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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-184-10

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
2010 Annual Review, 2011 Revenue Requirements and
Negotiated Settlement Process

BEFORE: L.F. Kelsey, Commissioner
D.A. Cote, Commissioner
N.E. MacMurchy, Commissioner
D. Morton, Commissioner

December 9, 2010

O R D E R

WHEREAS:

A. British Columbia Utilities Commission (Commission) Order G-58-06 approved for FortisBC Inc. (FortisBC or Company) a Settlement Agreement for its 2006 Revenue Requirements (the 2006 Settlement Agreement) and a Performance Based Regulation Settlement for the years 2007, 2008 and potentially 2009 (the PBR Settlement). The PBR Settlement requires FortisBC to hold an Annual Review, Workshop and Negotiated Settlement Process (NSP) each November with a goal of achieving firm rates by December 1 for the following year;

B. The Annual Review compares the Company's actual performance for the recently completed year to the approved targets for the Performance Standards to determine whether the Company is entitled to an incentive payment. The Revenue Requirements Workshop is to focus on future test periods and the NSP is conducted to establish rates for the following year;

D. Commission Order G-193-08, issued on December 11, 2008, approved an extension of the 2007-2009 Performance-Based Rate Plan for the years 2009-2011;

F. On October 1, 2010, FortisBC filed its Preliminary 2011 Revenue Requirements, which sought a 5.9 percent general rate increase to be effective January 1, 2011;

E. By Order G-142-10 dated September 16, 2010, the Commission established a Regulatory Timetable for the 2010 Annual Review and a 2011 Revenue Requirements Workshop on November 16, 2010 in Kelowna, BC, followed by an NSP on November 17, 2010;

G. By October 15, 2010, the Commission and Interveners issued Information Requests to FortisBC, which were responded to on October 29, 2010;

H. On November 1, 2010, FortisBC filed the 2011 Revenue Requirements Update, which incorporated financial results and forecasts up to September 30, 2010, and increased the general rate increase sought to 6.2 percent, effective January 1, 2011;

I. As a result of the 2010 Annual Review on November 17, 2010 and 2011 Revenue Requirements Settlement discussions on November 17, 2010, a Settlement Agreement was proposed and agreed to by FortisBC and the majority of Interveners in attendance, with the participation of Commission Staff. The proposed Settlement Agreement, which results in a general rate increase of 5.2 percent effective January 1, 2011, was circulated to all participants/registered Interveners on December 2, 2010;

J. The proposed Settlement Agreement's financial schedules are based on FortisBC's 2011 Capital Expenditure Plan application which is currently before the Commission and reviewed under a separate process. If a decision is issued prior to determining final 2011 rates for FortisBC, the resulting FortisBC revenue requirements will be used to determine final rates. Otherwise, FortisBC would implement any resulting change to 2011 Revenue Requirements and rates by way of a flow-through adjustment at the time of that decision;

K. Letters of support for the proposed Settlement Agreement were received from the British Columbia Old Age Pensioners' Organization *et al.*, Mr. Allan Wait, the British Columbia Municipal Electric Utilities, Zellstoff Celgar, Mr. Norm Gabana and FortisBC;

L. The Commission has reviewed the proposed Settlement Agreement and considers that approval is warranted.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the Negotiated Settlement Agreement attached as Appendix A to this Order, and the Terms of Settlement along with financial schedules showing the effect of changes arising from the Negotiated Settlement.

2. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules in accordance with the terms of this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of December 2010.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

~~CONFIDENTIAL~~

FortisBC Inc. 2011 Revenue Requirements Negotiated Settlement Agreement

Introduction

FortisBC Inc. ("FortisBC" or the "Company") filed its Preliminary 2011 Revenue Requirements (the "Application") on October 1, 2010. The Application materials were filed on the basis of the Performance Based Regulation ("PBR") extension negotiated in 2009 between FortisBC and its Stakeholders for the years 2009-2011.

The Application reflected a general rate increase of 5.9 percent effective January 1, 2011. Following the submission of Information Requests by the Commission and Registered Intervenors and filing of responses, the Company filed an update to the 2011 Revenue Requirements Application on November 1, 2010 (the "Update"), incorporating financial results and forecasts as of September 30, 2010, final Performance Standards for the period October 1, 2009 to September 30, 2010, and other current information. The requested rate increase was increased, as a net result of the adjustments, to 6.2 percent, effective January 1, 2011 subject to the outcome of a Negotiated Settlement Process ("NSP").

The Application also requested Commission approval of certain non-rate base deferral accounts required for International Financial Reporting Standards ("IFRS") implementation. As these deferral accounts are excluded from rate base, they do not impact customer rates for 2011.

The 2010 Annual Review and 2011 Revenue Requirements Workshop were held in Kelowna, BC on November 16, 2010. FortisBC and a group of Intervenors participated in a NSP on November 17, 2010, and reached a Settlement Agreement, which is attached. On November 19, 2010, the Commission issued a proposed settlement package in the BC Hydro fiscal 2011 Revenue Requirements Application. The Company has incorporated the proposed final BC Hydro rate increase into its own Revenue Requirements calculations included in the financial schedules included with the Settlement Agreement. Should the final BCH NSA differ from the draft, FortisBC will flow the impact of the change in power purchase expense and water fees through 2011 rates as soon as practicable after BC Hydro rates are considered firm.

The net result of the NSA items and the BC Hydro increase is a general rate increase of 5.2 percent effective January 1, 2011. The 2011 Revenue Requirements Schedules reflect the increase on total load by 3 MWh and resulting increase in 2011 Power Purchase Expense, a $450,000.00 increase in revenue from Zellstoff-Celgar, a $750,000.00 reduction in power purchase expense, the final actuary determined Pension and Post Retirement benefit expense, and other adjustments pursuant to the NSA.

The following Parties participated in the NSP:

Participant	**Party**
W.J. Grant	British Columbia Utilities Commission consultant
P. Nakoneshny	British Columbia Utilities Commission
Y. Domingo	British Columbia Utilities Commission
J. Tran	British Columbia Utilities Commission
D. Flintoff	British Columbia Utilities Commission
E. Switlishoff	Consultant for Zellstoff-Celgar Limited Partnership
A. Love	The British Columbia Municipal Electricity Utilities, Nelson Hydro
H. Grant	The British Columbia Municipal Electricity Utilities, Nelson Hydro
Cecile Arnott	The British Columbia Municipal Electricity Utilities, The City of Grand Forks
C. McNeely	The British Columbia Municipal Electricity Utilities, The City of Kelowna
K. Ostraat	The British Columbia Municipal Electricity Utilities, The District of Summerland
M. Moroziuk	The British Columbia Municipal Electricity Utilities, The City of Penticton
E. Livolsi	The British Columbia Municipal Electricity Utilities, The City of Penticton
C.P. Weafer	Counsel for The BC Municipal Electric Utilities
S. Khan	British Columbia Old Age Pensioners Organization et al.
D. Bursey	Counsel for Shaw Cable Systems
A. Wait	FortisBC Ratepayer
N. Gabana	FortisBC Ratepayer
M. Leeners	FortisBC Inc.
C. Sinclair	FortisBC Inc.
D. Swanson	FortisBC Inc.
S. Thomson	FortisBC Inc.

Settlement Agreement

The Parties accept the 2011 Revenue Requirements Application, including the recognition of IFRS-related non-rate base deferral accounts, as filed, subject to the following:

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December 2, 2010

ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 3 – Revenue Requirements				
1	AMI development cost – FBC's proposal to move the deferred AMI costs to Rate base in 2011 is premature.	Order G-168-08 denied FortisBC's AMI Project CPCN. In that Decision, the Commission Panel provides guidance to FortisBC for its next CPCN, which includes the exploration of coordinating meter technology selection with that of BC Hydro.	FortisBC believes that the costs are prudently incurred and are consistent with Commission Order G-168-08. All such costs should be included in rate base. However FortisBC agrees, for the purpose of this NSA, to record the AMI development costs in a non-rate base deferral account that will attract AFUDC for the 2011 Revenue Requirement, on a without prejudice basis.	FBC 2011 Capital Expenditure Plan (p.3) Exhibit B-1, Tab 3, p.40 Exhibit B-3, BCUC IR 16.1
2	FBC's proposal of a 5-year amortization on the COSA and RDA deferral accounts seems too long.	The COSA and RDA deferral account should be amortized over 4 years. FBC says it will file new COSA and RDA in 3-5 years. It would be Ideal to have deferral account fully amortized prior to implementation of next application.	Amortization of the COSA and RDA deferral accounts will be over 4 years	Exhibit B-1, Tab 3, p.31 Exhibit B-3, BCUC IR 14.1.1
3	DSM Study deferral account proposed to be amortized over 5 years.	The DSM study deferral account should be amortized over 3 years to reduce carrying cost.	Amortization of the COSA DSM deferral account will be over 3 years.	Exhibit B-1, Tab 3, pp.37-38 Exhibit B-3, BCUC IR 15.3.1
4	Section 71 Filing deferral account proposed to be amortized over 5 years.	Section 71 Filing deferral account should be amortized over 3 years to reduce carrying cost.	Amortization of the Section 71 Filing deferral account will be 3 over years.	Exhibit B-1, Tab 3, p.38 Exhibit B-3, BCUC IR 15.4
5	FBC has separate Regulatory Deferral accounts for the Resource Plan Update and the Integrated System Plan.	FBC should combine these 2 Deferred Regulatory accounts as the filings will be combined in 2011.	FBC will combine these two deferral accounts into a single Integrated System Plan ("ISP") deferral account.	Exhibit B-1, Tab 3, p.34

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ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 5 – Load and Customer Forecast				
1	2011 forecast Residential volume understated.	The parties do not agree with the forecast number of customers of 99,663 as presented in the Workshop. Some participants in the NSA believe that the forecast number of customers should be 99,743 based on the forecast population for the Fortis BC region for 2010 and 2011 as per Exhibit B-3, p. 227. Increase forecast Residential energy volume for 2011 by 2 GWh to 1,261 GWh without increasing either the customer count or the calculated O&M Expense in the revenue requirement.	Residential Energy volume for 2011 will be increased by 2 GWh to 1,261 GWh. FBC is to also adjust power purchase costs and Revenue Requirements accordingly. This increase is independent of the increase in power purchase costs related to the $750k reduction noted in Tab 6, Item 2 below. The total residential increase to revenue at prior year rates of $166K is partially offset by an increase of $78K to 2011 Power Purchase Expense.	1) Exhibit B-3, p. 227 2) Exhibit B-1-4, p.12
2	2011 forecast Irrigation volume understated	Increase forecast Irrigation energy volume for 2011 by 1 GWh to 45 GWh to reflect the last 5-year average. FBC has not provided a proper justification for using the 2004-2008 average.	Irrigation Energy volume for 2011 will be increased by 1 GWh to 45 GWh. FBC is to also adjust power purchase costs and Revenue Requirements accordingly. This increase is independent of the increase in power purchase costs related to the $750k reduction noted in Tab 6, Item 2 below. The total irrigation increase to revenue at prior year rates of $61K is partially offset by an increase of $39K to 2011 Power Purchase Expense.	Exhibit B-3, BCUC 43.1, pp.98-99
3	Forecasting methods require more transparency.	In the next RRA and subsequent ones, FBC should submit an application that shows more transparently how they calculate the load forecast for each class of customers. In particular, FBC should provide, as part of its initial application, a clear explanation of forecasting methods with all supporting formulas and regressions, and referenced	In the 2012 RRA, FortisBC will provide more transparency in its load forecast methodology. It will also re-instate a load forecast technical committee offering participation to Commission staff and Intervenors.	1) Exhibit B-1, Tab 5 2) Exhibit B-1, Tab 5, pp. 4-5 3) Exhibit B-1-4, pp. 11-13

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ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
		source materials and historical data (*e.g.,* 10- or 20-year historical data, both in graphs and tabular form). This would significantly reduce the number of IRs from staff. Subsequently, when FBC provides forecast updates, it should also clearly show how these revised forecasts were calculated. The calculation methods used to forecast the energy load for the Residential, General Service, Industrial and Irrigation classes of customers were not clearly and sufficiently explained to determine the reasonableness of the forecast. None of the formulas or regressions used to forecast load were provided in the initial application. In its initial application, FBC did not provide the referenced source materials used to forecast loads (e.g., the Conference Board of Canada Provincial Outlook and B.C. Stats P.E.O.P.L.E report for FortisBC population forecasts). Since these sources are not available to staff on the Internet, it is difficult to assess the reasonableness of FBC's load forecasts. In its initial application, FBC referred heavily to historical data in its load forecasts but provides almost no supporting historical data that would help stakeholders assess the reasonableness of the forecasts.		

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ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
4	FBC should leverage its knowledge gained from DSM planning into its load forecast.	FBC should increase its efforts to understand its customers and what influences the energy demand through the use of end-use surveys or more detailed analysis of the UPC, including the energy use of newly added customers and the potential impact of a changing housing stock on energy demand for example. FBC uses the results of linear regressions that have no explanatory power to forecast UPC, using only TIME as the regressor.	In the 2012 RRA, FBC will demonstrate further how they have a good grasp of their customers, especially the Residential and General Service classes of customers and how their respective UPC may be influenced by variables such as the changing housing mix, home characteristics, etc.	Exhibit B-1, Tab 5
Tab 6 – Power Purchase and Wheeling				
1	2011 Power Purchase expenses	In order to mitigate the rate impact of BC Hydro's rate increases, FBC should flow through any BC Hydro rate increases as soon as reasonably possible.	FortisBC has included in the financial schedules accompanying this NSA 2010 and 2011 power purchase expense that reflects the results of the BCH Hydro draft NSA. Should the final BCH NSA differ from the draft, FortisBC will flow the impact of the change in power purchase expense and water fees through 2011 rates as soon as practicable after BC Hydro rates are considered firm. FBC will apply for interim flow through of BC Hydro's F2012 power purchase expenses as soon as reasonably possible.	Exhibit B-1, Tab 2, p.4; Tab 6, p.9
2	2011 Power Purchase Expense	FBC annually finds opportunities to reduce Power Purchase expense by taking advantage of market purchases during spring freshet and other opportunities.	Reduce 2011 Power Purchase expense by $750K.	Exhibit B-1, Tab 6, p.3 and p.5

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	ISSUE DESCRIPTION	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
3	Future Power Purchase Expense forecasts.	BCH has Non Heritage Deferral Accounts and Heritage Deferral Accounts for true-up of Power Purchases.	In the next RRA, FBC is to provide a discussion on their Power Purchase forecasting techniques, including the costs and benefits of the potential use of a deferral account to true up Power Purchases.	
Tab 8 – Performance Standards				
	Safety & Reliability	Pursuant to G-147-07, FBC was directed to file a Safety Program including its efforts to manage the injury severity rate. Results for that metric have improved since this report but they have done less well on others. 2012 Performance targets are attached at the end of this document.	In the 2012 RRA, FBC should file an update to its Safety Program, along with information on various initiatives, monitoring activities and benchmarks on how to measure its success.	Exhibit B-1, Tab 8, p. 3 Exhibit B-3, BCUC IR 57.2 and 58.0
Tab – Appendix A – Prior Years Directives				
	The Company will summarize and discuss the worst 20 performing feeders at the 2010 Annual Review.	FBC agreed to "present a plan" involving the worst performing circuits to lower SAIDI to improve CAIDI in the 2008 Annual Review / 2009 NSP (G-193-08).	FBC is to develop a "plan" for addressing these worst performing feeders as part of its 2012 RRA. This plan could be a detailed justification of why the Company does not propose using this methodology for determining capital and maintenance activities.	Exhibit B-3, BCUC IR 59.1.1

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ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab – Appendix B – Accounting Changes				
1	Losses on Disposal of Assets	Losses on Disposal of assets indicate: 1) That the Depreciation rates are insufficient to amortize the asset during its estimated useful life. (FortisBC states that the new depreciation study will be complete for the 2012 RRA.. 2) Accounting issues in recording accumulated depreciation: i.e. 2005 & 2009 vintage Transportation Equipment write-offs - there were no accumulated depreciation, thereby creating losses at retirement. Why?	FBC to file the updated Depreciation Study in the 2012 RRA (incl. the Iowa curves and any other references used in Depreciation Study), in addition to providing explanations to any losses that are greater than $100,000.	Exhibit B-1, Appendix B, pp.9-10, pp.12-13 Exhibit B-3, BCUC IR 61.1, 62.3
2	Major Inspection and Overhaul costs	IFRS IAS 16.14 requires companies to capitalize Major Inspection and Major Overhaul costs and depreciate over the life until the next inspection date.	In its 2012 RRA, FBC should provide a description of the accounting and depreciation treatment of Major Inspection costs.	Exhibit B-1, Appendix B, p.13 Exhibit B-3, BCUC IR 63.1
Tab – Appendix D – O&M Savings Report				
	Delay of Maintenance	In the 2011 Annual Review, stakeholders would like FBC to provide an analysis of whether any normal maintenance was delayed in 2011 into future RRAs.	In the 2011 Annual Review, FBC will provide an analysis on whether any normal maintenance was delayed in 2011 into future RRAs.	

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	ISSUE DESCRIPTION	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab – Appendix E – Capitalized Power Purchases				
	FBC has capitalized Upgrade Life Extension (ULE) Power Purchase costs on ULE's that have previously been approved.	ULE Power Purchase costs should be treated as incremental Power Purchase expense while the costs related to the upgrade is capital. Methodology to be adopted in future RRAs. According to CICA HB Section 3061.26, Betterment (ULE) may incur both operating and capital costs. Replacing lost capacity does not extend the life of the asset, it is required in order to maintain normal operations of the system while the asset is taken out of service. Furthermore, capitalization will be inconsistent with FBC's Capitalization Policy (no future benefit, does not extend life). Stakeholders recognize this was done in the past / during PBR so new methodology should be adopted in next RRA (2012).	FBC will treat ULE incremental power purchase costs as a power purchase expense beginning in 2012 on future ULE projects.	Exhibit B-1, Appendix E Exhibit B-3, BCUC IR 66.1-66.4 FortisBC Capitalization Policy
Other Issues				
1	FBC 2011 Capital Expenditure Plan Decision	FBC is to flow through any related rate impact as a result of the 2011 CEP Decision with a timely application to the BCUC for tariff approval for rates effective January 1, 2011. It is anticipated that the CEP Decision will be available beginning to mid-December.	FBC will incorporate the impacts of the Commission decision on the Company's 2011 Capital Plan Application into rates for January 1, 2011 if that decision is available. If the 2011 Capital Plan decision is not available in time for incorporation into January 1, 2011 rates, FBC will incorporate this decision as soon as reasonably possible thereafter.	

FortisBC Inc.
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ISSUE DESCRIPTION		ISSUE DESCRIPTION	RESOLUTION	REFERENCE
2	FBC has not provided Multi Year Rate Forecasts	The 2009 NSA (G-193-08) requires FBC to provide a multi-year rate forecast as part of its annual review. The multi-year rate forecast was supposed to cover (at a minimum) the remaining term of the PBR. FBC has not done so in any subsequent RRA filings.	FBC to provide a multi-year rate forecast as part of its next RRA, which includes forecast rate impacts from the Capital Expenditures Plan, Integrated System Plan, and Resource Plan. It is recognized that the Company will not be held responsible for its eventual accuracy. The 2012 application will have a forecast of expected rates for 2013, 2014, 2015 and 2016.	
3	Shaw	FBC has not included any forecast amounts in Other Income for 2011 relating to Shaw transmission attachments on FBC poles.	FBC is to treat this matter (Shaw transmission attachments) as a Z-factor and true-up any actual revenues at the 2011 Annual Review. Any true up will flow through 2012 FBC Rates.	Exhibit B-3, BCUC 5.5.1 Order G-58-06
4	Actuarial letter regarding Pension and Other Post Retirement Benefits	In FBC's December rate filing with the Commission, it is to include the impact of the Actuarial letter regarding Pension and Other Post Retirement Benefits.	FBC has included the impacts of the Actuarial letter regarding pension and other post retirement benefits in the financial schedules accompanying this NSA. The impact of the letter is a net increase of $43k to O&M and an after tax decrease of $151k to the deferral amount.	
5	Celgar Rate 33	FBC did not reflect the move of Celgar from Rate 33 to Rate 31 as per the COSA RDA decision. G-156-10	Increase Revenues by $450,000 to reflect the move of Celgar from Rate 33 to Rate 31 and true-up to actual revenues received from Celgar in 2011 at the 2011 Annual Review. The true up will flow through 2012 FBC rates.	

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2011 Performance Standards Targets

Performance Standard	2011 Target
All Injury Frequency Rate	2.05
Injury Severity Rate	15.96
Vehicle Incident Rate	1.60
SAIDI	2.69
SAIFI	2.10
Generator Forced Outage Rate	0.35%
Billing Accuracy	0.072%
Meters Read as Scheduled	97%
Contact Centre - calls within 30 seconds	70%
Emergency Response Time	85%
Residential Connections - within 6 days	85%
Residential Extensions - quoting time	96%
Residential Extensions - completion time	96%

FORTISBC

2011 Revenue Requirements Negotiated Settlement Agreement

Financial Schedules

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REVENUE REQUIREMENTS OVERVIEW

		Approved 2010	Increase or (Decrease)	Forecast 2011
			($000s)	
1	Sales Volume (GWh)	3,199		3,162
2	Rate Base	975,113		1,095,135
3	Return on Rate Base	7.73%		7.66%
4				
5	**REVENUE DEFICIENCY**			
6				
7	**POWER SUPPLY**			
8	Power Purchases	80,408	(1,441)	78,967
9	Water Fees	9,068	313	9,381
10		89,476	(1,128)	88,348
11	**OPERATING**			
12	O&M Expense	47,645	2,473	50,118
13	Capitalized Overhead	(9,529)	(495)	(10,024)
14	Wheeling	4,019	(681)	3,338
15	Other Income	(5,025)	(430)	(5,455)
16		37,109	868	37,977
17	**TAXES**			
18	Property Taxes	12,548	1,392	13,940
19	Income Taxes	5,407	491	5,898
20		17,955	1,883	19,838
21	**FINANCING**			
22	Cost of Debt	36,765	3,783	40,548
23	Cost of Equity	38,614	4,753	43,367
24	Depreciation and Amortization	42,028	3,470	45,498
25		117,407	12,006	129,413
26				
27	Prior Year Incentive True Up	(322)	(767)	(1,089)
28	Flow Through Adjustments	(1,068)	(1,061)	(2,129)
29	ROE Sharing Incentives	(1,300)	1,748	448
30		(2,690)	(80)	(2,770)
31				
32	**TOTAL REVENUE REQUIREMENT**	**259,258**	**13,549**	**272,806**
33				
34	Carrying Cost on Rate Base Deferral Account	17	(17)	-
35	**ADJUSTED REVENUE REQUIREMENT**	**259,274**	**13,532**	**272,806**
36	**LESS: REVENUE AT APPROVED RATES**	**242,031**		**259,358**
37	**REVENUE DEFICIENCY for Rate Setting**	**17,243**		**13,449**
38				
39	**RATE INCREASE**			**5.20%**

Note: Minor differences due to rounding.

SCHEDULE 1 – UTILITY RATE BASE

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
1	Plant in Service, January 1	1,165,457	1,273,476	1,417,415
2	Net Additions	108,019	143,939	154,898
3	Plant in Service, December 31	1,273,476	1,417,415	1,572,313
4				
5	Add:			
6	CWIP not subject to AFUDC	5,913	5,902	5,444
7	Plant Acquisition Adjustment	11,912	11,912	11,912
8	Deferred and Preliminary Charges	15,508	18,472	24,984
9				
10		1,306,809	1,453,701	1,614,653
11	Less:			
12	Accumulated Depreciation			
13	and Amortization	301,384	335,173	372,071
14	Contributions in Aid of Construction	90,267	94,168	100,504
15		391,651	429,340	472,575
16				
17	Depreciated Rate Base	915,158	1,024,361	1,142,078
18				
19	Prior Year Depreciated Utility Rate Base	838,899	915,158	1,024,361
20				
21	Mean Depreciated Utility Rate Base	877,029	969,759	1,083,219
22	Add:			
23	Allowance for Working Capital	7,231	6,303	5,474
24	Adjustment for Capital Additions	(16,577)	(30,312)	6,442
25				
26	**Mid-Year Utility Rate Base**	**867,683**	**945,750**	**1,095,135**

Note: Minor differences due to rounding.

Schedule 1A – Non Rate Base Assets

		BCUC Order No. [1]	Regulatory Asset / (Liability) Forecast 2011
			($000s)
	GAAP Related		
1	Deferred Income Taxes	G-37-84, G-193-08, G-162-09	101,089
2	Brilliant Terminal Station Capital Lease	G-2-04, G-193-08, G-162-09	5,635
3	Other Post-Retirement Benefits	G-52-05, G-193-08, G-162-09	3,339
4	Trail Office Building Lease Costs	G-41-93, G-193-08, G-162-09	1,104
5	Asset Retirement Obligation		1,071
6	Financing Costs Under Effective Interest Method		(800)
	IFRS Related [2]		
7	Capitalization of Depreciation on Assets Used in Construction	G-162-09	(1,000)
8	Pension and Employee Future Benefit Costs - Cumulative Unamortized Actuarial Gains and Losses Upon Transition	G-162-09	37,100
9	Brilliant Power Purchase Agreement Lease Costs		7,900
			155,438

The inclusion of Non Rate Base assets in the 2011 Revenue Requirements is discussed further in Appendix B to the October Preliminary Revenue Requirements Application dated October 1, 2010.

Note 1:
Deferral recognition has been approved through the Orders listed above.

Note 2:
As a result of further investigation into accounting differences and pending decisions made by international standard setters, there may be further deferrals associated with the transition to IFRS. Any further IFRS deferrals to be recognized in 2011 or 2012 will be requested for approval in the 2012 Revenue Requirements Application. See Appendix B to the October Preliminary Revenue Requirements Application dated October 1, 2010 for further details.

Note: Minor differences due to rounding.

Table 1 – A – Utility Plant in Service (2010)

Line	Account		December 31 2009	Additions	Retirements	December 31 2010
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	115	1,076
2	331	Structures and Improvements	12,014	328	439	12,782
3	332	Reservoirs, Dams & Waterways	24,444	5,305	1,855	31,604
4	333	Water Wheels, Turbines and Gen.	61,382	11,978	(3,419)	69,942
5	334	Accessory Equipment	27,493	4,981	(301)	32,174
6	335	Other Power Plant Equipment	40,893	914	236	42,043
7	336	Roads, Railroads and Bridges	1,287	-	234	1,522
8			**168,476**	**23,506**	**(840)**	**191,142**
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,205	883	10	8,097
11	350	Land Rights-Clearing	5,798	883	852	7,533
12	353	Station Equipment	138,235	24,360	(31,060)	131,536
13	355	Poles, Towers & Fixtures	72,627	26,133	(6,370)	92,390
14	356	Conductors and Devices	70,448	24,599	(6,241)	88,805
15	359	Roads and Trails	1,121	299	-	1,420
16			**295,435**	**77,156**	**(42,809)**	**329,781**
17		**Distribution Plant**				
18	360	Land Rights-R/W	2,456	1,528	(868)	3,117
19	360	Land Rights-Clearing	8,477	1,528	(742)	9,264
20	362	Station Equipment	181,231	24	31,843	213,098
21	364	Poles Towers & Fixtures	126,978	14,379	2,529	143,886
22	365	Conductors and Devices	208,987	10,360	6,754	226,101
23	368	Line Transformers	98,457	2,804	1,845	103,107
24	369	Services	7,292	2,523	-	9,815
25	370	Meters	13,277	1,175	(577)	13,875
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	10,275	-	1,691	11,965
28			**658,368**	**34,321**	**42,475**	**735,165**
29		**General Plant**				
30	389	Land	11,297	-	909	12,206
31	390	Structures-Frame & Iron	337	-	-	337
32	390	Structures-Masonry	26,083	1,015	(63)	27,035
33	391	Office Furniture & Equipment	5,475	800	(127)	6,148
34	391	Computer Equipment	56,886	5,854	71	62,811
35	392	Transportation Equipment	17,552	1,958	(1,353)	18,157
36	394	Tools and Work Equipment	10,869	615	(355)	11,129
37	397	Communication Structures and Equipment	22,698	2,070	(1,264)	23,504
38			**151,197**	**12,312**	**(2,182)**	**161,327**
39						
40	101	**Plant in Service**	**1,273,476**	**147,295**	**(3,356)**	**1,417,415**
41	107	Plant under construction not subject				
42		to AFUDC	5,913			5,902
43	107	Plant under construction				
44		subject to AFUDC	52,429			57,264
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46						
47	105	Utility Plant per Balance Sheet	**1,343,729**			**1,492,494**

Note: Minor differences due to rounding.

Table 1 – A – Utility Plant in Service (2011)

Line	Account		December 31 2010	Additions	Retirements	December 31 2011
		Hydraulic Production Plants		(000s)		
1	330	Land Rights	1,076	-	115	1,191
2	331	Structures and Improvements	12,782	177	439	13,398
3	332	Reservoirs, Dams & Waterways	31,604	311	1,855	33,770
4	333	Water Wheels, Turbines and Gen.	69,942	9,914	(3,419)	76,437
5	334	Accessory Equipment	32,174	4,802	(301)	36,676
6	335	Other Power Plant Equipment	42,043	19,163	236	61,442
7	336	Roads, Railroads and Bridges	1,522	-	234	1,756
8			**191,142**	**34,367**	**(840)**	**224,669**
9		**Transmission Plant**				
10	350	Land Rights-R/W	8,097	589	10	8,696
11	350	Land Rights-Clearing	7,533	589	852	8,974
12	353	Station Equipment	131,536	64,940	(31,060)	165,416
13	355	Poles Towers & Fixtures	92,390	2,123	(6,370)	88,143
14	356	Conductors and Devices	88,805	703	(6,241)	83,267
15	359	Roads and Trails	1,420	-	-	1,420
16			**329,781**	**68,944**	**(42,809)**	**355,916**
17		**Distribution Plant**				
18	360	Land Rights-R/W	3,117	2,424	(868)	4,673
19	360	Land Rights-Clearing	9,264	2,424	(742)	10,945
20	362	Station Equipment	213,098	541	31,843	245,483
21	364	Poles Towers & Fixtures	143,886	10,439	2,529	156,853
22	365	Conductors and Devices	226,101	9,816	6,754	242,671
23	368	Line Transformers	103,107	3,091	1,845	108,043
24	369	Services	9,815	4,272	-	14,087
25	370	Meters	13,875	1,178	(577)	14,476
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,965	-	1,691	13,656
28			**735,165**	**34,185**	**42,475**	**811,825**
29		**General Plant**				
30	389	Land	12,206	-	909	13,114
31	390	Structures-Frame & Iron	337	-	-	337
32	390	Structures-Masonry	27,035	3,599	(63)	30,571
33	391	Office Furniture & Equipment	6,148	176	(127)	6,197
34	391	Computer Equipment	62,811	8,420	71	71,302
35	392	Transportation Equipment	18,157	2,000	(1,353)	18,805
36	394	Tools and Work Equipment	11,129	1,291	(355)	12,065
37	397	Communication Structures and Equipment	23,504	5,272	(1,264)	27,513
38			**161,327**	**20,758**	**(2,182)**	**179,903**
39						
40	101	**Plant in Service**	**1,417,415**	**158,254**	**(3,356)**	**1,572,313**
41	107	Plant under construction not subject				
42		to AFUDC	5,902			5,444
43	107	Plant under construction				
44		subject to AFUDC	57,264			3,385
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46						
47	105	Utility Plant per Balance Sheet	**1,492,494**			**1,593,054**

Note: Minor differences due to rounding.

Table 1 – A – 1 – Additions to Plant in Service (2010)

		CWIP Dec. 31, 2009	Expenditures 2010	CWIP Dec 31, 2010	Additions to Plant in Service
				(000s)	
	Hydraulic Production				
1	All Plants Spare Unit Transformer	-	113	-	113
2	LBO & UBO Comm. Network Comp.	86	281	-	367
3	All Plants Fire Safety Upgrade Ph.1	40	43	-	83
4	SLC U1 Life Extension (replace turbine)	13,751	1,793	-	15,544
5	SLC U1 Head Gate Rebuild	681	92	-	773
6	All Plants Public Safety & Security Ph.1	11	99	-	110
7	P3 Poleyard Contaminated Site	-	(23)	-	(23)
8	P1 P4 Capital Planning 2008 Project	1	(1)	-	-
9	UBO Old Unit Repowering (Ph.1)	-	298	-	298
10	All Plants Upgrade Station Service Supply	226	1,395	59	1,562
11	SLC H/G Hoist, Control, Wire Rope Upgrade	945	145	-	1,090
12	SLC Plant Completion	1,688	697	-	2,385
13	COR U1 Life Extension (replace Turbine)	3,363	10,269	13,632	-
14	COR U2 Life Extension (replace Turbine)	33	3,314	3,347	-
15	SLC Dam Rehabilitation Study	4	30	-	34
16	UBO Extension Trash Rack Gantry Replacement	-	364	-	364
17	All Plants Spare Exciter Transformer	31	105	-	136
18	LBO Intake Area Upgrade Ph.2	-	35	-	35
19	SLC Domestic Water Supply Ph.3	40	48	88	-
20	All Plants 2009 Pump Upgrades	130	80	-	210
21	All Plants Lighting Upgrade	-	266	-	266
22	SLC Tailrace Gate Corrosion Control	-	131	-	131
23	Queen's Bay Level Gauge Building Ph.1	14	15	-	29
24		**21,045**	**19,587**	**17,126**	**23,506**
25					
	Transmission Plant				
26	Ellison Distribution Source	-	220	-	220
27	Black Mountain Distribution Source	-	32	-	32
28	Okanagan Transmission Reinforcement	24,456	56,268	38,507	42,217
29	Benvoulin Distribution Source	4,110	12,605	-	16,715
30	Naramata Rehab	-	(462)	-	(462)
31	Huth Split Bus	-	241	241	-
32	Capitalized Inventory	5,913	(820)	5,093	-
33	Recreation Capacity Increase Stage 1,2,3	179	3,822	100	3,901
34	Tarry's Capacity Increase	265	51	-	316
35	Kelowna Distribution Capacity Requirements	271	626	-	897
36	30L Conversion Slocan / Coffee Creek S/Stns	866	4,272	-	5,138
37	Transmission Sustaining	(12)	4,225	-	4,213
38	Station Sustaining	5	4,368	404	3,969
39		**36,052**	**85,448**	**44,345**	**77,156**
40					
	Distribution Plant				
41	Small Capacity Improvements Unplanned	-	789	-	789
42	New Connects System Wide	-	16,819	-	16,819
43	New Glenmore Feeder	487	121	-	608
44	Airport Way Upgrade (Ellison Feeder - 3)	-	1,396	-	1,396
45	Oliver Feeder-1 New Regulator	-	140	-	140
46	Beaver Park Feeder-2 to Fruitvale Feeder-1 Distribu	22	849	-	871
47	Distrlbution Sustaining	-	13,699	-	13,699
48		**509**	**33,813**	**-**	**34,321**
49					
	General Plant				
50	Distribution Station Automation	725	1,765	406	2,084
51	Protection & Communications Upgrades	-	642	-	642
52	Mandatory Reliability Compliance (MRC)	-	2,000	1,290	710
53	Vehicles	-	1,958	-	1,958
54	Metering	-	558	-	558
55	Information Systems	-	4,336	-	4,336
56	Telecommunications	-	91	-	91
57	Buildings	-	1,062	-	1,062
58	Furniture & Fixtures	-	354	-	354
59	Tools & Equipment	-	517	-	517
60		**725**	**13,283**	**1,696**	**12,312**
61					
62	**TOTAL**	**58,330**	**152,131**	**63,167**	**147,295**
63	Less Closing CWIP subject to AFUDC			**57,264**	
64	Total CWIP not subject to AFUDC			**5,902**	

Note: Minor differences due to rounding.

Table 1 – A – 1 – Additions to Plant in Service (2011)

		CWIP Dec. 31, 2010	Expenditures 2011	CWIP Dec 31, 2011	Additions to Plant in Service
			(000s)		
	Hydraulic Production				
1	SLC Plant Automation	-	243	-	243
2	SLC Fire Panel	-	266	-	266
3	UBO Spillgate Rebuild / Upgrade	-	610	610	-
4	LBO Power House Windows	-	351	351	-
5	All Plants Minor Sustaining Projects	-	957	-	957
6	SLC U1 Life Extension (replace turbine)	-	41	-	41
7	All Plants Upgrade Station Service Supply	59	1,309	467	901
8	COR U1 Life Extension (replace Turbine)	13,632	2,433	-	16,065
9	COR U2 Life Extension (replace Turbine)	3,347	12,373	-	15,720
10	SLC Domestic Water Supply Ph.3	88	-	-	88
11	LBO & UBO Plant Totalizer Upgrade	-	86	-	86
12		**17,126**	**18,669**	**1,428**	**34,367**
13					
	Transmission Plant				
14	Ellison Sexsmith Transmission Tie	-	667	667	-
15	Okanagan Transmission Reinforcement	38,507	17,938	-	56,445
16	Benvoulin Distribution Source	-	130	-	130
17	Huth Split Bus	241	4,674	-	4,915
18	Capitalized Inventory & Transformers	5,093	-	5,093	-
19	Transmission Sustaining	-	3,607	-	3,607
20	Station Sustaining	404	3,343	-	3,747
21		**44,345**	**30,359**	**5,760**	**68,944**
22					
	Distribution Plant				
23	Gross New Connects System Wide	-	21,162	-	21,162
24	Distribution Unplanned Growth Projects	-	948	-	948
25	Distrlbution Sustaining	-	12,075	-	12,075
26		**-**	**34,185**	**-**	**34,185**
27					
	General Plant				
28	Distribution Station Automation	406	1,540	-	1,946
29	GFT to Warfield Fibre Installation	-	667	667	-
30	Kelowna 138kV Loop Fibre Installation	-	3,382	-	3,382
31	Protection, Harmonic Remediation, Communications & Rehabilitation	-	1,551	-	1,551
32	Mandatory Reliability Compliance (MRC)	1,290	595	-	1,885
33	Vehicles	-	2,000	-	2,000
34	Metering	-	213	0	213
35	Information Systems	-	5,550	-	5,550
36	Telecommunications	-	358	-	358
37	Buildings	-	1,244	-	1,244
38	Kootenay Operations Centre	-	485	485	-
39	Okanagan Long Term Solution	-	489	489	-
40	PCB Environmental Compliance	-	1,852	-	1,852
41	Furniture & Fixtures	-	176	-	176
42	Tools & Equipment	-	601	-	601
43		**1,696**	**20,703**	**1,641**	**20,758**
44					
45	**TOTAL**	**63,167**	**103,916**	**8,829**	**158,254**
46	Less Closing CWIP subject to AFUDC			**3,385**	
47	Total CWIP not subject to AFUDC			**5,444**	

Note: Minor differences due to rounding.

Table 1 – B – Deferred Charges and Credits (2010)

		Balance at Dec. 31, 2009	Additions and Transfers	Amortized / Transferred to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2010
1	**Demand Side Management**					
2	Demand Side Management Additions	20,518	3,700	-	(3,272)	20,946
3	Tax Impact	(12,402)	(1,055)	-	933	(12,524)
4		**8,116**	**2,646**	**-**	**(2,339)**	**8,422**
5						
6	**Preliminary and Investigative Charges**	**1,089**	**2,701**	**(528)**	**-**	**3,261**
7						
8	**Deferred Regulatory Expense**					
9	2008 Incentive	(322)	-	322	-	-
10	2009 Incentive	(3,458)	-	2,368	-	(1,090)
11	2010 Incentive	-	**(1,681)**	-	-	(1,681)
12	Shaw Application for Transmission Facility Access	-	325	-	-	325
13	Tax Impact	-	(93)	-	-	(93)
14	2009 Revenue Requirements	43	-	-	(43)	-
15	Tax Impact	(13)	-	-	13	-
16	2010 Revenue Requirements	17	58	-	-	75
17	Tax Impact	(5)	(17)	-	-	(22)
18	2011 Revenue Requirements	-	80	-	-	80
19	Tax Impact	-	(23)	-	-	(23)
20	COSA & RDA	763	1,210	-	-	1,973
21	Tax Impact	(233)	(345)	-	-	(578)
22	BC Hydro Amendment to 3808 (PPA Proceedings)	114	-	-	(38)	76
23	Tax Impact	(35)	-	-	12	(23)
24	Section-5 Provincial Transmission Enquiry	82	7	-	-	89
25	Tax Impact	(25)	(2)	-	-	(27)
26	Renew BCH Power Purchase Agreement	105	25	-	-	130
27	Tax Impact	(32)	(7)	-	-	(39)
28	BC Hydro Waneta Transaction Application	255	29	-	-	284
29	Tax Impact	(77)	(8)	-	-	(85)
30	Terasen Gas ROE Application	92	-	-	-	92
31	Tax Impact	(28)	-	-	-	(28)
32		**(2,755)**	**(441)**	**2,690**	**(56)**	**(563)**
33						
34						
35						
36	**Other Deferred Charges and Credits**					
37	Trail Office Lease Costs	167	-	-	(12)	155
38	Trail Office Rental to SD#20	(679)	-	(50)	-	(729)
39	Prepaid Pension Costs	8,916	(1,442)	-	-	7,474
40	Tax Impact	(1,176)	411	-	-	(765)
41	Post Retirement Benefits	(7,702)	(2,599)	-	-	(10,301)
42	Tax Impact	2,465	741	-	-	3,206
43	2008 System Development Plan Update	569	-	-	(569)	-
44	Tax Impact	(180)	-	-	180	-
45	Tax Impact	(0)	-	-	-	(0)
46	2008 Resource Plan Update	412	-	-	-	412
47	Tax Impact	(134)	-	-	-	(134)
48	2009 Resource Plan Update	157	391	-	-	548
49	Tax Impact	(47)	(111)	-	-	(158)
50	ISP 2012-31	-	350	-	-	350
51	Tax Impact	-	(100)	-	-	(100)
52	Revenue Protection	162	230	-	(162)	230
53	Tax Impact	(48)	(66)	-	48	(66)
54	PLP Settlement Costs	16	-	-	(16)	-
55	PLP Computer Software	63	-	-	(23)	40
56	PLP Deferred Pension Credit	(58)	-	-	12	(46)
57	ROW Reclamation (Pine Beetle Kill)	2,257		-	(251)	2,006
58	Tax Impact	(700)	-	-	78	(622)
59	International Financial Reporting Standards	304	205	-	(304)	205
60	Tax Impact	(91)	(58)	-	91	(58)
61	Right of Way Encroachment Litigation	82	40	-	-	122
62	Tax Impact	(25)	(11)	-	-	(37)
63	HST Project	-	250	-	-	250
64	Tax Impact	-	(71)	-	-	(71)
65	Capital Expenditure Plan (CEP) 2011	182	(182)	-	-	-
66	Tax Impact	(54)	54	-	-	-
67	DSM Study	96	169	-	-	265
68	Tax Impact	(29)	(48)	-	-	(77)
69	Joint Pole Use Audit 2008	124	-	-	(31)	93
70	Tax Impact	(37)	-	-	9	(28)
71	Section 71 Filing (Waneta Exp. Proj. Power Pch. Agr.)	-	400	-	-	400
72	Tax Impact	-	(114)	-	-	(114)
73	Pope & Talbot Litigation	-	40			40
74	Tax Impact	-	(11)			(11)
75	NERC / MRC Set up Cost	27	773	-	-	800
76	Tax Impact	(8)	(220)	-	-	(228)
77		**5,028**	**(980)**	**(50)**	**(949)**	**3,049**
78	**Deferred Debt Issue Costs**					
79	Series F	105	-	-	(35)	70
80	Series G	100	-	-	(9)	92
81	Series H	79	-	-	(13)	65
82	Series I	171	-	-	(15)	156
83	Series 04-1	1,072	-	-	(214)	858
84	Tax Impact	(76)	-	-	11	(64)
85	Series 05-1	1,073	-	-	(41)	1,033
86	Tax Impact	(391)	-	-	14	(377)
87	Series 07-1	1,184	-	-	(32)	1,152
88	Tax Impact	(242)	(87)	-	5	(324)
89	MTN-2009	1,016	-	-	(34)	982
90	Tax Impact	(61)	(61)	-	2	(120)
91	MTN-2010	-	825	-	-	825
92	Tax Impact	-	(47)	-	-	(47)
93		**4,030**	**630**	**-**	**(359)**	**4,302**
94						
95	TOTAL DEFERRED CHARGES RATE BASE	**15,508**	**4,555**	**2,112**	**(3,703)**	**18,472**
96						
97	Automated Meter Reading Feasibility Study	465	630	-	-	1,095
98	Tax Impact	(144)	144	-	-	-
99		**15,829**	**5,329**	**2,112**	**(3,703)**	**19,566**

Note: In the terms of the NSA of November 2010 the AMI development costs are being recorded in a non-rate base deferral account that wil attract AFUDC

Note: Minor differences due to rounding.

Table 1 – B – Deferred Charges and Credits (2011)

		Balance at Dec. 31, 2010	Additions and Transfers	Amortized / Transferred to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2011
1	**Demand Side Management**					
2	Demand Side Management Additions	20,946	7,842	-	(1,859)	26,930
3	Tax Impact	(12,524)	(2,078)	-	493	(14,110)
4		**8,422**	**5,764**	**-**	**(1,366)**	**12,820**
5						
6	**Preliminary and Investigative Charges**	**3,261**	**2,059**	**(582)**	**-**	**4,738**
7						
8	**Deferred Regulatory Expense**	-				-
9	2009 Incentive	(1,090)	-	1,090	-	-
10	2010 Incentive	(1,681)	-	1,681	-	-
11	Shaw Application for Transmission Facility Access	325	-	-	-	325
12	Tax Impact	(93)	-	-	-	(93)
13	2010 Revenue Requirements	75	-	-	(75)	-
14	Tax Impact	(22)	-	-	22	-
15	2011 Revenue Requirements	80	-	-	-	80
16	Tax Impact	(23)	-	-	-	(23)
17	COSA & RDA	1,973	200	-	(543)	1,629
18	Tax Impact	(578)	(53)	-	158	(473)
19	BC Hydro Amendment to 3808 (PPA Proceedings)	76	-	-	(38)	38
20	Tax Impact	(23)	-	-	12	(12)
21	Section-5 Provincial Transmission Enquiry	89	-	-	(89)	-
22	Tax Impact	(27)	-	-	27	-
23	Renew BCH Power Purchase Agreement	130	155	-	-	285
24	Tax Impact	(39)	(41)	-	-	(80)
25	BC Hydro Waneta Transaction Application	284	-	-	(95)	190
26	Tax Impact	(85)	-	-	28	(57)
27	Terasen Gas ROE Application	92	-	-	(92)	-
28	Tax Impact	(28)	-	-	28	-
29		**(563)**	**261**	**2,771**	**(658)**	**1,810**
30						-
31	**Other Deferred Charges and Credits**					-
32	Trail Office Lease Costs	155	-	-	(12)	143
33	Trail Office Rental to SD#20	(729)	-	(57)	-	(786)
34	Prepaid Pension Costs	7,474	(225)	-	-	7,249
35	Tax Impact	(765)	60	-	-	(705)
36	Post Retirement Benefits	(10,301)	(2,823)	-	-	(13,124)
37	Tax Impact	3,206	748	-	-	3,954
38	2008 Resource Plan Update	412	(412)	-	-	-
39	Tax Impact	(134)	134	-	-	-
40	2009 Resource Plan Update	548	(548)	-	-	-
41	Tax Impact	(158)	158	-	-	-
42	ISP 2012-31	350	3,110	-	-	3,460
43	Tax Impact	(100)	(863)	-	-	(962)
44	Revenue Protection	230	235	-	(230)	235
45	Tax Impact	(66)	(62)	-	66	(62)
46	PLP Computer Software	40	-	-	(23)	17
47	PLP Deferred Pension Credit	(46)	-	-	12	(35)
48	ROW Reclamation (Pine Beetle Kill)	2,006		-	(251)	1,755
49	Tax Impact	(622)	-	-	78	(544)
50	International Financial Reporting Standards	205	175	-	(205)	175
51	Tax Impact	(58)	(46)	-	58	(46)
52	Right of Way Encroachment Litigation	122	-	-	-	122
53	Tax Impact	(37)	-	-	-	(37)
54	HST Project	250	-	-	(250)	-
55	Tax Impact	(71)	-	-	71	-
56	DSM Study	265	-	-	(88)	177
57	Tax Impact	(77)	-	-	26	(51)
58	Joint Pole Use Audit 2008	93	-	-	(31)	62
59	Tax Impact	(28)	-	-	9	(19)
60	Section 71 Filing (Waneta Exp. Proj. Power Pch. Agr.)	400	-	-	(133)	267
61	Tax Impact	(114)	-	-	38	(76)
62	Pope & Talbot Litigation	40			(40)	-
63	Tax Impact	(11)			11	-
64	NERC / MRC Set up Cost	800	200	-	-	1,000
65	Tax Impact	(228)	(53)	-	-	(281)
66		**3,049**	**(212)**	**(57)**	**(895)**	**1,886**
67	**Deferred Debt Issue Costs**					
68	Series F	70	-	-	(35)	35
69	Series G	92	-	-	(9)	83
70	Series H	65	-	-	(13)	52
71	Series I	156	-	-	(15)	142
72	Series 04-1	858	-	-	(214)	644
73	Tax Impact	(64)	-	-	11	(53)
74	Series 05-1	1,033	-	-	(41)	992
75	Tax Impact	(377)	-	-	14	(362)
76	Series 07-1	1,152	-	-	(32)	1,121
77	Tax Impact	(324)	(87)	-	8	(402)
78	MTN-2009	982	-	-	(34)	948
79	Tax Impact	(120)	(61)	-	4	(177)
80	MTN-2010	825	-	-	(28)	798
81	Tax Impact	(47)	(47)	-	3	(91)
82		**4,302**	**(195)**	**-**	**(378)**	**3,729**
83						
84	TOTAL DEFERRED CHARGES RATE BASE	**18,472**	**7,677**	**2,132**	**(3,297)**	**24,984**
85						
86	Automated Meter Reading Feasibility Study	1,095	706	-		1,801
87		**19,566**	**8,383**	**2,132**	**(3,297)**	**26,784**

Note: Minor differences due to rounding.

Table 1 – C – Accumulated Provision for Depreciation and Amortization (2010)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2009	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	115	(455)
2	331	Structures and Improvements	5,211	1.2%	12,014	150	423	5,785
3	332	Reservoirs, Dams and Waterways	5,165	1.7%	24,444	417	1,597	7,179
4	333	Water Wheels, Turbines & Generators	1,092	2.2%	61,382	1,353	(4,002)	(1,557)
5	334	Accessory Electrical Equipment	7,568	2.4%	27,493	659	(543)	7,684
6	335	Other Power Plant Equipment	8,299	2.3%	40,893	949	192	9,440
7	336	Roads, Railroads, and Bridges	468	1.4%	1,287	18	234	721
8			**27,208**	**2.1%**	**168,476**	**3,572**	**(1,984)**	**28,796**
9		Transmission Plant						-
10	350	Land Rights - R/W	(62)	0.0%	7,205	-	10	(52)
11	350	Land Rights - Clearing	1,965	1.6%	5,798	93	852	2,910
12	353	Station Equipment	(1,212)	3.0%	138,235	4,157	(32,130)	(29,184)
13	355	Poles Towers & Fixtures	11,125	3.0%	72,627	2,184	(7,518)	5,792
14	356	Conductors and Devices	7,494	3.0%	70,448	2,118	(7,322)	2,290
15	359	Roads and Trails	56	2.9%	1,121	33	(13)	76
16			**19,366**	**2.9%**	**295,435**	**8,587**	**(46,120)**	**(18,168)**
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	2,456	-	(868)	(1,735)
19	360	Land Rights - Clearing	(206)	2.1%	8,477	178	(742)	(769)
20	362	Station Equipment	64,884	3.0%	181,231	5,451	31,843	102,178
21	364	Poles Towers & Fixtures	38,145	3.0%	126,978	3,819	2,320	44,283
22	365	Conductors and Devices	58,365	3.0%	208,987	6,286	6,604	71,254
23	368	Line Transformers	19,318	2.9%	98,457	2,862	1,805	23,984
24	369	Services	6,475	0.0%	7,292	-	(37)	6,439
25	370	Meters	5,034	3.5%	13,277	463	(594)	4,903
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	248	1,691	5,321
28			**191,117**	**2.9%**	**658,368**	**19,307**	**42,021**	**252,445**
29		General Plant						
30	389	Land	897	0.0%	11,297	-	909	1,806
31	390	Structures - Frame & Iron	533	0.8%	337	3	-	536
32	390	Structures - Masonry	3,543	3.0%	21,752	653	(66)	4,130
33	391	Office Furniture & Equipment	3,831	7.5%	5,475	412	(129)	4,114
34	391	Computer Equipment	35,610	10.6%	56,886	6,064	56	41,730
35	392	Transportation Equipment	2,049	0.4%	17,552	70	(1,358)	761
38	394	Tools and Work Equipment	6,247	9.5%	10,869	1,036	(357)	6,926
39	397	Communication Structures and Equipment	5,956	6.0%	22,698	1,365	(1,270)	6,051
40			**58,666**	**6.5%**	**146,866**	**9,603**	**(2,214)**	**66,056**
41								
42	108	Total Accumulated Depreciation	296,357	3.2%	1,269,145	41,068	(8,297)	329,129
43								
44		Deduct - Portion of CIAC Depreciated	-			(4,000)		
45								
46	403	Depreciation Expense				37,068		
47								
48		Other						
49	114	Utility Plant Acquisition Adjustment	4,838		11,912	186		5,024
50	390	Leasehold Improvements	2,054		4,331	520		2,574
51		Rate Stabilization Adjustment	(1,865)			311		(1,554)
52		Total Accumulated Amortization	**5,027**			**1,017**		**6,044**
53								
54		Accumulated Amortization per						
55		Balance Sheet	**301,384**			**38,085**		**335,173**

Note: Minor differences due to rounding.

Table 1 – C – Accumulated Provision for Depreciation and Amortization (2011)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2010	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	(455)	2.6%	1,076	28	115	(313)
2	331	Structures and Improvements	5,785	1.2%	12,782	159	435	6,379
3	332	Reservoirs, Dams and Waterways	7,179	1.7%	31,604	537	1,847	9,563
4	333	Water Wheels, Turbines & Generators	(1,557)	2.2%	69,942	1,539	(3,693)	(3,711)
5	334	Accessory Electrical Equipment	7,684	2.4%	32,174	769	(433)	8,020
6	335	Other Power Plant Equipment	9,440	2.3%	42,043	974	(294)	10,121
7	336	Roads, Railroads, and Bridges	721	1.4%	1,522	21	234	976
8			**28,796**	**2.1%**	**191,142**	**4,027**	**(1,790)**	**31,034**
9		Transmission Plant	-					-
10	350	Land Rights - R/W	(52)	0.0%	8,097	-	10	(42)
11	350.1	Land Rights - Clearing	2,910	1.6%	7,533	121	852	3,883
12	353	Station Equipment	(29,184)	3.0%	131,536	3,946	(34,120)	(59,357)
13	355	Poles Towers & Fixtures	5,792	3.0%	92,390	2,772	(6,470)	2,094
14	356	Conductors and Devices	2,290	3.0%	88,805	2,664	(6,275)	(1,320)
15	359	Roads and Trails	76	2.9%	1,420	41	-	117
16			**(18,168)**	**2.9%**	**329,781**	**9,544**	**(46,002)**	**(54,626)**
17		Distribution Plant						
18	360	Land Rights - R/W	(1,735)	0.0%	3,117	-	(868)	(2,603)
19	360.1	Land Rights - Clearing	(769)	2.1%	9,264	195	(742)	(1,316)
20	362	Station Equipment	102,178	3.0%	213,098	6,393	31,809	140,380
21	364	Poles Towers & Fixtures	44,283	3.0%	143,886	4,317	1,865	50,465
22	365	Conductors and Devices	71,254	3.0%	226,101	6,783	6,130	84,167
23	368	Line Transformers	23,984	2.9%	103,107	2,990	1,649	28,623
24	369	Services	6,439	0.0%	9,815	-	(272)	6,167
25	370	Meters	4,903	3.5%	13,875	482	(652)	4,733
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	5,321	2.4%	11,965	287	1,691	7,298
28			**252,445**	**2.9%**	**735,165**	**21,447**	**40,609**	**314,501**
29		General Plant						
30	389	Land	1,806	0.0%	12,206	-	909	2,715
31	390	Structures - Frame & Iron	536	0.8%	337	3	-	539
32	390.1	Structures - Masonry	4,130	3.0%	22,148	662	(95)	4,697
33	391	Office Furniture & Equipment	4,114	7.5%	6,148	461	(128)	4,447
34	391.1	Computer Equipment	41,730	10.6%	62,811	6,679	(3)	48,407
35	392	Transportation Equipment	761	0.4%	18,157	73	(1,370)	(536)
36	362	Station Equipment	-	0.0%	-	-	-	-
37	370	Meters	-	0.0%	-	-	-	-
38	394	Tools and Work Equipment	6,926	9.5%	11,129	1,057	(366)	7,616
39	397	Communication Structures and Equipme	6,051	6.0%	23,504	1,410	(1,311)	6,150
40			**66,056**	**6.6%**	**156,440**	**10,345**	**(2,365)**	**74,035**
41								
42	108	Total Accumulated Depreciation	329,129	3.2%	1,412,528	45,363	(9,548)	364,944
43								
44		Deduct - Portion of CIAC Depreciated				(4,245)		
45								
46	403	Depreciation Expense				41,118		
47								
48		Other						
49	114	Utility Plant Acquisition Adjustment	5,024	1.56%	11,912	186		5,210
50	390	Leasehold Improvements	2,574	12.0%	4,887	586		3,160
51		Rate Stabilization Adjustment	(1,554)	10.0%		311		(1,243)
52		Manual entry for buy out of lease	-					-
53		Total Accumulated Amortization	**6,044**			**1,083**		**7,127**
54								
55		Accumulated Amortization per						
56		Balance Sheet	**335,173**			**42,201**		**372,071**

Note: Minor differences due to rounding.

Table 1 – D – Contributions in Aid of Construction (CIAC)

	Actual	Forecast		Forecast	
	Dec. 31 2009	2010 Additions	Dec. 31 2010	2011 Additions	Dec. 31 2011
			($000s)		
1 Gross Book Value	129,032	7,901	136,933	10,581	147,514
2 Accumulated Depreciation	(38,765)	(4,000)	(42,765)	(4,245)	(47,010)
3 Net Book Value	**90,267**		**94,168**		**100,504**

Note: Minor differences due to rounding.

Table 1 – E – Allowance for Working Capital (2011)

Line	Lag Days Calculation	Lag (Lead) Days	2011 Forecast ($000)	2011 Extended ($M)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	50.6	272,806	13,804	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	2,882	77	
5	Contract Revenue	44.3	1,499	66	
6	Miscellaneous Revenue	31.8	899	29	
7	Investment Income	15.0	175	3	
8			**$ 278,261**	**$ 13,978**	**50.2**
9					
10	**Expenses**				
11	Power Purchases	42.2	78,967	3,332	
12	Wheeling	40.2	3,338	134	
13	Water Fees	(1.0)	9,381	(9)	
14	*Operating Labour:*			0	
15	Salaries & Wages	5.3	14,383	76	
16	Employee Benefits	13.2	10,787	142	
17	Contracted Manpower	50.6	5,080	257	
18	Property Tax	2.6	13,940	36	
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	3,374	154	
23	Insurance	(182.5)	1,399	(255)	
24	Income Tax	15.2	5,898	90	
25	Interest	82.9	40,548	3,361	
26			**$ 192,166**	**$ 7,561**	**39.3**
27					
28	**Net Lag/(Lead) Days**				**10.9**
29					
30					
31	**Forecast Working Capital Allowance**				
32					
33	**Lead-Lag Study Allowance**				$ 5,732
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			2,784	
38	Employee Loans			419	
39	Uncollectable Accounts			1,056	
40	Inventory (forecast monthly average investment)			483	
41					$ 4,742
42	**Less Funds Available:**				
43	Average Customer Deposits			4,100	
44	Average Provincial Services Tax			400	
45	Average Goods and Services Tax			500	
46					$ 5,000
47					
48	**2011 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**$ 5,474**

Note: Minor differences due to rounding.

Table 1 – F – Adjustment for Capital Expenditures (2011)

		Plant in Service	Months in Rate Base	Weighted Value
		($000s)		($000s)
1	January	11,616	11.5	11,132
2	February	14,520	10.5	12,705
3	March	17,424	9.5	13,794
4	April	18,611	8.5	13,183
5	May	16,806	7.5	10,504
6	June	15,000	6.5	8,125
7	July	6,385	5.5	2,926
8	August	5,453	4.5	2,045
9	September	4,521	3.5	1,319
10	October	10,270	2.5	2,140
11	November	15,353	1.5	1,919
12	December	11,715	0.5	488
13	**Total**	**147,673**		**80,278**
14	**Less Simple Average**			73,836
15	**Adjustment to Rate Base**			**6,442**

16 Note: Plants in Service are reduced by Contributions in Aid of Construction

Note: Minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Actual 2009	Forecast 2010	Forecast 2011
1	SALES VOLUME (GWh)	3,157	3,078	3,162
2				
3			($000s)	
4	ELECTRICITY SALES REVENUE	238,572	249,721	272,806
5				
6	EXPENSES			
7	Power Purchases	70,776	73,573	78,967
8	Water Fees	8,656	9,250	9,381
9	Wheeling	4,003	4,021	3,338
10	Net O&M Expense	36,702	37,616	40,094
11	Property Tax	11,573	12,250	13,940
12	Depreciation and Amortization	37,376	41,788	45,498
13	Other Income	(5,187)	(6,532)	(5,455)
14	Incentive Adjustments	2,014	(1,009)	(2,770)
15	UTILITY INCOME BEFORE TAX	72,659	78,764	89,813
16	Less:			
17	INCOME TAXES	4,749	5,100	5,898
18				
19	EARNED RETURN	**67,910**	**73,664**	**83,915**
20	RETURN ON RATE BASE			
21	Utility Rate Base	867,683	945,750	1,095,135
22	Return on Rate Base	7.83%	7.79%	7.66%

Note: Minor differences due to rounding.

Table 2 – A – 1 –Sales by Customer Class

		Actual 2009	Forecast 2010	Forecast 2011
			(GWh)	
1	Residential	1,293	1,210	1,261
2	General Service	672	678	671
3	Industrial	203	243	233
4	Wholesale	928	891	940
5	Lighting	13	13	12
6	Irrigation	48	43	45
7	Total Sales	3,157	3,078	3,162
8	Losses and Company Use	322	276	310
9	**Gross Load**	**3,479**	**3,354**	**3,472**

Table 2 – A – 2 – Sales Revenue by Customer Class

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
10	Residential	112,059	116,906	120,615
11	General Service	57,798	59,987	62,795
12	Industrial	14,051	16,304	15,886
13	Wholesale	49,946	51,863	55,237
14	Lighting and Irrigation	4,717	4,661	4,823
15	**Total**	**238,572**	**249,721**	**259,358**

Note: Forecast 2011 Sales Revenue is in prior year's (2010) rates.

Table 2 – A – 3 – Customer Count at Year-End

		Actual 2009	Forecast 2010	Forecast 2011
16	Residential	96,565	97,956	99,663
17	General Service	11,308	11,440	11,714
18	Wholesale	7	7	7
19	Industrial	33	35	35
20	Lighting & Irrigation	2,940	2,917	2,917
21	**Total**	**110,853**	**112,355**	**114,336**

Note: Minor differences due to rounding.

Table 2 – B – Power Purchase Expense

		Actual 2009	Forecast 2010	Forecast 2011
			GWh	
1	FortisBC	1,586	1,533	1,597
2	DSM	-	8	29
3	Power Purchases (net of surplus sales)	1,893	1,822	1,875
4	Total System Load (before DSM savings)	3,479	3,362	3,501
5	Less DSM	-	(8)	(29)
6	**Total System Load**	**3,479**	**3,354**	**3,472**
			($000s)	
7	Expense - Energy	59,148	62,503	64,901
8	Expense - Capacity	11,969	12,961	15,413
9	Capital Projects, Accounting & other Adjustments	(341)	(1,891)	(1,347)
10	**Total Power Purchase Expense**	**70,776**	**73,573**	**78,967**

Note: Minor differences due to rounding.

Table 2 – C – Water Fees

		Actual 2009	Forecast 2010	Forecast 2011
1	Plant Entitlement Use (GWh) in previous year	1,608	1,585	1,533
2	Water Fees ($000s)	**8,656**	**9,250**	**9,381**

Table 2 – D – Wheeling

		Actual 2009	Forecast 2010	Forecast 2011
1	**Wheeling Nomination**		(MW per year)	
2	Okanagan	2,115	2,160	2,220
3	Creston	420	420	420
4	**Expense**		($000s)	
5	Vernon/Okanagan	3,500	3,536	3,663
6	Creston	453	448	451
7	Other	50	37	24
8	Duck Lake Wheeling Revenue			(800)
9	**Total Wheeling Expense**	**4,003**	**4,021**	**3,338**

Note: Minor differences due to rounding.

Table 2 – E – Operating and Maintenance Expense

		Approved 2010	Forecast 2011
1	O&M, Formula-Driven		
2	Base O&M Cost per Customer (Note-2)	$ 379.04	379.60
3	Consumer Price Index (British Columbia)	2.0%	2.3%
4	Productivity Improvement Factor	-1.5%	-1.5%
5	O&M per Customer, Escalated	380.93	382.64
6	Average Number of Customers (Line 17)	112,051	113,346
		($000s)	
7	Base O&M (Line 5 times Line 6)	42,684	43,370
8	Pension and Post-Retirement Benefits (Note 1)	3,749	4,686
9	Mandatory Reliability Compliance (MRC) (Note 1)	-	850
10	Trail Office Lease (Note 1)	1,212	1,212
11	Total Operating and Maintenance Expense for Base O&M	47,645	50,118
12	Capitalized Overhead	(9,529)	(10,024)
13	Net Operating & Maintenance Expense	38,116	40,094
14	Number of Customers		
15	Opening Count	111,190	112,355
16	Ending Count	112,911	114,336
17	Average Number of Customers	112,051	113,346

Note 1:

Under the terms of the 2006 NSA and Commission Order G-58-06, Pension and Post-Retirement Benefits and the Trail Office Lease costs are excluded from the formula in calculating Base O&M. The O&M costs for Mandatory Reliability Compliance has also been treated similarly starting 2011.

Note 2:

The Base O&M Cost per Customer for the purposes of calculating Revenue Requirements under PBR has been adjusted downward by $1.33/-Customer effective January 1, 2011 to $379.60 to rebase for the HST savings ($151,000 approx).

Note: Minor differences due to rounding.

Table 2 – F – Property Tax

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
1	Generating Plant	2,548	2,838	2,984
2	Transmission and Distribution	5,405	5,570	6,449
3	Substation Equipment	3,000	3,318	3,955
4	Land and Buildings	620	524	552
5	**Total Property Tax**	**11,573**	**12,250**	**13,940**

Note: Minor differences due to rounding.

Table 2 – G – Other Income

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
1	Apparatus and Facilities Rental			
2	Electric Apparatus Rental	2,755	3,848	2,744
3	Lease Revenue	169	140	138
4		2,924	3,988	2,882
5	Contract Revenue			
6	Waneta Management Fee	311	394	401
7	Waneta Management Fee Capital	2	20	8
8	Waneta Carrying Costs	94	94	94
9				
10	Brilliant Management Fee	174	208	253
11	Brilliant Management Fee Capital	289	270	310
12				
13	Fortis Pacific Holdings Inc.	530	634	433
14		1,400	1,621	1,499
15	Miscellaneous Revenue			
16	Connection Charges	482	491	509
17	NSF Cheque Charges	10	11	11
18	Sundry Revenue	183	170	379
19		675	672	899
20				
21	Investment Income	188	251	175
22				
23	**Total**	**5,187**	**6,532**	**5,455**

Note: Minor differences due to rounding.

Table 2 – H – 1 – 2010 Flow Through Adjustments

		Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
					($000s)			
1	2009 Incentive True Up	2,368	3,457	(1,089)	-	(1,089)	100%	**(1,089)**
2	Interest Expense	36,782	35,498	(1,284)	366	(918)	100%	(918)
3	Pope & Talbot (Payment from Customer)	-	-	(123)	35	(88)	100%	(88)
4	2009 Cost of Removal Tax Savings		-	(705)	-	(705)	100%	(705)
5	2010 Cost of Removal Tax Savings			(364)	-	(364)	100%	(364)
6	2010 HST Savings			(76)	22	(54)	100%	(54)
7	Flow Through Adjustment							**(2,129)**

Note: Minor differences due to rounding.

Table 2 – H – 2 – 2010 ROE Incentive Adjustment

		Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
				($000s)		
8	Net Income for ROE Incentive	38,614	37,718	896	50%	448
9	Common Equity	390,046	378,300			
10	Allowed ROE	9.90%	9.97%	0.07%	50%	0.04%

Note: Minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
1	UTILITY INCOME BEFORE TAX	72,659	78,764	89,813
2	Deduct:			
3	Interest Expense	33,411	35,498	40,548
4				
5	ACCOUNTING INCOME	39,248	43,266	49,265
6				
7	Deductions			
8	Capital Cost Allowance	50,764	52,072	57,533
9	Capitalized Overhead	9,315	9,529	10,024
10	Incentive & Revenue Deferrals	(2,014)	1,009	2,770
11	Financing Fees	910	615	619
12	All Other (net effect)	1,048	1,980	2,297
13		60,023	65,205	73,243
14				
15	Additions			
16	Amortization of Deferred Charges	2,521	3,703	3,297
17	Depreciation	34,855	38,085	42,201
18		37,376	41,788	45,498
19				
20	TAXABLE INCOME	16,601	19,849	21,521
21				
22	Tax Rate	30.0%	28.5%	26.5%
23				
24	Taxes Payable	4,980	5,657	5,703
25	Prior Years' Overprovisions/(Underprovisions)	(487)	(738)	-
26	Deferred Charges Tax Effect	256	181	195
27				
28	**REGULATORY TAX PROVISION**	**4,749**	**5,100**	**5,898**

Note: Minor differences due to rounding.

Table 3 – A – Calculation of Capital Cost Allowance

Line	Class	2010 Closing UCC	2011 Additions	Half-Year Rule	CCA Rate	2011 CCA	2011 Closing UCC
				($000s)			
1	1A	249,601	3,232	1,616	4%	10,049	242,784
2	1B	2,878	1,244	622	6%	210	3,912
3	17	99,918	31,759	15,879	8%	9,264	122,413
4	2	23,961	-	-	6%	1,438	22,523
5	3	1,401	-	-	5%	70	1,331
6	6	10	-	-	10%	1	9
7	8	4,852	1,518	759	20%	1,122	5,247
8	10	6,188	2,000	1,000	30%	2,156	6,032
9	12	776	2,697	1,348	100%	2,124	1,349
10	13	1,934	-	-	est	150	1,784
11	42	4,097	4,005	2,003	12%	732	7,370
12	45	609	-	-	45%	274	335
13	46	2,355	2,503	1,251	30%	1,082	3,776
14	47	311,918	83,004	41,502	8%	28,274	366,647
15	50	497	1,142	571	55%	587	1,052
16		**710,994**	**133,103**	**66,551**		**57,533**	**786,564**
17							
18							
19	Land		6,025				
20	Net Salvage		(4,495)				
21	AFUDC		3,016				
22	Capitalized overhead		10,024				
23	CIAC		10,581				
24	Plant in service		**158,254**				

Note: Minor differences due to rounding.

SCHEDULE 4 – COMMON SHARE EQUITY

			Actual 2009	Forecast 2010	Forecast 2011
				($000s)	
1	Share Capital		178,000	188,000	213,000
2	Retained Earnings		177,255	197,254	220,420
3					
4	COMMON EQUITY - OPENING BALANCE		355,255	385,254	433,420
5					
6	Less:	Common Dividends	(14,500)	(15,000)	(16,000)
7					
8	Add:	Net Income	34,499	38,166	43,367
9		Shares Issued	10,000	25,000	10,000
10					
11	COMMON EQUITY - CLOSING BALANCE		385,254	433,420	470,787
12					
13	SIMPLE AVERAGE		370,254	409,337	452,103
14					
15	Adjustment for Shares Issued		(3,726)	(12,432)	(3,685)
16	Deemed Equity Adjustment		-	(18,605)	(10,364)
17					
18	**COMMON EQUITY - AVERAGE**		**366,528**	**378,300**	**438,054**

Note: Minor differences due to rounding.

Table 4 – A – Calculation of Adjustment for Shares Issued

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
19	Opening Balance	178,000	188,000	213,000
20	Adjustment to Opening Balance			
21	Shares Issued #1	5,000	-	5,000
22	Issue Date	Sep 29		Sep 29
23				
24	Shares Issued #2	5,000	25,000	5,000
25	Issue Date	Dec 31	Dec 30	Dec 28
26				
27	Opening Balance x Days in Effect /365	178,000	188,000	213,000
28	Share Adjustment			
29	Issue #1 times Days in Effect / 365	1,274	-	1,274
30	Issue #2 times Days in Effect / 365	-	68	41
31		179,274	188,068	214,315
32	less: Simple Average	(183,000)	(200,500)	(218,000)
33	**Adjustment for Shares Issued**	**(3,726)**	**(12,432)**	**(3,685)**

Note: Minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

		Actual 2009	Forecast 2010	Forecast 2011
			($000s)	
1	Secured and Senior Unsecured Debt	527,002	553,863	650,000
2	Proportion	60.66%	58.56%	59.35%
3	Embedded Cost	6.33%	6.21%	6.04%
4	Cost Component	3.84%	3.63%	3.59%
5	Return	33,363	34,372	39,275
6				
7	Short Term Debt	(24,722)	13,587	7,081
8	Proportion	-2.85%	1.44%	0.65%
9	Embedded Cost	-0.19%	8.29%	17.98%
10	Cost Component	0.01%	0.12%	0.12%
11	Return (including fees)	48	1,126	1,273
12				
13				
14	Common Equity	366,528	378,300	438,054
15	Proportion	42.19%	40.00%	40.00%
16	Embedded Cost	9.41%	10.09%	9.90%
17	Cost Component	3.97%	4.04%	3.96%
18	Return	34,499	38,166	43,367
19				
20	TOTAL CAPITALIZATION	868,808	945,750	1,095,135
21	RATE BASE	867,683	945,750	1,095,135
22				
23	Earned Return	67,909	73,664	83,915
24				
25	RETURN ON CAPITAL	7.82%	7.79%	7.66%
26	RETURN ON RATE BASE	7.83%	7.79%	7.66%

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Our File: 30960/0001

December 6, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("FBC") 2010 Annual Review, 2011 Revenue Requirements and Negotiated Settlement Process, Project No. 3698570

We are counsel to the British Columbia Municipal Electrical Utilities ("BCMEU"). The BCMEU writes to generally confirm acceptance of the draft Negotiated Settlement Agreement attached to Mr. Bill Grant's letter of November 26, 2010 with the exception of the following comments on issues which arose in this process.

1. The BCMEU is very concerned with the dramatic increase in the "investigative projects" and the associated rate risks to ratepayers. The issue was set out in response to Celgar IR 1.8 in Table, Celgar A8.1. In 2008 FBC spent $125,000 on investigation projects. In 2011 FBC proposes to spend $3,285,000. This is a dramatic increase and the BCMEU wishes to confirm that these expenditures will be the subject of future prudency reviews. While it is the BCMEU's understanding these costs will be subject to prudency review and may be disallowed the BCMEU would assert at this time that the proposed expenditure of $700,000 in 2011 on investigation of a Single Cycle Gas Turbine is imprudent. We are advised a similar project has previously been considered and rejected for the region given air quality issues. This seems an inappropriate and imprudent expense for this electric utility and the ratepayers should not bear this cost or risk.

2. The BCMEU is concerned with the various costs associated with the dispute with Shaw including (a) the increased litigiousness of FBC and resultant costs to ratepayers; (b) the increased capital being spent by FortisBC on telecommunications infrastructure (which is the subject of the Capital Plan review) and (c) the impact on revenue requirements in 2011 and beyond resulting from changes in the revenue received from third party contacts revenue and the resultant increased O&M as FortisBC adds costs to manage infrastructure which may

have been best provided by a third party. Generally, the BCMEU is supportive of the concerns expressed by Shaw in its letters of comment and will continue to monitor this issue.

3. The BCMEU, and we understand FortisBC, are concerned with the cumulative impact of rate increases caused by the cumulative impact in 2011 of this Revenue Requirement Application; the implementation of rate rebalancing; and the expected BC Hydro rate increase in 2011 resulting in a 13 percent impact on certain customers in 2011. The BCMEU urges the Commission to consider phasing in the rate rebalancing to mitigate the impact on customers. Attached as Appendix A to this letter is a proposal filed today by the BCMEU with the Commission in response to the Commission's request for comment on implementation of the FortisBC COSA. The BCMEU's proposal would mitigate the rate shock the Residential and Wholesale Customer classes will face in 2011. This proposal is now before the Commission Panel which is considering the FortisBC COSA Decision and is provided here for information purposes only.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: BCMEU
cc: FortisBC Inc.
cc: Registered Intervenors

APPENDIX A

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Our File: 24265/0003

December 6, 2010

VIA ELECTRONIC MAIL

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

Attention: Erica M. Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: Fortis BC Inc. 2009 Rate Design Application and Cost of Service Study, Project No. 3698564 - COSA Re-filing Pursuant to Commission Order G-156-10: British Columbia Municipal Electrical Utilities Comments in Response to Commission Letter No. L-95-10

We are counsel to the British Columbia Municipal Electrical Utilities (the "BCMEU") and write in response to the Commission's letter dated November 30, 2010 regarding the above-noted matter.

On November 19, 2010 FortisBC ("FortisBC" or the "Company"), via a letter from Dennis Swanson, filed with the British Columbia Utilities Commission (the "Commission" or "BCUC") a rerun of the COSA (the "COSA Update") in compliance with the Board's directives on these issues specified in the Commission's Order G-156-10 (the "Decision"). The Company also set out a proposed five-year rebalancing program with assumed system-average increases, designed to bring rates to within the prescribed range of reasonableness. The resultant increases and revenue to cost ratios, as measured by the COSA Update, were summarized on Appendix A to Mr. Swanson's letter. In its letter, FortisBC indicated it expected customers may have comments on the filing.

On November 30, 2010, in Letter No. L-95-10, the Commission invited comments on the filing from participants in the Rate Design proceeding. Since closure of the record on the COSA proceeding, customer groups have become aware of significant rate impacts caused by revenue requirement processes and forecast BC Hydro rate increases which will impact FortisBC ratepayers likely resulting in cumulative rate increases in excess of 13% for wholesale customers, which primarily service residential customers, and the Residential Customer class of FortisBC. We understand FortisBC is as concerned about these cumulative rate impacts as are the impacted ratepayers. The more moderate approach to rate rebalancing proposed set out below, which is consistent with the Commission's Directives, will mitigate the "rate shock" Residential and Wholesale Customer classes will otherwise face in 2011.

The BCMEU wishes to advise the Commission that its consultant, Dr. Rosenberg, has reviewed the COSA Update and agrees that its methodology complies with the directives set forth in the Decision. Dr. Rosenberg has also reviewed the rebalancing proposal of the Company and notes that he could not find any formulae or algorithms that were used to derive the specific rebalancing increases. He did observe that there were rebalancing increases proposed in years for classes that were nevertheless within the band of reasonableness stipulated by the Decision. On its face this appears to contravene Directive # 19 of the Decision, which states as follows:

> The Commission Panel finds that the appropriate target for revenue-to-cost ratios in each class is unity or one, and that *future rebalancing should **only** be required when a customer class falls **outside** the range of reasonableness.* (Emphasis added)

The range of reasonableness was specified (by Directive #18) to be from 95 percent to 105 percent. Dr. Rosenberg also appreciates that it is unavoidable to apply rebalancing increases even to a class that is within the range of reasonableness because of the arithmetic requirement that the rebalancing movements sum to zero, i.e., that the rebalancing exercise in each year is revenue neutral to the Company. Notwithstanding that constraint, he notes that the Company proposal exacerbates that problem, and yields results that, on its face, seem unreasonable and unwarranted. For example, Nelson Wholesale is within the range of reasonableness. Nevertheless, under the Company proposal in Year 1, Nelson would experience the maximum possible increase of 10%, the same increase allotted to the Lighting Class which has the lowest R/C ratio. BCMEU submits that this is unfair and irrational on its face. Consequently, Dr. Rosenberg has devised an alternative five-year rebalancing plan that BCMEU would like to respectfully offer for the Commission's consideration.

The BCMEU's proposed five-year rebalancing of rates is in full conformance with the directives specified in the Commission's Order G-156-10, and the results therefrom, are attached to this letter. These tables provide the same information as, and are directly comparable to, Appendix A to FortisBC's letter of November 19. The BCMEU's rebalancing proposal used the following algorithms, listed in order of decreasing priority:

- The Irrigation class receives a system average increase in each year.
- No class receives a *rebalancing* increase in any one year greater than 5%.
- No class receives a *total* increase in any one year greater than 10% based upon the presumed system increases.
- All classes with an R/C ratio of below 0.95 (except the Irrigation class for which the Commission mandated an exemption) are targeted to an R/C ratio of 0.95 for the ensuing year.

- No class that is within the range of reasonableness is given a rebalancing increase except as required for the rebalancing increases and decreases to be revenue neutral.
- All classes with an R/C ratio of above 1.20 are targeted to an R/C ratio of 1.15 for the ensuing year.
- All classes with an R/C ratio of above 1.10 are targeted to an R/C ratio for the ensuing year of 50 basis points (5 percent) less than they displayed for the previous year.
- All classes with an R/C ratio of above 1.05 are targeted to an R/C ratio of 1.05 for the ensuing year.
- If any shortfalls must be recovered, they are recovered first from classes with an R/C ratio of less than unity (1.0) before they can be recovered from classes with an R/C ratio of greater than unity.

While both the Company's rebalancing proposal, as well as the BCMEU's proposal, bring all classes to within the range of reasonableness within the five-year horizon (and for most classes much faster than that), we submit that the BCMEU's proposed rebalancing is more fair and reasonable than the Company's proposed rebalancing proposal for the following reasons:

- BCMEU's rebalancing proposal follows a well-defined transparent algorithm as described above in this letter. If the Company's method follows such an algorithm it was not apparent from its packet of material or its letter of November 19.
- BCMEU's proposal avoids the anomaly noted previously, that pertains to the Company's proposed rebalancing. Thus, under the BCMEU's proposal only a single class would experience the maximum 10% increase, instead of four classes.
- BCMEU's proposal is more moderate with respect to those classes who receive above average increases. For example, under the Company proposal the class with the largest cumulative increase, the Lighting class, is slated for a compound increase of 45.3%, or over twice the system average compound increase of 22.6%. Under the BCMEU proposed alternative, the compound increase for that class is 39.4%, or less than 1.75 times the system average. The same commendation can be said for the other classes as well. Under the Company proposal the class with the second largest cumulative increase, the Residential class, is slated for a compound increase of 31.3% over the five-year horizon. Under the BCMEU proposed alternative, the compound increase for that class is held to a more moderate 29.3%.
- Under the Company proposal, the General Service class actually gets a decrease in rates, despite the double digit increase for the system as a whole. Under the BCMEU alternative, that class would not get a decrease.

Moreover, the BCMEU proposed alternative achieves these tempered and what we consider to be more logical results without sacrificing the Commission's objective of bringing revenue to cost

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ratios closer to unity and within the range of reasonableness. For example, even under the BCMEU proposal all classes are within the range of reasonableness (excluding the exempted Irrigation class) by Year 3 with the exception of the General Service Class, which is brought within the range in Year 4.

In closing, the BCMEU wishes to reiterate that it is fully supportive of the directives regarding rate rebalancing contained in the Commission's Decision and fully appreciates the philosophy and reasoning behind those directives. However, there is more than one way to implement that guidance. The BCMEU would also note that the revenue-to-cost ratios for Years 2 through 5 are predicated on the implicit assumption that the revenue requirements (i.e. the costs) for each year increase proportionally for each class. In reality, no party knows how future changes in FortisBC's cost structure will impact the relative cost responsibility for each class – even if usage patterns remain exactly as they were in 2009. Consequently, the BCMEU would urge the Commission to give temperance and moderation more weight in deciding which rebalancing plan to approve at this time. The BCMEU also urges the Commission to accept Dr. Rosenberg's recommendation to periodically revisit the revenue to cost relationships rather than carve these rebalancing increases in stone.

Thank you for your consideration of our submissions. In closing, we would reiterate that since closure of the record on the COSA proceeding, customer groups have become aware of significant rate impacts caused by revenue requirement processes and forecast BC Hydro rate increases which will impact FortisBC ratepayers. The more moderate approach to rate rebalancing proposed above, which is consistent with the Commission's Directives, will mitigate the "rate shock" residential and wholesale customers will otherwise face in 2011. This, we submit, is in the public interest.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
Enclosure
cc: BCMEU
cc: FortisBC Inc.
cc: Registered Intervenors

CPW20473

Appendix A

2009 COSA - Compliance Filing
BCMEU Proposed Version

Resulting Ratios with Forecast Increases

	Initial	Year 1	Year 2	Year 3	Year 4	Year 5
	Revenue to Cost Ratio	Revenue to Cost Ratio	Revenue to Cost Ratio	Revenue to Cost Ratio	Revenue to Cost Ratio	Revenue to Cost Ratio
Residential	93.3%	97.4%	97.4%	98.3%	98.5%	98.5%
Small General Service	107.6%	105.0%	105.0%	105.0%	105.0%	105.0%
General Service	128.2%	111.0%	111.0%	106.1%	105.0%	105.0%
Large GS Primary 30	112.8%	105.1%	105.1%	105.0%	105.0%	105.0%
Large GS Transmission 31	98.7%	100.3%	100.3%	100.3%	100.3%	100.3%
Lighting	84.4%	91.6%	91.6%	95.7%	95.9%	95.9%
Irrigation	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%
Wholesale Primary	94.0%	97.5%	97.5%	98.3%	98.5%	98.6%
Nelson Wholesale	95.1%	97.7%	97.7%	98.6%	98.8%	98.8%

Appendix A

2009 COSA - Compliance Filing
BCMEU Proposed Version

Resulting Total Rate Increase with Forecast Increases

	Year 1 Total Rate % Increase	Year 2 Total Rate % Increase	Year 3 Total Rate % Increase	Year 4 Total Rate % Increase	Year 5 Total Rate % Increase	Compound Increase
Residential	9.7%	5.3%	4.3%	3.7%	3.5%	29.4%
Small General Service	3.8%	4.1%	3.4%	3.5%	3.5%	19.6%
General Service	-4.1%	-0.1%	-1.1%	2.4%	3.5%	0.4%
Large GS Primary 30	1.8%	1.3%	3.3%	3.5%	3.5%	14.1%
Large GS Transmission 31	7.9%	4.2%	3.4%	3.5%	3.5%	24.5%
Lighting	10.0%	9.2%	8.1%	3.7%	3.5%	39.4%
Irrigation	6.2%	4.2%	3.4%	3.5%	3.5%	22.6%
Wholesale Primary	8.9%	5.3%	4.3%	3.7%	3.5%	28.5%
Nelson Wholesale	7.9%	5.3%	4.3%	3.7%	3.5%	27.3%
Assumed FortisBC Increase	6.2%	4.2%	3.4%	3.5%	3.5%	22.6%

Rebalancing Impact on Rates

	Year 1 Total Rate % Increase	Year 2 Total Rate % Increase	Year 3 Total Rate % Increase	Year 4 Total Rate % Increase	Year 5 Total Rate % Increase	Compound Increase
Residential	3.5%	1.1%	0.9%	0.2%	0.0%	5.8%
Small General Service	-2.4%	-0.1%	0.0%	0.0%	0.0%	-2.5%
General Service	-10.3%	-4.3%	-4.5%	-1.1%	0.0%	-19.0%
Large GS Primary 30	-4.4%	-2.9%	-0.1%	0.0%	0.0%	-7.3%
Large GS Transmission 31	1.7%	0.0%	0.0%	0.0%	0.0%	1.7%
Lighting	3.8%	5.0%	4.7%	0.2%	0.0%	14.4%
Irrigation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wholesale Primary	2.7%	1.1%	0.9%	0.2%	0.0%	5.1%
Nelson Wholesale	1.7%	1.1%	0.9%	0.2%	0.0%	4.0%

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December 3, 2010

BRITISH COLUMBIA UTILITIES COMMISSION
Sixth Floor, 900 Howe St. Box 250
Vancouver, B.C.
V6Z 2N3

Attention: Mr. William J. Grant, Consultant

Dear Mr. Grant:

Re: FortisBC Inc. ("FortisBC") Negotiated Settlement Agreement (NSA) 2011 Revenue Requirements Application

We write in response to your request of December 2, 2010 to provide confirmation of our acceptance of the NSA for FortisBC's 2011 Revenue Requirements Application.

Zellstoff Celgar hereby confirms acceptance of the NSA but also urges the Commission to pursue a prudency review for all capital projects, past, current and proposed, that have had a component of communications infrastructure that involved either the installation of fibre optic cable or the relocation of cable owned by Shaw. Zellstoff Celgar requests that it be copied on future correspondence from the Commission concerning applications associated with the foregoing topic, or any future FortisBC capital plan applications.

Yours truly,

ZELLSTOFF CELGAR LIMITED PARTNERSHIP
By its General Partner, Zellstoff Celgar Limited

Per:

Mr. Brian Merwin
Vice President, Strategic Initiatives

cc: Ms. Yolanda Domingo, BCUC

British Columbia
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Barristers & Solicitors

Jodie Gauthier
Articled Student

Via Email

December 1, 2010 Our file: 7467

Erica Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. 2010 Annual Review, 2011 Revenue Requirements and Negotiated Settlement Process ~ Project No. 3698570

We are solicitors for BC Old Age Pensioners' Organization, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre (collectively known as BCOAPO), and write to provide our comments on the draft Negotiated Settlement Agreement (NSA) in this proceeding.

BCOAPO supports the revisions to the draft NSA as proposed by Shaw on November 30 and Celgar on December 1, 2010. We have no further amendments to the NSA.

As noted during the negotiations, BCOAPO is concerned about FortisBC's rising electricity rates and the impact that these rates are having on residential ratepayers, and in particular on low and fixed income residential ratepayers. The cumulative rate impact of the 2011 Revenue Requirements rate increase, the rebalancing impact of the Commission's recent decision in FortisBC Rate Design and Cost of Service application, and a significant BC Hydro flow through rate increase for 2011 could result in a 13% rate increase for FortisBC residential ratepayers in 2011. A 13% rate increase in our view amounts to rate shock, and will cause low-income FortisBC customers a great deal of hardship.

In response to the Commission's request of November 30, 2010, we will be providing comments on the re-run COSA and the manner in which Order G-156-10 should be interpreted in order to mitigate these extreme rate impacts.

We would like to thank commission staff, FortisBC and the other parties for their efforts in reaching the NSA.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by

Sarah Khan
Barrister & Solicitor

c. Dennis Swanson, FortisBC Inc.
Registered Intervenors

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Barristers & Solicitors

Jodie Gauthier
Articled Student

Via Email

December 6, 2010 Our file: 7467

Erica Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. 2010 Annual Review, 2011 Revenue Requirements and Negotiated Settlement Process ~ Project No. 3698570

We are solicitors for BC Old Age Pensioners' Organization, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC, and Tenant Resource and Advisory Centre (collectively known as BCOAPO), and write to provide further comments on the draft Negotiated Settlement Agreement ("NSA") in this proceeding.

As noted in our letter of December 1, 2010 to the Commission, we are concerned that rate increases for residential customers will amount to rate shock. We are joining with the BC Municipal Electric Utilities ("BCMEU") to request that the Commission consider phasing in the rate rebalancing set out in Order Order G-156-10 in order to mitigate the impact on customers. In this regard, we are adopting the proposal provided to you earlier today in this proceeding by Chris Weafer, counsel to the BCMEU. The proposal was prepared in response to the Commission's request for comment on implementation of the FortisBC Cost of Service Analysis. It is our view that this proposal would serve to moderate the rate shock that residential and wholesale customers are facing in 2011.

Please let me know if you have any questions.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by

Sarah Khan
Barrister & Solicitor

c. Dennis Swanson, FortisBC Inc.
Registered Intervenors

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Reply Attention of:	David Bursey
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Direct Fax:	604.646.2563
E-mail:	DWB@bht.com
Our File:	08-2749
Date:	December 6, 2010

British Columbia Utilities Commission
6th Floor – 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Yolanda Domingo

Dear Sirs/Mesdames:

Re: Commission Order G-142-10
FortisBC Inc. 2010 Annual Review, 2011 Revenue Requirements and Negotiated Settlement Process – Shaw Cablesystems Limited and Shaw Business Solutions Inc. (collectively "Shaw") comments on the draft Negotiated Settlement Agreement ("NSA")

Further to the Commission Staff's letter dated December 2nd, Shaw submits the following comments on the draft NSA.

As we have explained previously, Shaw's interest in this proceeding is limited to the revenue requirement implications of FortisBC's decisions related to the attachment of Shaw's telecommunications cable to FortisBC transmission poles. Specifically, FortisBC's decision to try to remove Shaw's cable and then install FortisBC telecommunications cable in its place has several revenue requirement implications, including:

- the loss of revenue from Shaw pole attachments;
- the additional cost of installing and maintaining telecommunications plant to duplicate the plant that Shaw has in place; and
- operating cost and revenue associated with new telecommunications services that FortisBC may offer.

During the NSP discussion, Shaw noted its view that since a discussion of these issues is to be deferred pending the outcome of the court case between FortisBC and Shaw (scheduled for

Bull, Housser & Tupper LLP

January 2011) and the BCUC proceeding on the Shaw application[1], then the revenue requirement decisions should also be deferred pending those outcomes. Shaw understands that the issues related to the Fortis/Shaw dispute will be dealt with in the Shaw application proceeding.

We agree with the BCUC staff position that the costs associated with the FortisBC's decisions associated with the Shaw dispute would be subject to a prudency review following the outcome of that dispute in any event.

Shaw therefore will register these comments and take no further position on the NSA.

Yours truly,

Bull, Housser & Tupper LLP

David Bursey

David Bursey

DWB/2636184

CC. FortisBC and NSP participants

[1] Shaw Cablesystems Limited And Shaw Business Solutions Inc. Application for use of FortisBC Inc. Electricity Transmission Facilities ~ Project No. 3698585

Dec. 6, 2010

Alan Wait
Box 2663
Grand Forks, B.C.
V0H 1H0

British Columbia Utilities Commission
Sixth Floor, 900 Howe St., Box 250
Vancouver, B.C.
V6Z 2N3

Att: Bill Grant

Re: FortisBC Application for 2011 Revenue Requirements

Dear Sir:

I am generally in agreement with Draft Revenue Requirements proposal as presented, and further, I wish to express my support for the concerns of the BCMEU as per the submission of Chris Weafer of Dec. 6 in regards to the implementation of the rate rebalancing to keep maximum increases from becoming ridiculously high for certain ratepayer groups.

Respectfully Submitted,

Alan Wait

From: Norm Gabana [mailto:ngabana@gmail.com]
Sent: Wed 08/12/2010 8:46 AM
To: Domingo, Yolanda BCUC:EX
Subject: Re: FortisBC NSP

Thanks.

I sent in a comment attached to Al Waits reply Dec 1st

This is a copy from the email

Yalanda My comment would be the say as Alan

Thank you Norman Gabana

If you need more please reply Thank for all your help Norm

On Mon, Dec 6, 2010 at 10:41 PM, Domingo, Yolanda BCUC:EX <Yolanda.Domingo@bcuc.com> wrote:
Good day Mr. Gabana,

It appears that we have not receive your letter of comment on the FortisBC Negotiated Settlement Agreement. Please advise whether you accept or not accept the Agreement.

Thank you.

Yolanda Domingo, B.Comm, CMA
British Columbia Utilities Commission
6th floor - 900 Howe Street
Vancouver, BC, V6Z 2N3
Phone 604.660.4771
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FORTISBC

Dennis Swanson
Director, Regulatory Affairs

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December 6, 2010

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. Negotiated Settlement Agreement 2011 Revenue Requirements

FortisBC Inc. ("FortisBC" or the "Company") confirms its acceptance of the Negotiated Settlement Agreement concerning the 2011 Revenue Requirements (the "2011 NSA"), and thanks the Commission Staff and Registered Intervenors for their participation and assistance in reaching the 2011 NSA.

The Company notes that the British Columbia Municipal Electric Utilities ("BCMEU"), British Columbia Old Age Pensioners' Organization et al. ("BCOAPO") and Zellstoff Celgar Limited Partnership ("Celgar"), while accepting the 2011 NSA, have chosen to comment on the prudency of certain investigative expenditures, the Company's efforts protect the interests of itself and its customers through court process, and rates in general.

With respect to the subject of prudency reviews of expenditures related to investigative projects contained in the Company's 2011 Capital Expenditure Plan, FortisBC notes that all projects are eligible to undergo a prudency review at the discretion of the Commission. It is inappropriate to prejudge the prudency of an expenditure prior to seeing the justification for the project and the Company sees no reason to single out any proposed project that will be the subject of further regulatory process.

With respect to the comment that the "litigiousness" of the Company is a cause for concern, FortisBC expresses its intention to continue to pursue opportunities to protect the interests of its customers and further believes that it has a responsibility to do so.

The Company notes that during the negotiated settlement discussions and specifically as part of the BCMEU response, a concern about rising electricity rates and their impact on customers was expressed. FortisBC is concerned about rising electricity costs and submits that the PBR plan has served to mitigate rate increases to its customers while delivering solid non-financial performance benefits.

In addition, FortisBC understands that the BCMEU has provided comments referred to in its December 6, 2010 letter concerning the proposed rebalancing to take place as part of the FortisBC 2009 Cost of Service and Rate Design Application. The Company will be providing comment on this matter under separate cover as contemplated in Commission letter L-95-10.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs