Shares Issued		(4,973)	(3,685)	-	-	3,685
16	Deemed Equity Adjustment		-	(11,085)	-	-	11,085
17							
18	COMMON EQUITY - AVERAGE		395,785	437,296	433,680	433,631	(3,665)

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2011

		Normalized 2010	Decision 2011	Actual 2011	Normalized 2011	Change From Decision
				($000s)		
1	Secured and Senior Unsecured Debt	552,603	650,000	640,000	640,000	(10,000)
2	Proportion	58.42%	59.46%	60.04%	60.04%	0.59%
3	Embedded Cost	6.18%	6.04%	6.04%	6.04%	0.00%
4	Cost Component	3.61%	3.59%	3.63%	3.63%	0.03%
5	Return	34,174	39,275	38,664	38,664	(610)
6						
7	Short Term Debt	(3,686)	5,945	(7,787)	(7,787)	(13,732)
8	Proportion	-0.39%	0.54%	-0.73%	-0.73%	-1.27%
9	Embedded Cost	-26.15%	20.71%	-2.93%	-2.93%	-23.64%
10	Cost Component	0.10%	0.11%	0.02%	0.02%	-0.09%
11	Return (including fees)	964	1,231	228	228	(1,003)
12						
13						
14	Common Equity	395,785	437,296	433,680	433,631	(3,665)
15	Proportion	41.90%	40.00%	40.69%	40.68%	0.68%
16	Embedded Cost	9.97%	9.90%	10.67%	10.65%	0.75%
17	Cost Component	4.18%	3.96%	4.34%	4.33%	0.37%
18	Return	39,464	43,292	46,268	46,171	2,879
19						
20	TOTAL CAPITALIZATION	944,701	1,093,241	1,065,892	1,065,844	(27,397)
21	RATE BASE	945,637	1,093,241	1,065,892	1,065,892	(27,349)
22						
23	Earned Return	74,602	83,798	85,160	85,064	1,266
24						
25	RETURN ON CAPITAL	7.90%	7.67%	7.99%	7.98%	0.32%
26	RETURN ON RATE BASE	7.89%	7.67%	7.99%	7.98%	0.32%

Note: Minor differences due to rounding.

2012 FINANCIAL SCHEDULES

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2012

Line	Account		Reference	Actual 2011	Decision 2012	Actual 2012	Change from Decision
				($000s)			
1	101	Plant in Service, January 1	p. 3	1,403,617	1,533,337	1,531,831	(1,506)
2		Net Additions	p. 4	128,214	80,704	58,074	(22,630)
3		Plant in Service, December 31		1,531,831	1,614,040	1,589,905	(24,136)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	p. 5	7,488	5,875	8,136	2,261
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 8	13,157	21,406	19,052	(2,354)
9							
10				1,564,387	1,653,233	1,629,005	(24,229)
11		**Less:**					
12		Accumulated Depreciation					
13		and Amortization	p. 10	357,692	383,067	395,823	12,755
14	252	Contributions in Aid of Construction		95,551	104,808	97,671	(7,137)
15				453,243	487,875	493,494	5,619
16							
17		Depreciated Rate Base		1,111,144	1,165,358	1,135,510	(29,847)
18							
19		Prior Year Depreciated Utility Rate Base		1,022,473	1,120,575	1,111,144	(9,432)
20							
21		Mean Depreciated Utility Rate Base		1,066,808	1,142,967	1,123,327	(19,640)
22							
23		**Add:**					
24		Allowance for Working Capital	p. 11	4,954	1,733	(1,264)	(2,997)
25		Deferred 2012 Opening Balance Adjustment[1]		-	(2,741)	(1,015)	1,727
26		Kettle Valley Adjustments[2]		-	(25,756)	(25,756)	-
27		Adjustment for Capital Additions	p. 12	(5,870)	(3,901)	(6,822)	(2,921)
28							
29		Mid-Year Utility Rate Base		1,065,892	1,112,302	1,088,470	(23,832)

[1] *Order No. G-110-12*

[2] *In compliance with BCUC Order G-73-12, the Kettle Valley Project year-end 2011 net book value of $25,756 is included in Plant in Service and has been removed from Rate Base by an adjustment in Line 26 above.*

Note: Minor differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2012

Line	Account		December 31 2011	Additions	Retirements & Reclass	December 31 2012
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,793	1,026	(13)	13,805
3	332	Reservoirs, Dams & Waterways	27,349	2,081	(73)	29,357
4	333	Water Wheels, Turbines & Gen.	94,113	1,387	(2)	95,497
5	334	Accessory Equipment	38,990	3,474	(447)	42,017
6	335	Other Power Plant Equipment	41,897	1,508	(380)	43,024
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			217,390	9,475	(916)	225,949
9		**Transmission Plant**				
10	350	Land Rights	7,311	1,397	-	8,708
11	350.1	Land Rights - Clearing	6,276	1,704	-	7,981
12	353	Station Equipment	181,474	(8,249)	(68)	173,158
13	355	Poles, Towers & Fixtures	91,799	2,234	(90)	93,943
14	356	Conductors and Devices	89,621	2,235	(105)	91,751
15	359	Roads and Trails	1,121	-	-	1,121
16			377,603	(678)	(263)	376,663
17		**Distribution Plant**				
18	360	Land Rights	2,889	394	-	3,283
19	360.1	Land Rights - Clearing	10,017	195	-	10,212
20	362	Station Equipment	223,800	18,934	(104)	242,630
21	364	Poles, Towers & Fixtures	145,239	7,785	(462)	152,562
22	365	Conductors and Devices	236,922	11,968	(376)	248,514
23	368	Line Transformers	110,795	5,579	(965)	115,409
24	369	Services	7,292	-	-	7,292
25	370	Meters	14,102	673	(514)	14,261
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	12,208	23	(57)	12,174
28			764,202	45,551	(2,479)	807,275
29		**General Plant**				
30	389	Land	12,157	(3,007)	-	9,150
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	28,390	1,698	-	30,087
33	391	Office Furniture & Equipment	5,902	113	-	6,015
34	391.1	Computer Equipment	69,134	4,776	(128)	73,783
35	392	Transportation Equipment	21,000	1,959	(781)	22,178
36	394	Tools and Work Equipment	11,784	531	(86)	12,229
37	397	Communication Structures and Equipment	23,932	2,307	-	26,239
38			172,635	8,377	(994)	180,018
39						
40	101	**Plant in Service**	1,531,831	62,725	(4,651)	1,589,904
41	107.1	Plant under construction not subject				
42		to AFUDC	7,488			8,136
43	107.2	Plant under construction				
44		subject to AFUDC	4,197			5,503
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,555,427			1,615,456

Note: Minor differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2012

		CWIP Dec. 31, 2011	Actual Expenditures	CWIP Dec. 31, 2012	Additions to Plant in Service
			($000s)		
1	**Hydraulic Production**				
2	South Slocan Plant Automation	208	68	-	276
3	All Plants Concrete & Structural Rehabilitation	-	269	144	125
4	Corra Linn Unit 3 Completion	-	281	-	281
5	Upper Bonnington Spillgate Rebuild	43	1,614	-	1,657
6	Lower Bonnington Power House Windows	252	463	-	715
7	All Plants Minor Sustaining Projects	239	773	33	979
8	Upper Bonnington Old Plant Various Unit Upgrades	-	217	(51)	268
9	Lower Bonnington, Upper Bonnington & Corra Linn Fire Panels	-	280	-	280
10	All Plants Upgrade Station Service Supply	834	1,217	-	2,051
11	Corra Linn Unit 1 Life Extension	-	46	-	46
12	Corra Linn Unit 2 Life Extension	497	2,600	428	2,668
13	South Slocan Fire Panel	269	24	-	293
14	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade	49	32	-	81
15	Queen's Bay Level Gauge Building Ph.1	21	3	25	-
16		**2,412**	**7,886**	**579**	**9,720**
17	**Transmission Plant**				
18	Ellison to Sexsmith Transmission Tie	638	125	763	-
19	Okanagan Transmission Reinforcement	506	3,825	-	4,331
20	Huth Split Bus	-	1,266	-	1,266
21	Capitalized Inventory & Transformers	6,060	247	6,307	-
22	Backbone Transport Technology Migration	-	28	28	-
23	Transmission Sustainment	1,064	10,237	2,665	8,637
24	Station Sustainment	369	3,197	155	3,411
25		**8,637**	**18,925**	**9,917**	**17,645**
26	**Distribution Plant**				
27	New Connects System Wide	-	15,665	-	15,665
28	Distribution Unplanned Growth Projects	-	777	-	777
29	Small Growth Projects	-	639	294	345
30	Distribution Sustainment	12	8,913	70	8,856
31		**12**	**25,994**	**364**	**25,642**
32	**General Plant**				
33	Distribution Substation Automation	-	37	-	37
34	Protection Upgrades	-	(403)	-	(403)
35	Communication Upgrades	-	388	-	388
36	Mandatory Reliability Standards Compliance	-	112	-	112
37	Buildings	-	1,536	-	1,536
38	Kootenay Long Term Facility Strategy	433	360	793	-
39	Okanagan Long Term Solution	190	48	238	-
40	Central Warehousing	-	1,634	1,634	-
41	Furniture & Fixtures	-	113	-	113
42	Fleet	-	1,959	-	1,959
43	Telecommunications	-	99	-	99
44	Infrastructure Sustainment	-	1,219	-	1,219
45	Desktop Infrastructure Sustainment	-	1,223	-	1,223
46	Applications Enhancements	-	1,267	-	1,267
47	Application Sustainment	-	1,192	-	1,192
48	PowerSense DSM Reporting Software	-	115	115	-
49	Meter	-	446	-	446
50	Tools	-	531	-	531
51		**623**	**11,876**	**2,780**	**9,719**
52					
53	**TOTAL**	**11,685**	**64,680**	**13,639**	**62,725**
54					
55	Less Closing CWIP subject to AFUDC	**(4,197)**		**(5,503)**	
56	TOTAL CWIP not subject to AFUDC	**7,488**		**8,136**	

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2012

		Balance at Jan 1, 2012	Additions and Transfers	Add Deferred Interest	Amortized / Transferred to Other Accounts ($000s)	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2012
	Deferral Accounts in Rate Base:							
1	**Demand Side Management**							
2	Demand Side Management Additions	25,020	6,975		-		(2,361)	29,633
3	Tax Impact	(13,603)	(1,744)		-		590	(14,756)
4		**11,417**	**5,231**	**-**	**-**	**-**	**(1,771)**	**14,877**
5	**Deferred Regulatory Expense**							
6	2010 Flow-Through and ROE Sharing Mechanism Adjustments	(380)	-	-	380	-	-	-
7	2011 Flow-Through and ROE Sharing Mechanism Adjustments	(6,887)	-	-	5,840	-	-	(1,046)
8	Implementation of New Rate Structures	22	-	-	-	-	(25)	(3)
9	Tax Impact	(6)	-	-	-	-	7	1
10	Residential Inclining Block Rate and Industrial Stepped Rate Application	189	75	-	-	-	(100)	163
11	Tax Impact	(50)	(19)	-	-	-	26	(42)
12	2011 Revenue Requirements	76	-	-	-	-	(75)	1
13	Tax Impact	(21)	-	-	-	-	21	(0.3)
14	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	427	212	-	-	-	(120)	519
15	Tax Impact	(118)	(53)	-	-	-	34	(137)
16	Cost of Service Analysis and Rate Design Application	1,594	50	-	-	-	(526)	1,118
17	Tax Impact	(460)	(12)	-	-	-	152	(321)
18	BC Hydro Amendment to 3808 (PPA) Proceedings	38	-	-	-	-	(38)	-
19	Tax Impact	(12)	-	-	-	-	12	-
20	BC Hydro Waneta Transaction Application	189	-	-	-	-	(95)	95
21	Tax Impact	(57)	-	-	-	-	28	(28)
22		**(5,454)**	**253**	**-**	**6,221**	**-**	**(699)**	**320**
23	**Other Deferred Charges and Credits**							
24	Trail Office Lease Costs	143	-	-	-	-	(12)	131
25	Trail Office Rental to SD#20	(786)	-	-	(65)	-	-	(851)
26	Revenue Protection	219	-	-	-	-	(235)	(16)
27	Tax Impact	(58)	-	-	-	-	62	4
28	Princeton Light and Power Computer Software	17	-	-	-	-	(10)	7
29	Princeton Light and Power Deferred Pension Credit	(35)	-	-	-	-	12	(23)
30	Right of Way Reclamation (Pine Beetle Kill)	1,755	-	-	-	-	(251)	1,504
31	Tax Impact	(544)	-	-	-	-	78	(466)
32	Demand Side Management Study	173	-	-	-	-	(86)	86
33	Tax Impact	(50)	-	-	-	-	25	(25)
34	US Generally Accepted Accounting Principles	712	(65)	-	-	-	(404)	243
35	Tax Impact	(189)	16	-	-	-	107	(65)
36	Joint Pole Use Audit 2008	62	-	-	-	-	(31)	31
37	Tax Impact	(19)	-	-	-	-	9	(9)
38		**1,400**	**(49)**	**-**	**(65)**	**-**	**(736)**	**550**
39	**Deferred Debt Issue Costs**							
40	Series F	31	-	-	-	-	(31)	-
41	Series G	86	-	-	-	-	(7)	78
42	Series H	54	-	-	-	-	(13)	41
43	Series I	142	-	-	-	-	(14)	128
44	Series 04-1	638	-	-	-	-	(219)	419
45	Tax Impact	(45)	-	-	-	-	16	(30)
46	Series 05-1	990	-	-	-	-	(42)	949
47	Tax Impact	(361)	-	-	-	-	15	(346)
48	Series 07-1	1,121	-	-	-	-	(32)	1,090
49	Tax Impact	(400)	-	-	-	-	11	(389)
50	MTN-2009	924	-	-	-	-	(34)	890
51	Tax Impact	(173)	(59)	-	-	-	6	(226)
52	MTN-2010	846	-	-	-	-	(23)	823
53	Tax Impact	(89)	(37)	-	-	-	2	(123)
54		**3,765**	**(96)**	**-**	**-**	**-**	**(364)**	**3,305**
55								
56	**Total Rate Base Deferred Projects**	**11,127**	**5,339**	**-**	**6,156**	**-**	**(3,570)**	**19,052**

Note: Minor differences due to rounding.

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2012

Line		Balance at Jan 1, 2012	Additions and Transfers	Add Deferred Interest	Amortized / Transferred to Other Accounts ($000s)	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2012
	Non Rate Base Deferral Accounts Attracting WAC-D Interest Rates:							
57	**Preliminary and Investigative Charges**							
58	Pumped Storage Hydro	-	-	-	-	-	-	-
59	2012 Integrated System Plan	2,559	(2,559)	-	-	-	-	-
60	P1 - P4 Sustainment Capital	6	-	(0)	(6)	-	-	(0)
61	Kelowna Bulk Transformer Capacity Addition	198	108	15	-	-	-	322
62	P4 Spillway Concrete & Spill Gate Rehab CPCN	-	75	2				78
63		**2,764**	**(2,376)**	**17**	**(6)**	**-**	**-**	**399**
64	**Deferred Regulatory Expense**							
65	2012 Integrated System Plan	-	2,601	58	-	(16)	(677)	1,965
66	Tax Impact	-	(650)	(14)	-	4	169	(491)
67	2014-15 CEP	-	259	8		-	-	267
68	Tax Impact	-	(65)	(2)		-	-	(67)
69	Renewal of BCH Power Purchase Agreement	138	145	8	-	(7)	(155)	129
70	Tax Impact	(41)	(36)	(2)	-	2	43	(34)
71	2012 Integrated System Plan and 2012-2013 Revenue Requirements	1,519	886	69	-	(74)	(1,645)	755
72	Tax Impact	(439)	(222)	(19)	-	21	454	(206)
73		**1,177**	**2,918**	**104**	**-**	**(71)**	**(1,810)**	**2,319**
74	**Other Deferred Charges and Credits**							
75	Prepaid Pension Costs	6,979	(4,130)	296	-	(514)	-	2,631
76	Tax Impact	(633)	1,033	(8)	-	64	(46)	409
77	Other Post Employment Benefit (OPEB)	(13,374)	(7,880)	(1,042)	-	1,021	-	(21,276)
78	Tax Impact	4,020	1,970	297	-	(291)	(161)	5,835
79	US GAAP Pension transitional Obligation	-	2,194	61	(183)	(5)	-	2,066
80	Tax Impact	-	(549)	(15)	-	1	46	(516)
81	US GAAP OPEB Transitional Obligation	-	5,488	146	(644)	(16)	-	4,974
82	Tax Impact	-	(1,372)	(36)	-	4	161	(1,243)
83	Right of Way Encroachment Litigation	91	-	5	-	-	-	97
84	Tax Impact	(28)	-	(2)	-	-	-	(29)
85	Mandatory Reliability Standards	1,051	-	53	-	(17)	(333)	754
86	Tax Impact	(296)	-	(15)	-	5	94	(212)
87	2012 MRS O&M Expense	-	320	10	-	-	-	330
88	Tax Impact	-	(80)	(3)	-	-	-	(83)
89	Business Development (CoK)	-	140	4	-	-	-	145
90	Tax Impact	-	(35)	(1)	-	-	-	(36)
91	2012 Generic Cost of Capital Proceeding - BCUC	-	16	0	-	-	-	17
92	Tax Impact	-	(4)	(0)	-	-	-	(4)
93	Transmission Customer Rate Design	-	80	2	-	-	-	82
94	Tax Impact	-	(20)	(1)	-	-	-	(21)
95	2012 MRS Audit	-	571	17	-	-	-	588
96	Tax Impact	-	(143)	(4)	-	-	-	(147)
97		**(2,190)**	**(2,400)**	**(236)**	**(827)**	**252**	**(239)**	**(5,640)**
98	**Other Projects:**							
99	Advanced Metering Infrastructure Project	2,118	447	85	-	-	-	2,650
100		**2,118**	**447**	**85**	**-**	**-**	**-**	**2,650**
	Non Rate Base Deferral Accounts Attracting ST Interest Rates:							
101	**Deferred Regulatory Expense**							
102	Shaw Application for Transmission Facility Access	367	(367)	-	-	-	-	0
103	Tax Impact	(103)	103	-	-	-	-	(0)
104	2012 Over Collection	-	(1,941)	(28)	-	-	-	(1,969)
105	Power Purchase Expense Variance	-	(8,362)	(121)	-	-	-	(8,483)
106	Tax Impact	-	-	-	-	-	-	-
107	Revenue Variance	-	3,377	49	-	-	-	3,426
108	Tax Impact	-	-	-	-	-	-	-
109	Water Fees Variance	-	(75)	(1)	-	-	-	(76)
110	Tax Impact	-	-	-	-	-	-	-
111	HST Removal or Reform Variance	-	3	-	-	-	-	3
112	Tax Impact	-	(1)	-	-	-	-	(1)
113	Property Tax Asset Valuation Review	-	-	-	-	-	-	-
114	Tax Impact	-	-	-	-	-	-	-
115	Pension and Other Post Employment Benefits Expense Variance	-	4,155	60	-	-	-	4,215
116	Tax Impact	-	(1,039)	(15)	-	-	-	(1,054)
117	Extraordinary Costs Variance	-	-	-	-	-	-	-
118	Tax Impact	-	-	-	-	-	-	-
119	Irrigation Rate Payer Group Consultation and Load Research	18	41	1	-	-	-	60
120	Tax Impact	(5)	(10)	(0)	-	-	-	(15)
121	Kettle Valley Expenditure Review	-	70	-	-	-	-	70
122	Tax Impact	-	(17)	-	-	-	-	(17)
123	BCUC Mandatory Reliability Compliance Inquiry	-	1	0	-	-	-	1
124	Tax Impact	-	(0)	0	-	-	-	(0)
125		**277**	**(4,063)**	**(55)**	**-**	**-**	**-**	**(3,841)**
	Non Rate Base Deferral Accounts Attracting AFUDC:							
126	Kettle Valley	-	1,879	-	-	-	-	1,879
127								
128	**Total Non-Rate Base Deferred Projects**	**4,147**	**(3,595)**	**(85)**	**(833)**	**181**	**(2,049)**	**(2,234)**
129								
130	**Grand Total of All Deferred Charges**	**15,274**	**1,744**	**(85)**	**5,323**	**181**	**(5,619)**	**16,817**

***Note 1** In compliance with BCUC Order G-73-12, all revenue requirement effects of the Kettle Valley Project have been placed in a Non-Rate Base Deferral Account attracting AFUDC.*
This includes depreciation of $835, tax impact of ($421), and AFUDC of $1,465.
The Net Book Value of the Kettle Valley Project of $25,756 is included in Plant in Service and removed from rate base by an adjustment on Line 26 on Schedule 1.

***Note:** The opening 2012 deferred charge balance included in rate base has been adjusted by $1,015 to reflect compliance with Order G-110-12.*
Rate Base adjustment to Mean Depreciated Rate Base (Line 24 Schedule-1) is 50% of December 31, 2011 Rate Base accounts (Schedule-1, Line 8), less
Jan 1, 2012 Rate Base accounts (Line 130 above), or ($13,157 - $11,127)/2 = $1,015

Note: Minor differences due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2012

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2011	Approved Deprec. Rate	Asset Balance Dec. 31, 2011	Depreciation Expense Dec. 31, 2012	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2012
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(545)	3.8%	962	37	-	(509)
2	331	Structures and Improvements	5,456	1.3%	12,793	165	(88)	5,533
3	332	Reservoirs, Dams and Waterways	5,940	2.0%	27,349	550	(158)	6,331
4	333	Water Wheels, Turbines & Generators	2,765	2.0%	94,113	1,835	(51)	4,550
5	334	Accessory Electrical Equipment	7,574	2.4%	38,990	920	(622)	7,872
6	335	Other Power Plant Equipment	10,177	2.3%	41,897	972	(442)	10,706
7	336	Roads, Railroads, and Bridges	504	1.5%	1,287	19	-	523
8			31,870	2.1%	217,390	4,498	(1,361)	35,007
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	7,311	-	-	(62)
11	350.1	Land Rights - Clearing	2,166	1.5%	6,276	92	-	2,258
12	353	Station Equipment	1,839	3.4%	181,474	6,240	(278)	7,800
13	355	Poles Towers & Fixtures	9,969	2.6%	91,799	2,419	(371)	12,018
14	356	Conductors and Devices	6,253	2.1%	89,621	1,834	(1,356)	6,731
15	359	Roads and Trails	121	2.7%	1,121	30	-	152
16			20,287	2.8%	377,603	10,616	(2,005)	28,897
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	2,889	-	-	(868)
19	360.1	Land Rights - Clearing	181	2.7%	10,017	264	-	446
20	362	Station Equipment	75,557	2.2%	223,800	4,645	(265)	79,936
21	364	Poles Towers & Fixtures	44,109	2.1%	145,239	3,030	(889)	46,249
22	365	Conductors and Devices	68,091	2.6%	236,922	5,992	(1,065)	73,018
23	368	Line Transformers	21,858	3.4%	110,795	3,737	(1,443)	24,152
24	369	Services	6,547	0.2%	7,292	11	-	6,559
25	370	Meters	5,561	6.7%	14,102	945	(362)	6,144
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,638	2.4%	12,208	285	(57)	3,865
28			221,261	2.5%	764,202	18,909	(4,082)	236,088
29		General Plant						
30	389	Land	897	0.0%	12,157	-	-	897
31	390	Structures - Frame & Iron	539	0.7%	337	2	-	541
32	390.1	Structures - Masonry	4,861	6.1%	23,593	1,415	-	6,276
33	391	Office Furniture & Equipment	4,671	3.6%	5,902	215	-	4,886
34	391.1	Computer Equipment	48,001	7.6%	69,134	5,261	(128)	53,134
35	392	Transportation Equipment	1,293	10.7%	21,000	2,250	(700)	2,843
36	394	Tools and Work Equipment	8,280	4.0%	11,784	475	(86)	8,669
37	397	Communication Structures and Equipment	8,666	8.1%	23,932	1,609	-	10,275
38			77,210	6.7%	167,839	11,227	(914)	87,523
39								
40	108	Total Accumulated Depreciation	350,628	3.0%	1,527,034	45,249	(8,362)	387,515
41								
42		Deduct - Portion of CIAC Depreciated				(3,344)		
43								
44	403	Depreciation Expense				41,906		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,210		11,912	186		5,396
48	390.1	Leasehold Improvements	3,097		4,796	746		3,843
49		Rate Stabilization Adjustment	(1,243)			311		(932)
50		Total Accumulated Amortization	7,064			1,243		8,307
51								
52		Accumulated Amortization per						
53		Balance Sheet	357,692			43,149		395,823

Note: Minor differences due to rounding.

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2012

Lag Days Calculation	Lag (Lead) Days	2012 Actual ($000s)	2012 Extended ($000s)	Weighted Average Lag Days
Revenue				
Tariff Revenue	43.3	282,943	12,251	
Other Revenue:				
Apparatus and Facilities Rental	27.6	5,018	138	
Contract Revenue	41.4	1,943	80	
Miscellaneous Revenue	43.5	2,182	95	
Investment Income	15.2	126	2	
		$ 292,212	**$ 12,567**	**43.0**
Expenses				
Power Purchases	42.0	75,999	3,192	
Wheeling	40.2	4,813	194	
Water Fees	(1.0)	9,253	(9)	
Operating Labour:				
Salaries & Wages	6.8	12,993	88	
Employee Benefits	36.1	9,874	356	
Contracted Manpower	50.6	9,889	500	
Property Tax	1.4	13,912	19	
Rental of T&D Facilities	48.6	3,206	156	
Office Lease - Kelowna	(15.2)	803	(12)	
Office Lease - Trail	91.5	1,212	111	
Materials	39.4	4,050	160	
Insurance	(182.5)	547	(100)	
Income Tax	15.2	9,097	138	
Interest	88.3	38,686	3,416	
		$ 194,333	**$ 8,209**	**42.2**
Net Lag/(Lead) Days				**0.8**

Working Capital Allowance	($000s)	
Lead-Lag Study Allowance:		
Net Lag Days/365 times Expenses		407
Add Funds Unavailable:		
Average Customer Loans (related to energy management)	2,131	
Average Employee Loans	270	
Average of Uncollectable Accounts	1,011	
Average Inventory (forecast monthly average investment)	437	
		3,849
Less Funds Available:		
Average Customer Deposits	3,874	
Average Harmonized Sales Tax	1,646	
		5,520
2012 ALLOWANCE FOR WORKING CAPITAL		**(1,264)**

Note: Minor differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS
FOR THE YEAR ENDING DECEMBER 31, 2012

		Additions to Plant in Service * ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	2,184	11.5	2,093
2	February	3,208	10.5	2,807
3	March	2,913	9.5	2,306
4	April	3,976	8.5	2,816
5	May	3,396	7.5	2,122
6	June	3,424	6.5	1,854
7	July	4,358	5.5	1,998
8	August	2,426	4.5	910
9	September	6,879	3.5	2,006
10	October	8,803	2.5	1,834
11	November	4,894	1.5	612
12	December	10,800	0.5	450
13	**Total**	**57,261**		**21,808**
14	Less Simple Average			28,631
15	Adjustment to Capital Additions			**(6,822)**

16 * *Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:*

17	Gross Plant in Service Additions	62,725
18	CIAC	(5,464)
19	Net Capital Additions	**57,261**

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2011	Decision 2012	Actual 2012	Normalized 2012	Change from Decision
1	SALES VOLUME (GWh)	3,129	3,193	3,144	3,149	(44)
2						
3				($000s)		
4	ELECTRICITY SALES REVENUE	275,898	287,445	282,943	283,394	(4,051)
5						
6	EXPENSES					
7	Power Purchases	70,458	87,149	75,999	74,464	(12,685)
8	Water Fees	9,047	9,353	9,253	9,253	(100)
9	Wheeling	4,281	4,725	4,813	4,813	88
10	Net O&M Expense	42,299	43,874	42,574	42,574	(1,301)
11	Property Tax	13,408	14,532	13,912	13,912	(620)
12	Depreciation and Amortization	45,349	49,178	48,587	48,587	(591)
13	Other Income	(7,506)	(7,481)	(9,270)	(9,270)	(1,789)
14	Incentive Adjustments	4,116	(4,280)	781	781	5,060
15	UTILITY INCOME BEFORE TAX	94,446	90,394	96,293	98,280	7,886
16	Less:					
17	INCOME TAXES	9,382	6,165	9,097	9,593	3,428
18						
19	EARNED RETURN	85,064	84,229	87,197	88,686	4,458
20	RETURN ON RATE BASE					
21	Utility Rate Base	1,065,892	1,112,302	1,088,470	1,088,470	(23,832)
22	Return on Rate Base	7.98%	7.57%	8.01%	8.15%	0.58%

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2012

Line	Account		2012	2011	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	561	666	(106)
3	536	Water Fees	9,253	9,047	206
4	542	Structures	642	697	(55)
5	543	Dams & Waterways	308	270	38
6	544	Electric Plant	574	534	40
7	545	Other Plant	224	271	(47)
8			11,561	11,485	76
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	75,999	71,519	4,480
12	556	System Control	1,867	1,805	62
13			77,866	73,324	4,542
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,678	1,634	45
17	560R-2	System Planning	2,136	2,148	(13)
18	561	Load Dispatching	1,179	1,193	(14)
19	562	Transmission Station Expense	1,230	902	328
20	563R-1	Transmission Line Maintenance	738	570	168
21	563R-2	Transmission ROW Maintenance	1,506	1,218	288
22	565	Wheeling	4,813	4,281	533
23	567	Rents	3,206	3,033	173
24	583R-1	Distribution Line Maintenance	3,377	3,304	72
25	583R-2	Distribution ROW Maintenance	3,809	3,684	125
26	586	Meter Expenses	918	1,030	(112)
27	592	Distribution Station Expense	1,150	1,313	(164)
28	596	Street Lighting	74	78	(4)
29	598	Other Plant	255	249	6
30			26,069	24,639	1,430
31					
32		CUSTOMER SERVICE			
33	901	Supervision & Administration	1,461	1,128	333
34	902	Meter Reading	2,010	2,030	(20)
35	903	Customer Billing	596	646	(50)
36	904	Credit & Collections	782	683	98
37	910	Customer Assistance	2,306	2,462	(156)
38			7,154	6,949	206

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2012

Line	Account		2012	2011	Change
				($000s)	
39					
40		ADMINISTRATIVE AND GENERAL			
41	920	Salaries			
42	920.1	Executive & Senior Management	986	1,371	(385)
43	920.2	Legal	668	687	(19)
44	920.3	Human Resources	800	788	12
45	920.4	Finance & Accounting	908	1,065	(157)
46	920.6	Information Services	836	903	(68)
47	920.7	Materials Management	143	184	(41)
48		Other	290	288	2
49			4,631	5,287	(656)
50					
51	921	Expenses			
52	921.1	Executive & Senior Management	93	142	(49)
53	921.2	Legal	461	87	374
54	921.3	Human Resources	112	182	(70)
55	921.4	Finance & Accounting	13	80	(67)
56	921.6	Information Services	658	638	20
57	921.7	Materials Management	47	(3)	50
58		Other	215	390	(175)
59			1,599	1,516	83
60					
61	923	Special Services	1,078	966	111
62	924	Insurance	547	550	(3)
63	932	Maintenance to General Plant	1,567	1,719	(151)
64	933	Transportation Equipment Expenses	567	712	(145)
65			3,759	3,947	(188)
66					
67		TOTAL	132,639	127,146	5,493
68					
69					
70					
71	Less:	Wheeling	(4,813)	(4,281)	(533)
72		Power Purchases	(75,999)	(71,519)	(4,480)
73		Water Fees	(9,253)	(9,047)	(206)
74	O & M Expense per Financial Statements		42,574	42,299	274
75					
76	Add:	Capitalized Overhead	10,969	10,777	192
77					
78	**Gross O&M**		**53,542**	**53,076**	**466**

Note: Minor differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2012

		($000s)	
1	Amortization of Prior Year Incentives		
2	Amortization of 2010 Incentives	(380)	
3	Amortization of 2011 Incentives	(5,840)	
4			
5	Total Amortization of Prior Year Incentives		(6,220)
6			
7	Current Year Flow Through Adjustments		
8	Revenue	(3,377)	
9	Power Purchase	8,362	
10	Water Fees	75	
11	Overcollection 2012 (Post Tax)	1,941	
12			
13	Total 2012 Flow Through Adjustments	7,001	
14			
15	Total Regulatory Incentive Adjustments		7,001
16			
17	Incentive Adjustments per Income Statement		781

Note: Minor differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2012

2012 Flow Through Adjustments	Approved	Actual	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
				($000s)			
1 Revenue	(287,445)	(282,943)	(4,503)	(1,126)	(3,377)	100%	(3,377)
2 Power Purchase	87,149	75,999	11,150	2,787	8,362	100%	8,362
3 Water Fees	9,353	9,253	100	25	75	100%	75
4 Overcollection 2012 (Post Tax)	-	(1,941)	1,941	-	1,941	100%	1,941
5 Flow Through Adjustment							7,001

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2012

		Normalized 2011	Decision 2012	Actual 2012	Normalized 2012	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	94,446	90,394	96,293	98,280	7,886
2	Deduct:					
	Interest on Non Rate Base Deferral Account	-			-	-
3	Interest Expense	38,893	40,182	38,686	38,686	(1,496)
4	ACCOUNTING INCOME	55,553	50,212	57,607	59,594	9,382
5						
6	Deductions:					
7	Capital Cost Allowance	57,441	59,395	58,308	58,308	(1,087)
8	Capitalized Overhead	10,777	10,969	10,969	10,969	-
9	Incentive & Revenue Deferrals	(4,116)	4,280	(781)	(781)	(5,060)
10	Financing Fees	587	345	338	338	(7)
11	All Other (net effect)	879	134	463	463	329
12		65,568	75,122	69,297	69,297	(5,825)
13						
14	Additions:					
15	Amortization of Deferred Charges	3,236	5,439	5,439	5,439	(0)
16	Depreciation	42,113	43,740	43,149	43,149	(591)
17		45,349	49,178	48,587	48,587	(591)
18						
19	TAXABLE INCOME	35,334	24,269	36,898	38,885	14,616
20						
21	Tax Rate	26.50%	25.00%	25.00%	25.00%	0.00%
22						
23	Taxes	9,363	6,067	9,224	9,721	3,654
24	Investment Tax Credit	(39)	-	(18)	(18)	(18)
25	Tax Payable	9,325	6,067	9,206	9,703	3,636
26	Prior Years' Overprovisions/(Underprovisions)	(127)	-	(167)	(167)	(167)
27	Deferred Charges Tax Effect	184	98	57	57	(41)
28						
29	REGULATORY TAX PROVISION	9,382	6,165	9,097	9,593	3,428

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2012

			Normalized 2011	Decision 2012	Actual 2012	Normalized 2012	Change From Decision
					($000s)		
1	Share Capital		180,122	180,122	180,122	180,122	-
2	Retained Earnings		238,424	268,275	268,691	268,691	416
3							
4	COMMON EQUITY - OPENING BALANCE		418,546	448,397	448,813	448,813	416
5							
6	Less:	Common Dividends	(16,000)	(24,000)	(24,000)	(24,000)	-
7	Add:	Net Income	46,171	44,047	48,510	50,001	5,954
8		Share Adjustment	-	-	-	-	-
9		Shares Issued	-	-	-	-	-
10							
11	COMMON EQUITY - CLOSING BALANCE		448,717	468,445	473,323	474,814	6,370
12							
13	SIMPLE AVERAGE		433,631	458,421	461,068	461,814	3,393
14							
15	Adjustment for Shares Issued		-	-	-	-	-
16	Deemed Equity Adjustment		-	(13,500)	-	-	13,500
17							
18	COMMON EQUITY - AVERAGE		433,631	444,921	461,068	461,814	16,893

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2012

		Normalized 2011	Decision 2012	Actual 2012	Normalized 2012	Change From Decision
				($000s)		
1	Secured and Senior Unsecured Debt	640,000	637,483	637,483	637,483	-
2	Proportion	60.04%	57.31%	57.22%	57.22%	-0.10%
3	Embedded Cost	6.04%	6.03%	6.03%	6.03%	0.00%
4	Cost Component	3.63%	3.45%	3.45%	3.45%	-0.01%
5	Return	38,664	38,422	38,422	38,422	-
6						
7	Short Term Debt	(7,787)	29,898	15,599	15,599	(14,299)
8	Proportion	-0.73%	2.69%	1.40%	1.40%	-1.29%
9	Embedded Cost	-2.93%	5.89%	1.69%	1.69%	-4.19%
10	Cost Component	0.02%	0.16%	0.02%	0.02%	-0.13%
11	Return (including fees)	228	1,760	264	264	(1,496)
12						
13						
14	Common Equity	433,631	444,921	461,068	461,814	16,893
15	Proportion	40.68%	40.00%	41.38%	41.42%	1.42%
16	Embedded Cost	10.65%	9.90%	10.52%	10.83%	0.93%
17	Cost Component	4.33%	3.96%	4.35%	4.48%	0.52%
18	Return	46,171	44,047	48,510	50,001	5,954
19						
20	TOTAL CAPITALIZATION	1,065,844	1,112,302	1,114,150	1,114,896	2,594
21	RATE BASE	1,065,892	1,112,302	1,088,470	1,088,470	(23,832)
22						
23	Earned Return	85,064	84,229	87,195	88,686	4,458
24						
25	RETURN ON CAPITAL	7.98%	7.57%	7.83%	7.95%	0.38%
26	RETURN ON RATE BASE	7.98%	7.57%	8.01%	8.15%	0.58%

Note: Minor differences due to rounding.