SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-147-07

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

FortisBC Inc.
2007 Annual Review, 2008 Revenue Requirements and
Negotiated Settlement Process

BEFORE: L.A. O'Hara, Commissioner December 4, 2007

O R D E R

WHEREAS:

A. Commission Order No. G-58-06 approved for FortisBC Inc. ("FortisBC" or "Company") 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 1st for the following year; and

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; and

C. By Order No. G-117-07 dated September 21, 2007, the Commission established a Regulatory Timetable for the 2007 Annual Review and a 2008 Revenue Requirements Workshop on November 8, 2007 in Kelowna, BC, followed by an NSP on November 9, 2007; and

D. On October 1, 2007, FortisBC filed its Preliminary 2008 Revenue Requirements, which sought a 4.0 percent general rate increase effective January 1, 2008; and

E. On November 1, 2007, Fortis BC filed an update to the 2008 Revenue Requirements Application ("Update"), which incorporated financial results and forecasts as of September 30, 2007, including financial Performance Standards for the period October 1, 2006 to September 30, 2007, and sought a lower general rate increase of 3.4 percent, effective January 1, 2008; and

F. As a result of the 2007 Annual Review on November 8, 2007 and 2008 Revenue Requirements Settlement discussions on November 9, 2007, a Settlement Agreement was proposed and agreed to by FortisBC and some Intervenors, with the participation of Commission Staff. The proposed Settlement Agreement, which results in a general rate increase of 2.9 percent effective January 1, 2008, was circulated to the participants and registered Intervenors on November 23, 2007; and

G. The proposed Settlement Agreement includes a 4.9 basis point yield spread between 10 year and 30 year Canada bonds in forecasting FortisBC's 2008 allowed rate of return on common equity ("ROE") under the Commission's automatic adjustment mechanism. By Letter No. L-93-07, dated November 22, 2007, the Commission established the 2008 ROE for the low-risk benchmark utility of 8.62 percent that is based on an average yield spread of 4.9 basis points between 10 year and 30 Canada bonds. Accordingly, FortisBC confirmed that the ROE incorporated into the Settlement Agreement is in accordance with FortisBC's 2008 allowed ROE; and

H. Letters of support to the proposed Settlement Agreement were received from Buryl Goodman and Alan Wait. A wording modification to the proposed Settlement Agreement with regard to income tax was suggested by the British Columbia Old Age Pensioners' Organization et al. ("BCOAPO"). The modified Settlement Agreement ("the Modified Settlement Agreement") was agreed to by BCOAPO, the Interior Municipal Electrical Utilities and FortisBC; and

I. In its letter of comment dated November 22, 2007, Horizon Technologies Inc. ("Horizon") submits that it does not support the proposed Negotiated Settlement Agreement ("NSA") and raised concerns with respect to (1) FortisBC Cost of Service Study and Rate Design Application ("RDA"), (2) Demand Side Management ("DSM"), and (3) 2007 BC Energy Plan. Horizon requests more description to the scope of the Rate Design Application to support FortisBC's original budget of $600,000 and expresses concern that the revised $400,000 budget per the proposed Settlement Agreement may result in a smaller scope for the RDA. Horizon submits that the projected 2008 DSM savings level should be increased to 23.9 GWh or higher from 19.5 GWh set out in the proposed Settlement Agreement. Finally, Horizon requires that FortisBC will consider the 2007 BC Energy Plan in all its 2008 projects and applications; and

J. In response to Horizon's submission, on November 23, 2007, FortisBC first states that it understands Horizon to be a company based outside its service territory that sells energy efficiency related consulting services. FortisBC then submits that the letter by Horizon should not be given any weight when considering the approval of the NSA and comments as follows:

- The issues of scope, participation and recommendations relating to the FortisBC RDA should be addressed in a rate design proceeding and not the 2008 Revenue Requirements and NSA.
- FortisBC considers the planned DSM savings, which were also reviewed by the DSM Committee, are appropriate and does not support the recommendation set out in Horizon's letter.
- Negotiating a specific standard and scope of consideration of the Energy Plan for all future regulatory applications is inappropriate and would go beyond the scope of FortisBC's 2008 Revenue Requirements Application and the NSA; and

K. By the due date of November 29, 2007, no comments were received from any Registered Intervenors who had not participated in the Settlement negotiation; and

L. The Commission has reviewed the proposed Settlement Agreement, the modification as shown on page 24 of Appendix A, comments and submissions related thereto and considers that approval is warranted.

NOW THEREFORE the Commission orders as follows:

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

2. The Commission considers that changes submitted by Horizon with regard to the RDA and the BC Energy Plan are beyond the scope of this Revenue Requirements proceeding and are not approved.

3. 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 4th day of December 2007.

BY ORDER

Original signed by:

L.A. O'Hara
Commissioner

Attachment

WILLIAM J. GRANT
TRANSITION ADVISOR,
REGULATORY AFFAIRS & PLANNING
bill.grant@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 22219

VIA E-MAIL

November 23, 2007

Dear Participants and Registered Intervenors:

Re: FortisBC Inc. ("FortisBC")
Negotiated Settlement Agreement
2008 Revenue Requirements Application

Enclosed is the Negotiated Settlement Agreement for FortisBC's 2008 Revenue Requirements Application.

Letters of Comment from the Participants in the negotiated settlement process are enclosed with this settlement package which is now public and is being submitted to the Commission and all Intervenors.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations will be requested to provide to the Commission their comments on the settlement package by November 29, 2007. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

Philip Nakoneshny

for William J. Grant

Attachments
cc: Mr. David Bennett
Vice President Regulatory Affairs and General Counsel
FortisBC Inc.
regulatory@fortisbc.com

FortisBC Inc. 2008 Revenue Requirements
Negotiated Settlement Agreement

Introduction

FortisBC Inc. ("FortisBC" or the "Company") filed its Preliminary 2008 Revenue Requirements on October 1, 2007, in accordance with the terms of a Multi-Year Performance Based Regulation Plan ("PBR Plan") approved by way of British Columbia Utilities Commission (the "Commission") Order No. G-58-06.

The Application reflected a general rate increase of 4.0 percent effective January 1, 2008. Following the submission of Information Requests by the Commission and Registered Intervenors and filing of responses, the Company filed an update to the 2008 Revenue Requirements Application on November 1, 2007 (the "Update"), incorporating financial results and forecasts as of September 30, 2007, and final Performance Standards for the period October 1, 2006 to September 30, 2007. The Update reflected a general rate increase of 3.4 percent, effective January 1, 2008, subject to the determination of 2008 Return on Equity arising from the Automatic Adjustment Mechanism and the outcome of a Negotiated Settlement Process ("NSP").

The 2007 Annual Review and 2008 Revenue Requirements Workshop was held in Kelowna, BC on November 8, 2007. FortisBC and a group of Intervenors participated in a NSP on November 9, 2007, and reached a Settlement Agreement, which is described in this document. The Settlement Agreement results in a general rate increase of 2.9% effective January 1, 2008. Summary Revenue Requirements Schedules, which also reflect the final 2008 Return on Equity are attached as Appendix A.

The following Parties participated in the NSP:

Participant	**Party**
W.J. Grant	British Columbia Utilities Commission
P. Nakoneshny	British Columbia Utilities Commission
D. Chong	British Columbia Utilities Commission
D. Flintoff	British Columbia Utilities Commission
J. Yang	British Columbia Utilities Commission
T. Andreychuk	The Interior Municipal Electricity Utilities, The City of Penticton
V. Kumar	The Interior Municipal Electricity Utilities, The City of Grand Forks
R. Leslie	The Interior Municipal Electricity Utilities, Nelson Hydro
C. McNeely	The Interior Municipal Electricity Utilities, The City of Kelowna
K. Ostraat	The Interior Municipal Electricity Utilities, The District of Summerland

S. Khan	The British Columbia Old Age Pensioners Organization et al.
B. Goodman and E. Goodman	FortisBC Ratepayers
A. Wait	FortisBC Ratepayer
L. Bertsch	Horizon Technologies
D. Bennett	FortisBC Inc.
J. Martin	FortisBC Inc.
M. Mulcahy	FortisBC Inc.
D. Swanson	FortisBC Inc.

Settlement Agreement

The Parties accept the 2008 Revenue Requirements Application, including the Update, as filed, subject to the following:

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FortisBC Inc.
2007 Annual Review and 2008 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 3 – Revenue Requirements			
Water Fees: (Sec. 3.4.2) Cost Classification	Water fees have been presented as a tax since 2005.	Water fee will be classified as part of power supply costs.	Exhibit B-2, Q10.1
Income Tax: (Sec. 3.4.3) Expected Reduction in Federal Corporate Income Tax Rate in 2008	On October 30, 2007 the Canadian government announced a further 1.0% reduction in the corporate income tax rate, effective January 1, 2008. If enacted, the federal rate will be reduced to 19.5% from 20.5% for 2008.	The expected federal corporate income tax reduction will be included in 2008 revenue requirements. If it is not enacted, the difference is subject to Z-factor treatment.	Updated Exhibit B-1, Tab 3, p. 16
Cost of Equity: (Sec. 3.5.2)	FortisBC was predicting an inverse yield curve for calculation of Benchmark ROE. Actual yield spread between 10 and 30 year bonds in October 2007 was 4.9 basis points, which will be used for setting the 2008 ROE benchmark rate.	Will be set through automatic adjustment mechanism. For current estimates, use a 4.9 basis point spread between 10 and 30 year government bonds.	Updated Exhibit B-1, Tab 3, p. 17; Exhibit B-2, BCUC IR Q20.1,
Deferred Charges: (Sec. 3.8.2) Deferred tax rate for 2007	Income tax impact for deferred charges should be 34.12% in 2007, rather than 33% as shown in Table 3.8.2.	FortisBC will adjust the 2007 income tax rate applicable to deferred charges to 34.12%.	Exhibit B-2, BCUC Q11.3.2; BCOAPO Q3.1
FortisBC Cost of Service and Rate Design Application (2008) (Sec. 3.8.2)	FortisBC forecast $600,000, before tax, for its Cost of Service Analysis and Rate Design Application.	For budget purposes, the forecast will be reduced to $400,000, before tax.	Updated Exhibit B-1, Tab 3, p. 30

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Revenue Protection: (Sec. 3.8.2)	Further detailed activity of the Revenue Protection cost of $260,000 in 2008 would be desirable.	Budget accepted. FortisBC will continue to provide detail on the Revenue Protection program annually, in accordance with Order G-58-06.	Updated Exhibit B-1, Tab 3, pp. 33-35; Exhibit B-2, BCUC Q15.4
Hydro Electric Supply Study – Recovery as a deferred charge (Sec. 3.8.2)	In the February 14, 2006 Update, FortisBC described this project as “Small Hydro Reconnaissance Study” and “recorded as a preliminary investigation, pending determination of feasibility”. FortisBC proposes to amortize the costs during 2008.	This cost will be expensed as per the Uniform System of Accounts as it does not lead to a capital project that is placed in service. The $21,000 of study costs will be expensed in 2007.	Updated Exhibit B-1, Tab 4, p. 32; Exhibit B-2, BCUC Q15.7
Related-Party Transactions		Disclosure of related party transaction will be a standard item for future revenue requirements applications.	Exhibit B-2, BCUC Q65.3
Contingent Liabilities: (Sec. 3.10) Forest Fire near Vaseux Lake and pending claims	FortisBC proposes to submit an application in regard to costs of litigation not covered under the Company’s insurance coverage, if necessary.	FortisBC will apply for cost recovery if they occur.	Updated Exhibit B-1, p. 39; Exhibit B-2, BCUC Q19.1, p.52
Tab 5 – Load and Customer Forecast			
Residential and General Service Forecast		Accept the Residential and General Service forecasts.	Updated Exhibit B-1 Tab 5, pp. 5-6; Exhibit B-2 BCUC Q29.0 to Q32.0
Wholesale Load Forecast	FortisBC’s 2008 Wholesale Load forecast (Tab 5, Appendix A) is 891 GWh.	Adjust Wholesale Load forecast for 2008 upwards to 904 GWh.	Exhibit B-1, Tab 5, pp. 12 and 17; B-2, BCUC Q34.2 and 34.3

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Subsequent Events: (Sec. 3.9) Industrial Load Forecast Uncertainty: CANPAR, Pope & Talbot, and Weyerhaeuser	FortisBC filed in confidence its forecast of 2008 load, revenue and power purchases resulting from closures and/or reduced operations of three of its largest industrial customers.	1. A deferral account will be established to capture the incremental costs and incremental revenue for load variance from the 2008 Forecast for CANPAR, Pope & Talbot, and Weyerhaeuser, which will flow through to rates in 2009. 2. The Company will use forecasts per the November 7, 2007 confidential filing with reduced load expectations, power purchases and revenue in 2008. 3. The net loss due to default of payments in 2008 is also recorded in the new deferral account.	Exhibit B-1, Tab 3, pp. 33-35; Exhibit B-2, BCUC Q16.0, Q17.0; Exhibit B-1-2, Tab 3, pp. 38-39
System Loss: (Sec. 5.3)	FortisBC incorporated a gross system loss factor of 9.4% in the 2007 updated and 2008 load forecasts. The four-year average is 9.4% and the three-year average is 8.8%.	A system loss factor of 9.1% will be used for the 2008 load forecast, based on the average of the four-year and three-year system losses meant to reflect the newer systems resulting in a declining trend of system loss. This is a negotiated position between the Parties.	Exhibit B-1, Tab 5, p. 13
Power Factor Surcharges for large distribution and transmission customers.	FortisBC's Tariff requires customers to maintain a power factor of not less than 90 percent lagging. The benefits of a higher power factor may include: • Lower line losses (currently 9.4%); • Reduction in peak demand and energy requirements; and • Reduction of power purchase expense	During 2008 FortisBC is to investigate a power factor penalty (Power Factor<0.95) in accordance with BC Hydro Electric Tariff Supplement No. 5	Exhibit B-2, BCUC Q4.1, pp. 6-7, Q4.2, p. 7, Q4.3, pp.7-8, Q35.1 - Q35.2, pp. 113-115, Q42.1, pp.124-125

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 7 – Capital Expenditures			
Preliminary Investigative Projects: (Sec. 7.2.8) Duck Lake Substation Property	FortisBC proposes to purchase property adjacent to its Duck Lake Substation in order to secure access and provide for possible future expansion of the substation.	The purchase of the land is not approved at this time. FortisBC may bring forward this item at a future time when a near term or medium term need is established.	Updated Exhibit B-1, Tab 7, p. 17; and attached report; Exhibit B-2, BCUC Q7.2 & Q51.3
Preliminary Investigative Projects: (Sec. 7.2.8) Pine Beetle Kill – Hazard Trees	FortisBC proposes to capitalize the removal of danger trees killed by the pine beetle as additional right of way reclamation expenditures.	Accept budget forecast for 2008 for the purposes of this negotiation. FortisBC is to provide detailed analysis at the next annual review of the extent of the hazard and the future costs. FortisBC and the Participants hold differing views on the treatment of removal costs for Pine Beetle Kill. The Parties agree that the 2008 removal costs will be recorded in a rate-base deferral account, amortized over 10 years, without prejudice to the treatment of future expenditures.	Updated Exhibit B-1, Tab 7, pp. 17-18; and attached report; Exhibit B-2, BCUC Q7.4, p.14; Q27.5.1, p.91, Q27.5.2, p.91, Q27.5.3, p.92, Q41.1, p.123; Exhibit B-2, Appendix Q28.1A, p.31
Preliminary Investigative Projects: (Sec. 7.2.8) Conductor Replacement (Burn-Off)	As the issue of dissimilar metals causing high contact resistance between copper and aluminum is well known, FortisBC is to propose corrective action to address this issue. FortisBC is to identify the estimated cost of replacing the hot line tap after a failure.	Will be addressed in a CPCN application.	Updated Exhibit B-1, Tab 7, p.17; Exhibit B-2, Q56.2, p. 160

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Demand Side Management: (Sec. 7.2.7)	Most DSM materials were filed after the November 1 Update so IRs on DSM were limited. The DSM material should come in with the other materials.	FortisBC commits to filing DSM results for previous year and previous six months before or with the Annual Review materials, including the incentive calculations and the other reports discussed at page 15 of (updated) Tab 7.	Updated Exhibit B-1, Tab 7, p.15; Exhibit B-2 BCUC Q55.1; Other DSM material filed on October 11; IRs sent out on Oct 12.
Capital Expenditure Operating Savings Report		Accepted as filed	Updated Exhibit B-1, Tab 7 Appendix 1
Tab 8 – 2007 Performance Standards			
Injury Severity Rate ("ISR") Target	The 2007 Injury Severity Rate Target was not met. If calculated using the three-year rolling average, the 2008 Target would be 21.62.	The Parties agree to retain the 2007 target of 17.53 for Injury Severity Rate in 2008. The Company will provide as part of the 2008 Annual Review/2009 Revenue Requirements a substantive report outlining the Company's safety program including its efforts to manage the injury severity rate.	Exhibit B-1-3, Errata, Tab 8 p.4A; Exhibit B-2, BCUC Q61.0 to Q61.1 p.166; Q61.3 p. 167, Q62.1.1 to Q62.1.2 pp. 167-168, Q61.3 p. 167, Q62.2 p. 168, Appendix A62.1.1; Appendix A62.2.
2007 Incentive Sharing		The Parties accept that FortisBC has generally met its performance targets in 2007 and has met the test set out in the NSA and is therefore eligible for its share of the financial incentive.	

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
BC Energy Plan		FortisBC will continue to consider the BC Energy Plan in its 2008 projects and applications. For example, the BC Energy Plan is a relevant factor in the rate design studies and application, the development of DSM programs, and future energy supply plans.	

Appendix A

2008 Revenue Requirements
Negotiated Settlement Agreement

Financial Schedules

FortisBC Inc.

REVENUE REQUIREMENTS OVERVIEW

		2008 Revenue Requirements		
		November 1 Update	Increase or (Decrease)	Settlement Agreement
			($000s)	
1	Sales Volume (GW.h)	3,166	(79)	3,087
2	Rate Base	823,434	(587)	822,847
3	Return on Rate Base	7.54%		7.47%
4				
5	**REVENUE DEFICIENCY**			
6				
7	**POWER SUPPLY**			
8	Power Purchases	70,840	(3,437)	67,403
9	Water Fees	7,858	-	7,858
10		78,698	(3,437)	75,261
11	**OPERATING**			
12	O&M Expense	45,310	-	45,310
13	Capitalized Overhead	(9,062)	-	(9,062)
14	Wheeling	3,622	-	3,622
15	Other Income	(5,030)	-	(5,030)
16		34,840	-	34,840
17	**TAXES**			
18	Property Taxes	11,176	-	11,176
19	Income Taxes	4,403	(414)	3,989
20		15,579	(414)	15,165
21	**FINANCING**			
22	Cost of Debt	31,784	(22)	31,762
23	Cost of Equity	30,269	(581)	29,688
24	Depreciation and Amortization	34,373	(17)	34,356
25	AFUDC	-	-	-
26		96,426	(620)	95,806
27				
28	Prior Year Incentive True Up	22	-	22
29	Flow Through Adjustments	(42)	-	(42)
30	AFUDC / CWIP shortfall	895	-	895
31	ROE Sharing Incentives	(2,159)	-	(2,159)
32		(1,284)	-	(1,284)
33				
34	**TOTAL REVENUE REQUIREMENT**	224,259	(4,471)	219,788
37				
39	Interest on Non Rate Base Deferral Account	27	-	27
40	ADJUSTED REVENUE REQUIREMENT	224,286	(4,471)	219,815
41	**Less: REVENUE AT APPROVED RATES**	216,829	(3,135)	213,694
42	**REVENUE DEFICIENCY for Rate Setting**	7,457	(1,336)	6,121
43				
44	**RATE INCREASE**	**3.4%**		**2.9%**

SCHEDULE 1 – UTILITY RATE BASE

	Actual 2006	Forecast 2007	Forecast 2008
	(Note 2)	($000s)	
Plant in Service, January 1	820,437	943,920	1,075,766
Net Additions	123,483	131,846	108,640
Plant in Service, December 31	943,920	1,075,766	1,184,406
Construction Work in Progress	33,208	47,897	66,300
Less: CWIP subject to AFUDC (Note 1)		(41,090)	(59,513)
Plant Held for Future Use	-	-	-
Plant Acquisition Adjustment	11,912	11,912	11,912
Deferred and Preliminary Charges	18,563	13,921	16,062
Less non-rate base deferral accounts		(895)	
	1,007,603	1,107,511	1,219,167
Less:			
Accumulated Depreciation			
and Amortization	226,508	249,139	275,031
Contributions in Aid of Construction	68,188	75,950	80,694
	294,696	325,089	355,725
Depreciated Rate Base	712,907	782,422	863,441
Prior Year Depreciated Utility Rate Base	631,231	712,907	782,422
Mean Depreciated Utility Rate Base	672,069	747,664	822,932
Allowance for Working Capital	7,511	7,269	7,188
Adjustment for Capital Additions	(4,806)	(10,818)	(7,273)
Mid-Year Utility Rate Base	674,773	744,115	822,847

Note 1. In 2007, the BCUC issued Commission Order No. G-20-07 which instructed FortisBC to remove Construction Work in Progress subject to AFUDC from rate base and to remove AFUDC from Revenue Requirements effective January 1, 2007.

Note 2. 2006 Closing balance of rate base items has been restated to include the effects of the rate base previously held by PLP.

Table I – A – Utility Plant in Service (2008)

Line	Account		December 31 2007	Additions	Retirements	December 31 2008
		Hydraulic Production Plant		(000s)		
1	330	Land Rights	120	-	-	120
2	331	Structures and Improvements	11,412	666	(84)	11,994
3	332	Reservoirs, Dams & Waterways	20,436	1,541	(80)	21,897
4	333	Water Wheels, Turbines and Gen.	59,908	274	(73)	60,110
5	334	Accessory Equipment	22,283	274		22,557
6	335	Other Power Plant Equipment	38,132	274		38,407
7	336	Roads, Railroads and Bridges	1,053		-	1,053
8			153,344	3,030	(237)	156,138
9		Transmission Plant				
10	350	Land Rights	7,079	-	-	7,079
11	350.1	Land Rights - Clearing	4,364			4,364
12	353	Station Equipment	160,319	35,637	(1,779)	194,177
13	355	Poles Towers & Fixtures	65,109	13,956	(966)	78,100
14	356	Conductors and Devices	64,993	13,956	(1,183)	77,767
15	359	Roads and Trails	817	-	-	817
16			302,682	63,549	(3,928)	362,303
17		Distribution Plant				
18	360	Land Rights	1,449	-	-	1,449
19	360.1	Land Rights - Clearing	4,153			4,153
20	362	Station Equipment	106,113	2,191	-	108,305
21	364	Poles Towers & Fixtures	105,121	7,495	(80)	112,536
22	365	Conductors and Devices	175,091	12,646	(80)	187,657
23	368	Line Transformers	78,344	5,398		83,743
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,225	615	-	13,840
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	5,691	-	-	5,691
28			497,418	28,346	(160)	525,603
29		General Plant				
30	389	Land	4,642	3,764	-	8,406
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	22,971	1,312	-	24,283
33	391	Office Furniture & Equipment	5,224	187	-	5,411
34	391.1	Computer Equipment	45,054	6,411	-	51,465
35	392	Transportation Equipment	18,449	2,461	-	20,910
36	394	Tools and Work Equipment	9,876	650	-	10,526
37	397	Communication Structures and Equipment	15,769	3,687	(432)	19,024
38			122,322	18,472	(432)	140,361
39						
40	101	Plant in Service	1,075,766	113,397	(4,757)	1,184,406
41	107.1	Plant under construction not subject				
42		to AFUDC	6,807			6,787
43	107.2	Plant under construction				
44		subject to AFUDC	41,090			59,513
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,135,575			1,262,618

Table I – A – 1 – Additions to Plant in Service (2008)

		CWIP Dec. 31, 2007	Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
			($000s)		
Hydraulic Production					
1	P1 Generator & Plant Cooling System Upgrade	22	370		392
2	P1U3 Upgrade & Life Extension	-	-		-
3	P2 Old Unit Repower	-	2,266	2,266	-
4	P3U1 Upgrade & Life Extension	3,258	4,062	7,320	-
5	P3U1 Headgate Rebuild	-	54	54	-
6	P3U3 Upgrade & Life Extension	3,500	6,460	9,960	-
7	P3U3 Headgate Rebuild	327	270	-	597
8	P3 Plant Completion	545	616	1,161	-
9	P3 H/G Hoist, Control, Wire Rope Upg		669		669
10	P4U1 Upgrade & Life Extension	533	382	915	-
11	P1 Misc Upgrades	-	290	-	290
12	P2 Misc Upgrades		290	-	290
13	P3 Misc Upgrades	-	338	-	338
14	P4 Misc Upgrades	-	454	-	454
15		8,185	16,521	21,675	3,030
Transmission Plant					
16	Okanagan Transmission Reinforcement	4,235	13,978	18,213	-
17	Big White 138 KV Line & Substation	4,474	7,295	-	11,769
18	Ellison Distribution Source	2,103	11,937	-	14,040
19	Naramata Rehabilitation	2,647	2,458	5,105	-
20	Black Mountain Distribution Source	1,249	8,459	9,708	-
21	Hollywood/Mission Cap Increase	-	4,812	4,812	-
22	Kettle Valley	13,737	5,570		19,307
23	Transmission Line Sustaining	-	5,588	-	5,588
24	Station Sustaining	-	4,709	-	4,709
25	Castlegar Sub Cap	2,250	5,340		7,590
26	Crawford Bay Cap Inc	-	10		10
27	Capitalized Inventory & Transformers	6,787		6,787	-
28	Coffee Creek Capacitor 69Kv	-	-		-
29	Kaslo Capacitor 25Kv	-	-		-
30	18 L Breaker @ Waneta	-	1,800		1,800
31		37,482	71,956	44,625	64,813
Distribution Plant					
32	Customer New Connects	-	15,954		15,954
33	Distribution Sustaining	-	11,265		11,265
34	Mckinley Lnd Cap Upgrade	9	350		359
35	HOL1-OKM1 Tie-KLO Rd	10	339		349
36	SEX4 Regulator	10	150		160
37	Duck Lake Substation	-	-		-
38	Lee2-Hol5 Tie Add N.O	10	409		419
39	GLE2 Spall/Springfield UG	-	50		50
40	PRI04 Capacity Upgrade	84	798		882
41	OKF03 Capacity Upgrade	84	291		375
42	VAL01 Capacity Upgrade	10	887		897
43		217	30,493	-	30,710
General Plant					
44	Communications and Automation	119	1,902		2,021
45	Protection and Communications Rehabilitation	-	1,491		1,491
46	Vehicles	-	2,461		2,461
47	Metering	-	136		136
48	Information Systems	1,894	4,517		6,411
49	Telecommunications	-	175		175
50	Buildings	-	1,312		1,312
51	Furniture & Fixtures	-	187		187
52	Tools & Equipment	-	650		650
53		2,013	12,831	-	14,844
54	TOTAL	47,897	131,800	66,300	113,397

Table 1 – B – Deferred Charges and Credits (2007)

		Balance at Dec. 31, 2006	Additions and Transfers	Amortized to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2007
	Demand Side Management					
1	Demand Side Management Additions	17,882	2,473		(1,227)	19,128
2	Tax Impact	(12,064)	(844)			(12,908)
3	PLP Energy Management	190			(77)	113
4		6,008	1,629	-	(1,304)	6,333
5	**Deferred Regulatory Expense**					
6	Deferred Revenue - Incentive Adjustment	(2,524)	(1,306)	2,524		(1,306)
7	Provision for True-up for 2006 Incentive	34		(12)		22
8	2005 Revenue Requirements	529			(176)	353
9	Tax Impact	(152)	-		51	(101)
10	2006 Revenue Requirements	160			(53)	107
11	Tax Impact	(53)	-		18	(35)
12	2007 Revenue Requirements	29	7		-	36
13	Tax Impact	(9)	(2)		-	(11)
14	2007 BC Hydro Rate Design	-	17		-	17
15	Tax Impact	-	(6)		-	(6)
16	2008 Revenue Requirements	-	30		-	30
17	Tax Impact	-	(10)		-	(10)
18	Terasen Gas ROE Application	(3)			3	-
19	Tax Impact	6			(6)	-
20		(1,983)	(1,270)	2,512	(164)	(905)
21						
22	**Preliminary and Investigative Charges**	1,814	141	(1,874)	-	81
23						
24	**Other Deferred Charges and Credits**					
25	Trail Office Lease Costs	203			(12)	191
26	Trail Office Rental to SD#20	(564)		(34)	-	(598)
27	Prepaid Pension Costs	5,732	535		-	6,267
28	Tax Impact	(164)	(183)			(347)
29	Post Retirement Benefits	(1,329)	(2,230)			(3,559)
30	Tax Impact	441	761			1,202
31	Renegotiation of Canal Plant Agreement	412			(412)	-
32	Tax Impact	(59)	-		59	-
33	2005 System Development Plan	494			(165)	330
34	Tax Impact	(25)	-		9	(16)
35	2008 System Development Plan Update	-	250			250
36	Tax Impact	-	(85)			(85)
37	Automated Meter Reading Feasibility Study	-	100			100
38	Tax Impact	-	(34)			(34)
39	2005 Resource Plan	91	11		(30)	72
40	Tax Impact	(10)	(4)		3	(11)
41	2008 Resource Plan Update	-	350			350
42	Tax Impact	-	(119)			(119)
43	Hydro Electric Supply Study	21	(21)			-
44	Tax Impact	(7)	7			-
45	Renew BCH Power Purchase Agreement	3	-			3
46	Tax Impact	(1)	-			(1)
47	Discount Forfeit Defense (note 1)					-
48	Tax Impact (note 1)					-
49	Revenue Protection	590	165		(590)	165
50	Tax Impact	(194)	(56)		194	(56)
51	Big White Supply Project	3,342	(3,342)		-	-
52	Tax Impact	-	-		-	-
53	Innovative Clean Energy Fund Levy Implementation	-	25			25
54	Tax Impact		(9)			(9)
55	PLP Transition costs	74		(74)		-
56	Tax Impact	(24)		24		-
57	PLP Potential Substation	36			(11)	25
58	PLP Settlement Costs	63			(16)	47
59	PLP Computer Software	132			(23)	109
60	PLP Deferred Pension Credit	(93)			12	(81)
61	PLP Deferred Rate Stabilization Account	(75)			-	(75)
62	Other Deferred Charges and Credits	-	-		-	-
63		9,089	(3,879)	(84)	(982)	4,145
64	**Deferred Debt Issue Costs**					
65	Series E	10			(3)	7
66	Series F	142			(13)	129
67	Series G	127			(9)	118
68	Series H	121			(14)	107
69	Series I	213			(13)	200
70	Series J	196			(65)	131
71	Series 04-1	1,717			(215)	1,502
72	Tax Impact	(36)	(20)		4	(52)
73	Series 05-1	1,199			(42)	1,157
74	Tax Impact	(166)	(84)		6	(244)
75	Series 07-1	-	1,300		-	1,300
76	Tax Impact	-	(89)		-	(89)
77		3,524	1,107	-	(363)	4,267
78						
79	TOTAL DEFERRED CHARGES	18,453	(2,272)	554	(2,813)	13,921

80 Note 1:
81 Per the 2007 NSA regarding the Discount Forfeit defence costs, the 2007 opening Deferred Charges balance has been reduced by the of $110K
82 ($164K before tax); 2007 Additions and Transfers were reduced by $28k ($42K before tax) and 2007 closing Deferred Charges balance was
83 reduced by $138k ($206K before tax); and Interest of $10k on the average balance was included in 2007 rates.

APPENDIX A
to Order No. G-147-07
Page 16 of 40

Table 1 – B – Deferred Charges and Credits (2008)

		Balance at Dec. 31, 2007	Additions and Transfers	Amortized to Other Accounts ($000s)	Amortization	Balance at Dec. 31, 2008
	Demand Side Management					
1	Demand Side Management Additions	19,128	2,355		(2,055)	19,428
2	Tax Impact	(12,908)	(742)		668	(12,982)
3	PLP Energy Management	113			(77)	36
4		6,333	1,613	-	(1,464)	6,482
5	**Deferred Regulatory Expense**					
6	Provision for True-up for 2006 Incentive	22		(22)		-
7	Deferred Revenue - Incentive Adjustment	(1,306)		1,306		-
8	2005 Revenue Requirements	353			(176)	177
9	Tax Impact	(101)			51	(50)
10	2006 Revenue Requirements	107			(53)	53
11	Tax Impact	(35)			18	(18)
12	2007 Revenue Requirements	36			(36)	-
13	Tax Impact	(11)			11	-
14	2008 Revenue Requirements	30			-	30
15	Tax Impact	(10)			-	(10)
16	2008 Cost of Service and Rate Design	-	400			400
17	Tax Impact	-	(126)			(126)
18	2009 Revenue Requirements	-	50		-	50
19	Tax Impact	-	(16)		-	(16)
20	2007 BC Hydro Rate Design	17			(17)	-
21	Tax Impact	(6)			6	-
22		(905)	308	1,284	(197)	491
23						
24	**Preliminary and Investigative Charges**	81	310	(60)	-	331
25						
26	**Other Deferred Charges and Credits**					
27	Trail Office Lease Costs	191			(12)	179
28	Trail Office Rental to SD#20	(598)		(39)	-	(637)
29	Prepaid Pension Costs	6,267	1,155		-	7,422
30	Tax Impact	(347)	(364)			(711)
31	Post Retirement Benefits	(3,559)	(2,230)			(5,789)
32	Tax Impact	1,202	702			1,904
33	2005 System Development Plan	330			(165)	165
34	Tax Impact	(16)			9	(7)
35	2008 System Development Plan Update	250	125			375
36	Tax Impact	(85)	(39)			(124)
37	Automated Meter Reading Feasibility Study	100	(100)			-
38	Tax Impact	(34)	32			(2)
39	2005 Resource Plan	72			(30)	42
40	Tax Impact	(11)			3	(8)
41	2008 Resource Plan Update	350			(88)	263
42	Tax Impact	(119)			30	(89)
43	Hydro Electric Supply Study	-			-	-
44	Tax Impact	-			-	-
45	Renew BCH Power Purchase Agreement	3	197		-	200
46	Tax Impact	(1)	(62)		1	(62)
47	Discount Forfeit Defense (note 1)	206			(206)	-
48	Tax Impact (note 1)	(68)			68	-
49	Revenue Protection	165	260		(165)	260
50	Tax Impact	(56)	(82)		56	(82)
51	Big White Supply Project	-	-	-		-
52	Tax Impact	-	-	-		-
53	Innovative Clean Energy Fund Levy Implementation	25			(25)	-
54	Tax Impact	(9)			9	-
55	PLP Potential Substation	25			(11)	14
56	PLP Settlement Costs	47			(16)	31
57	PLP Computer Software	109			(23)	86
58	PLP Deferred Pension Credit	(81)			12	(69)
59	PLP Deferred Rate Stabilization Account	(75)			75	-
60	ROW Reclamation (Pine Beetle Kill)	-	2,500		-	2,500
61	Tax Impact	-	(788)		-	(788)
62	Industrial Load Forecast Variance	-	-		-	-
63	Tax Impact	-	-		-	-
64	Other Deferred Charges and Credits	-	-		-	-
65		4,283	1,306	(39)	(478)	5,072
66	**Deferred Debt Issue Costs**					
67	Series E	7			(3)	4
68	Series F	129			(13)	116
69	Series G	118			(9)	110
70	Series H	107			(14)	93
71	Series I	200			(13)	187
72	Series J	131			(65)	66
73	Series 04-1	1,502			(215)	1,288
74	Tax Impact	(52)	(20)		7	(65)
75	Series 05-1	1,157			(42)	1,115
76	Tax Impact	(244)	(84)		9	(319)
77	Series 07-1	1,300			(33)	1,267
78	Tax Impact	(89)	(89)		2	(175)
79		4,267	(193)	-	(388)	3,686
80						
81	TOTAL DEFERRED CHARGES	14,059	3,344	1,185	(2,527)	16,062
82						

83 Note 1: 2007 opening Deferred Charges balance has been increased by the Discount Forfeit defence costs of $138K ($206K before tax).

SCHEDULE 2 – EARNED RETURN

		Actual 2006	Forecast 2007	Forecast 2008
			($000s)	
1	SALES VOLUME (GW.h)	3,040	3,096	3,087
2				
3	ELECTRICITY SALES REVENUE	203,362	210,452	219,815
4				
5	EXPENSES			
6	Power Purchases	67,576	66,938	67,403
7	Water Fees	8,371	7,904	7,858
8	Wheeling	3,840	3,471	3,622
9	Net O&M Expense	32,337	33,796	36,248
10	Property Tax	10,275	10,637	11,176
11	Depreciation and Amortization	26,746	30,932	34,356
12	Other Income	(5,153)	(5,273)	(5,030)
13	AFUDC	(2,360)	-	-
14	Incentive Adjustments	2,431	(1,206)	(1,284)
15	UTILITY INCOME BEFORE TAX	59,299	63,253	65,466
16	Less:			
17	INCOME TAXES	6,504	6,069	3,989
18				
19	EARNED RETURN	52,795	57,185	61,477
20	RETURN ON RATE BASE			
21	Utility Rate Base	674,773	744,115	822,847
22	Return on Rate Base	7.82%	7.68%	7.47%

Table 2 – A – 1 – Sales by Customer Class

		Actual 2006	Forecast 2007	Forecast 2008
			(GWh)	
1	Residential	1,091	1,155	1,193
2	General Service	598	637	686
3	Industrial	344	362	240
4	Wholesale	948	878	904
5	Lighting	16	13	13
6	Irrigation	43	51	51
7	Total Sales	3,040	3,096	3,087
8	Losses and Company Use	365	321	309
9	Gross Load	3,405	3,417	3,396

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

		Actual 2006	Forecast 2007	Forecast 2008 *
			($000s)	
10	Residential	87,446	92,626	96,014
11	General Service	46,844	49,888	54,293
12	Industrial	18,871	20,692	15,182
13	Wholesale	46,299	42,922	43,779
14	Lighting and Irrigation	3,902	4,324	4,426
16	Total	203,362	210,452	213,694
17				
18	* Forecast at 2007 approved rates			

Table 2 – A – 3 – Customers at Year-End

		Actual 2006	Forecast 2007	Forecast 2008
19	Residential	89,181	93,515	96,022
20	General Service	10,285	11,116	11,471
21	Wholesale	8	7	7
22	Industrial	37	40	36
23	Lighting & Irrigation	2,902	3,227	3,227
24	Total	102,413	107,905	110,763
25				
26	* 2007 Customers include 3,212 acquired from PLP			

Table 2 – B – Power Purchase Expense

		Actual 2006	Forecast 2007	Forecast 2008
			GW.h	
1	FortisBC	1,506	1,498	1,572
2	DSM	4	5	11
3	Power Purchases (net of surplus sales)	1,899	1,919	1,824
4	Total System Load (before DSM savings)	3,409	3,422	3,407
5	Less DSM	(4)	(5)	(11)
6	Total System Load (including DSM savings)	3,405	3,417	3,396
			($000s)	
7	Expense - Energy	56,264	56,439	55,317
8	Expense - Capacity	11,541	12,321	13,717
9	Upgrade Life Extension credits and other adjustments	(229)	(1,822)	(524)
10	Total Power Purchase Expense	67,576	66,938	67,403

SCHEDULE 3 – INCOME TAX EXPENSE

		Actual 2006	Forecast 2007	Forecast 2008
			($000s)	
1	UTILITY INCOME BEFORE TAX	59,299	63,253	65,466
2	Deduct:			
3	Interest on Non Rate Base Deferral Account	-	10	27
4	Interest Expense	26,112	28,813	31,762
5				
6	ACCOUNTING INCOME	33,187	34,430	33,678
7				
8	Adjustments to Accounting Income			
9	to arrive at Taxable Income			
10				
11	Deductions			
12	Capital Cost Allowance	30,730	38,119	44,421
13	Capitalized Overhead	8,382	8,836	9,062
14	AFUDC	2,360	-	-
15	Additions to Deferred Charges for Tax Purpose	2,325	-	-
16	Incentive & Revenue Deferrals	-	1,206	1,284
17	Financing Fees	-	933	933
18	All Other (net effect)	(1,180)	(875)	281
19		42,617	48,219	55,981
20				
21	Additions			
22	Amortization of Deferred Charges	2,221	2,813	2,527
23	Depreciation	24,525	28,119	31,829
24		26,746	30,932	34,356
25				
26	TAXABLE INCOME	17,315	17,143	12,052
27				
28	Tax Rate	34.12%	34.12%	31.50%
29				
30	Taxes Payable	5,908	5,849	3,796
31	Prior Years' Overprovisions/(Underprovisions)	(302)	31	-
32	Deferred Charges Tax Effect	898	189	193
33	Large Corporations Tax	-	-	-
34	Allowance for tax audit	-	-	-
35				
36	REGULATORY TAX PROVISION	6,504	6,069	3,989

SCHEDULE 4 – COMMON SHARE EQUITY

			Actual 2006	Forecast 2007	Forecast 2008
				($000s)	
1	Share Capital		128,000	148,000	168,000
2	Retained Earnings		144,724	143,329	159,899
3					
4	COMMON EQUITY - OPENING BALANCE		272,724	291,329	327,899
5					
6	Less:	Common Dividends	(10,200)	(11,800)	(13,400)
7					
8	Add:	Net Income	26,683	28,370	29,688
		Share Adjustment	(17,878)		
9		Shares Issued	20,000	20,000	20,000
10					
11	COMMON EQUITY - CLOSING BALANCE		291,329	327,899	364,187
12					
13	SIMPLE AVERAGE		282,027	309,614	346,043
14					
15	Adjustment for Shares Issued		(13,573)	(7,397)	(4,110)
16	Deemed Equity Adjustment		-	(4,571)	(12,794)
17					
18	COMMON EQUITY - AVERAGE		268,454	297,646	329,139

SCHEDULE 5 – RETURN ON CAPITAL

		Actual 2006	Forecast 2007	Forecast 2008
			($000s)	
1	Secured and Senior Unsecured Debt	385,968	437,718	489,468
2	Proportion	57.20%	58.82%	59.48%
3	Embedded Cost	6.49%	6.42%	6.36%
4	Cost Component	3.71%	3.78%	3.78%
5	Return	25,062	28,111	31,126
6				
7	Short Term Debt	20,352	8,752	4,240
8	Proportion	3.02%	1.18%	0.52%
9	Embedded Cost	5.16%	8.02%	15.00%
10	Cost Component	0.16%	0.09%	0.08%
11	Return (including fees)	1,050	702	636
12				
13				
14	Common Equity	268,454	297,646	329,139
15	Proportion	39.78%	40.00%	40.00%
16	Embedded Cost	9.94%	9.53%	9.02%
17	Cost Component	3.95%	3.81%	3.61%
18	Return	26,683	28,370	29,688
19				
20	TOTAL CAPITALIZATION	674,774	744,116	822,847
21	RATE BASE	674,774	744,116	822,847
22				
23	Earned Return	52,795	57,183	61,450
24				
25	RETURN ON CAPITAL	7.82%	7.68%	7.47%
26	RETURN ON RATE BASE	7.82%	7.68%	7.47%

FORECAST RETURN ON CAPITAL

		Approved 2007	Forecast 2008
1	Bond Yield per:		
2	10 year Government of Canada Bond Yield	4.150	4.500
3	Premium from 30 Year Bond Yield	0.069	0.049
4			
5	Forecast 30 Year Bond Yield	4.219	4.549
6	Add/Subtract 25% of yield under 5.25%	0.258	0.175
7	Adjusted Yield	4.477	4.724
8	Premium for Low Risk Utilities	3.895	3.895
9	BCUC Benchmark Forecast	8.372	8.619
10	Rounded Benchmark ROE	8.370	8.620
11	FortisBC Risk Premium	0.400	0.400
12	FortisBC Allowed ROE	**8.770**	**9.020**
13			
14	Rate Base		822,847
15	Equity Ratio		40%
16	Allowed ROE		9.02%
17	Net Earnings		29,688

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Sarah Khan 687-4134
Patricia MacDonald 687-3017
James L. Quail 687-3034
Ros Salvador 488-1315
Leigha Worth 687-3044

Barristers & Solicitors

Eugene Kung
Articled Student

Via email

November 22, 2007

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

Re: FortisBC Inc. –2008 Revenue Requirements Negotiated Settlement Agreement

BCOAPO *et al*. approves the 2008 Revenue Requirements Negotiated Settlement Agreement dated November 19, 2006, subject to the following wording change in Issue #2 - "Income Tax" under Tab 3 (page 3 of the final NSA) that has been agreed to by BCUC staff, FortisBC and BCOAPO *et al.*:

> "The expected federal corporate income tax reduction will be included in 2008 revenue requirements. If it is not enacted, the difference ~~is subject to Z-factor treatment.~~ will be captured in a deferral account and flowed through to 2009 revenue requirements".

We would like to thank Commission staff and the parties for their efforts in reaching the NSA

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

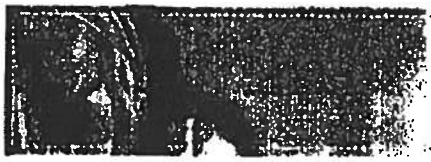
Original in file signed by

Sarah Y. Khan
Barrister & Solicitor

SYK/ar

Windows Live Hotmail

237104



My place

Log-in to Lavalife

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Manage folders

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Mail
Contacts
Calendar

So, what do you think?

New | Reply | Reply all | Forward | Delete | Junk

Move to | Options

FortisBC Inc. - 2008 Revenue Requirements Application

From: **Tomen, Rose BCUC:EX** (rose.tomen@bcuc.com)
You may not know this sender. Mark as safe | Mark as unsafe
Sent: November 19, 2007 11:13:29 AM
To: philip.nakoneshny@bcuc.com; Grant, Bill J BCUC:EX (bill.grant@bcuc.com); Yang, Jeffrey BCUC:EX (Jeffrey.Yang@bcuc.com); Chong, Doug BCUC:EX (doug.chong@bcuc.com); joyce.martin@fortisbc.com; david.bennett@fortisbc.com; dennis.swanson@fortisbc.com; michael.mulcahy@fortisbc.com; vkumur@grandforks.ca; alwait@telus.net; ludob@horizontec.com; VE7KH@hotmail.com; skhan@bcpiac.com; cmcneely@kelowna.ca; rleslie@city.nelson.bc.ca; terry.andreychuk@penticton.ca; kostraat@summerland.ca; Flintoff, Don BCUC:EX (Don.Flintoff@bcuc.com)
Cc: regulatory@fortisbc.com
FortisBC ...pdf (118.9 KB), FortisBC ...pdf (43.7 KB) Security scan upon download

Attaching Commission letter dated November 19, 2007 and a black-lined version of the changes to the preliminary Negotiated Settlement Agreement.

<<FortisBC 2008RRA NSA Nov 19 2007.pdf>> <<FortisBC 2008RRA NSP Blackline Nov 19 2007.pdf>>

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Rose Tomen (for)
William J. Grant
Transition Advisor
B.C. Utilities Commission
(Tel) 604-660-4700 (Fax) 604-660-1102
e-mail: bill.grant@bcuc.com

Nov 19/07

BCUC.
Attention: Jeffrey Yang. (Due Thurs. Nov22/07)
Received, reviewed & accepted.
Beryl (Jonas) Goodman (+ for Eric).
c/o VE7KH@hotmail.com. Ph. 1.250.495.6702

I.M.E.U.

Interior Municipal Electrical Utilities
Cities of Kelowna, Penticton, Grand Forks, District of Summerland, Nelson Hydro

November 22, 2007

Via Email

William J. Grant
Transition Advisor
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver BC V6Z 2N3

Dear Mr. Grant:

Re: FortisBC Negotiated Settlement
2008 Revenue Requirements Application

The IMEU is in receipt of your letter dated November 19, 2007 requesting acceptance of the Negotiated Settlement Agreement (NSA) for the FortisBC 2008 Revenue Requirements Application.

We understand that a wording change in the section of the NSA discussing Income Tax has been agreed upon between BCOAPO, FortisBC and BCUC Staff. We have been in contact with Sarah Khan and are also in agreement with that change. We further confirm that the IMEU accepts the remainder of the NSA as attached to your November 19 letter.

If you have any questions or concerns, please contact the undersigned at (250) 352-8212, or by e-mail at rleslie@nelson.ca

Respectfully submitted,

Russell Leslie, P.Eng
Chairman, IMEU

cc: IMEU group
Participants

Yang, Jeffrey BCUC:EX

From: Al Wait [alwait@telus.net]
Sent: Wednesday, November 21, 2007 4:38 PM
To: Yang, Jeffrey BCUC:EX
Subject: FortisBC 2008 NSP

Mr. Yang:

I wish to confirm that I am in agreement with the FortisBC Negotiated Settlement for 2008 recently completed in Kelowna.

Alan Wait

Fortis BC
2008 Revenue Requirements Application
Response to Negotiated Settlement Agreement

By: Ludo Bertsch, Horizon Technologies Inc.
Date: Nov 22, 2007
BCUC Project Number: 3698478

Background

Ludo Bertsch, participant in the Negotiated Settlement Process (NSP), has received support from a number of companies and individuals including:

- Alternergy Systems
- Andrew Illingworth
- Avalon Alliance
- BC Sustainable Energy Association – Okanagan chapter
- Best Western Inn Kelowna
- Coast Energy Management Collaborative
- Complete Home Energy Ltd.
- Dan Huang
- David Smith, member of the Canadian Institute of Planners and Planning Institute of BC; Planning Director, Peachland, BC
- Delta Geothermal Limited
- Dr Gord Lovegrove, P.Eng, UBC Okanagan
- Dunlop Renewable Energy Ltd.
- Eco Wise Water Systems Ltd.
- Energy Solutions for Vancouver Island
- Erin Radomske, Biology Department, Okanagan College
- Gail Hourigan
- Geoff Hann, P. Eng
- GeoTility Systems Corp.
- Greig Crockett, retired lawyer
- Horizon Technologies Inc.
- Intelligent Database Solutions Inc.
- IPS Integrated Power Systems
- J LeCavalier & Associates Inc.
- Jenergy Technologies
- Kelowna Kasugai Sister City Association
- Komatsu Japanese Market
- Naramata Conservation
- Okanagan Environmental Industry Alliance
- Okanagan Sustain Homes
- Quantum Wind Power Corp.

- Rob Dahl, teacher, Springvalley Middle School
- Robert J. Dantzer, P. Eng
- S2 Innovative Products Group Ltd.
- S. Wright Logistics, Management, Consulting
- Swiss Solar Tech
- Terra Firm Inc.
- Terra Geothermal Corp.
- Tigress Ventures
- The Wellness Spa
- Wendy Wright
- Windterra Systems Inc.

We do not support the Negotiated Settlement Agreement as described in the document labeled "FortisBC Inc. 2008 Revenue Requirement Negotiated Settlement Agreement". Our suggested changes and supporting reasons are described below:

NSP Issues

1.0 FortisBC Cost of Service and Rate Design Application (2008) (Sec. 3.8.2)

Issue Description: "*FortisBC forecast $600,000, before tax, for its Cost of Service Analysis and Rate Design Application*"
Resolution: "*For budget purposes, the forecast will be reduced to $400,000, before tax*"
Our submission: Add more description to the scope of the Rate Design Application for the budget of $600,000, include general tariffs for customers to sell power back to FortisBC, include budget line items (e.g. "Stakeholder Consultation"), and have meaningful engagement of stakeholders before submitting applications, such as the Rate Design application and the Advanced Meter Infrastructure CPCN.

The BCUC Order in response to Time-of-Use rates for FortisBC states: "*FortisBC is directed to file a Rate Design application on or before September 1, 2008. The Rate Design application should include a proposal for Time-of-Use rates that will apply to all customers within the merged PLP/FortisBC service area.*"[1]

The FortisBC update of November 1, 2007 provided a cost estimate for the Cost of Service and Rate Design Application (RDA) at $600,000[2] with specific

[1] BCUC Order G-115-07, Sept. 21, 2007
[2] FortisBC 2008 RRA Exhibit B-1-2, Tab 3, Section 3.8.2 vi, Page 30

line item costs. No further description of the scope of the RDA was included with the cost estimate.

Without such a description, there is a wide range of options that the RDA could cover and correspondingly a wide range of costs. For example, here are several of those options:

1. FortisBC's RDA might only cover the Time-of-Use rates.

2. On the other hand, FortisBC's RDA could cover similar topics as those in BC Hydro's 2007 RDA, which "*sets the foundation for BC Hydro's future rate design proposals*"[3].

3. Yet another option for FortisBC's RDA is to implement new rates such as allowing customers which generate their own electricity (e.g. solar panels) to sell power back to FortisBC at prescribed rates. These rates help support the government's commitment to the 2007 Energy Plan released Feb 27, 2007 and the recently introduced Greenhouse Gas Reduction Targets Act (Bill 44).

   For example, BC Hydro has had a net metering program since 2004[4] where 5.4 c/kWh is paid for excess electricity from a customer for installations up to 50kW. BC Hydro is presently proposing a "Standing Offer Program"[5] in which approx 5 c/kWh to 10 c/kWh is paid for larger customers.

   Ontario Hydro has a "Renewable Energy Standard Offer Program"[6] established in 2006 modeled on the best practice in European countries where small hydro and wind are paid 11 c/kWh and solar energy are paid 42 c/kWh.

Without a further clarifying description of the scope for the Rate Design Application, we submit that is not possible to gauge whether or not the stated budget is suitable.

The resolution of the NSP agreement to reduce the budget to $400,000[7] is also evidence of the need for this description. Without the RDA scope description, a reduction in the budget may result in a smaller scope of the RDA. Similarly, there may be more support from Intervenors and the BCUC for a larger budget if a wider scope for the RDA is presented.

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[3] BC Hydro 2007 RDA Exhibit B-1, page 3
[4] BC Hydro Electric Tariff, Schedule 1289, March 10, 2004
[5] BC Hydro Standing Offer Program Rates, Revised July 5, 2007
[6] Ontario Hydro Renewable Energy Standard Offer Program
[7] FortisBC RRA NSP, "FortisBC Cost of Service and Rate Design Application" issue

The specific line items for the reduced budget of $400,000 are not provided, so it is not clear where the reductions are expected to be made. In particular, it is not clear if the "Stakeholder Consultation" budget of $50,000[8] of the original will be reduced for this new budget estimate.

An indication of the challenges of a rate design application for FortisBC and the anticipated response from the BCUC are demonstrated in the 2007 Rate Design Application by BC Hydro. BCUC's response to BC Hydro's application also demonstrates the Commission Panel's support of not only substantial stakeholder engagement, but also early engagement.

The Commission Panel made overall comments on BC Hydro's RDA in its latest decision in a section called "Views of the Commission Panel on the Application and Determination"[9]:

> "*The Commission Panel is struck by the limited scope of the matters on which BC Hydro chose to engage with its stakeholders, and the minimal engagement with them in the process of developing the RDA, particularly since its last RDA was filed in 1991 – sixteen years ago. Given the amount of strategic and policy direction BC Hydro has received in the intervening years by way of direction from the Commission, and from its Shareholder, the Province, by way of the 2002 and 2007 Energy Plans, and in point of fact from the public pronouncements of its own executive, as highlighted in Sections 1 and 2 of this Decision, the Commission Panel finds BC Hydro's response disappointing.*"[10]
>
> "*. . . clearly illustrates that it did not engage with its stakeholders to any meaningful degree on the fundamental role that rates, and their structure, can, and should, play in the achievement of the strategic agenda that has been set for it.*"[11]
>
> "*It is clear that Intervenors were not provided the opportunity to participate in meaningful dialogue as to the 'issues and proposals to be addressed in the F2008 RDA' but rather were informed as to what BC Hydro had decided was going to be brought forward, and given limited opportunity to comment on a narrow range of issues and options of a non-strategic nature. Given that, the Intervenors have been left with no choice but to put their agendas for constructive change before this Commission Panel.*"[12]

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[8] FortisBC 2008 RRA Exhibit B-1-2, Tab 3, Section 3.8.2 vi, Page 30
[9] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, section 2.7
[10] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 56
[11] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 56
[12] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 57

> "*The Commission Panel contrasts the Stakeholder consultations BC Hydro conducted in order to inform the 2007 RDA, with those it conducted in support of its 2006 IEP/LTAP proceedings before this Commission. In finding that BC Hydro had appropriately engaged its stakeholders in those matters (IEP/LTAP Decision, May 11, 2007, p. 31) the Commission had before it a 286 page document entitled 'First Nations and Stakeholder Report (ibid p. 27). In this proceeding, BC Hydro filed a 20 page 'Stakeholder Engagement Summary' fully 40 percent of which is concerned with the relatively small and unique E-Plus customer subset.*"[13]

> "*The Commission Panel also observes that a sense of urgency appears to be missing in the 2007 RDA, which contradicts with the message to be found in the external communications of the BC Hydro Executive. BC Hydro's assertion that it has conducted significant rate design work over the past three years (Opening Statement, Exhibit B-24) is at odds with the absence of innovative proposals in the 2007 RDA.*"[14]

Further indications of the need for stakeholder engagement are demonstrated in BC Hydro's proposed changes to its Large General Service Rates in the same RDA[15]:

> "*The evidence before the Commission Panel is that BC Hydro's stakeholder engagement process consisted of two workshop meetings at which only two options (one of which retained a declining block structure) were presented to customers, and that part of BC Hydro's proposed mitigation was an offer of participation in its Power Smart programs, which were programs already in existence.*

> ***The Commission Panel finds that BC Hydro's proposed restructuring of its Large General Service class was ill-conceived and poorly executed. The proposal is denied.***"[16]

> "*The Commission Panel is also concerned that while it heard statements from BC Hydro that further structural changes to the Large General Service cannot be undertaken until after its proposed phasein period, it did not receive any indication of what those changes may look like, and as a result the Commission Panel cannot be sure that where BC Hydro's proposal takes the class would be a logical place to start further structural changes. In the Commission Panel's view the stakeholder engagement should start with the long view rather than vice versa.*"[17]

[13] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 58
[14] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 58
[15] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, section 4.4
[16] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 162
[17] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 162

"**Accordingly, BC Hydro is directed to commence meaningful stakeholder engagement with its Large General Service customers to develop, and file with the Commission an application for a rate structure or structures that encourage conservation without unduly benefiting or harming any of its customers in that class.**"[18]

In summary, we submit that:

a) ***FortisBC should provide more description to the scope of the Rate Design Application to support its original budget of $600,000.***

b) ***If FortisBC changes its budget from $600,000, that new budget should indicate the amounts for specific line items, including "Stakeholder Consultation".***

c) ***FortisBC should include general tariffs for customers to sell power back to FortisBC in its upcoming RDA application.***

d) ***FortisBC should have meaningful engagement of stakeholders before submitting applications, such as the Rate Design Application and the Advanced Meter Infrastructure CPCN.***

2.0 Demand Side Management (Sec. 7.2.7)

Issue Description: Set 2008 DSM projection at 19.5 GWh
Resolution: Maintain 2008 DSM projection at 19.5 GWh
Our submission: Increase DSM projection to 23.9 GWh or higher

The DSM expenditure projections were developed as part of the 2007-2008 Capital Expenditure Plan released on July 26, 2006[19]. The July 26, 2006 plan notes the following projections:

Total Savings (GWh) – July 26, 2006:

2006	2007	2008
20.5	21.8	19.5

[18] BC Hydro 2007 Rate Design Application, BCUC Decision Phase 1, October 26, 2007, pg 163
[19] FortisBC 2007-2008 Capital Expenditure Plan, July 26, 2006

The actual energy savings to year-end is now projected to be 28.5 GWh[20], which is 31 percent higher resulting in the following table:

Total Savings (GWh) – (from 2008 RRA Update):

2006	2007	2008
20.5	28.5	19.5

In the FortisBC 2007 RRA, the DSM Energy savings[21] over the previous years (2002 – 2005) were noted and are added to create the table below:

Total Savings (GWh) – (from 2007 RRA & 2008 RRA Update):

2002	2003	2004	2005	2006	2007	2008
16.3	18.5	21.7	22.7	20.5	28.5	19.5

There is a clear trend toward increasing savings. There is appropriately a 75% increase from 2002 to 2007.

The FortisBC RRA proposal to set the 2008 estimate to 19.5 GWh puts it below the 2004 level, even though all years since 2004 have been above that level.

One method to analyze the trend is to use a three year moving average similar to the FortisBC safety and health metrics[22]. The three year moving average results would be:

3 Year Moving Average - Total Savings (GWh):

2005	2006	2007	2008
18.8	21.0	21.6	23.9

This gives an indication to the trend of the DSM savings, on top of which other parameters may adjust the trend accordingly. For example, the 2007 BC Energy Plan[23] clearly places an emphasis on DSM which would tend to further increase the 2008 levels (see next item for further discussion on the new BC Energy Plan).

It is not unusual for FortisBC to update its Capital Expenditure Plan according to the latest information - in the November 1, 2007 submission FortisBC

[20] FortisBC 2008 RRA Exhibit B-2, BCUC IR#1, A53.1.3
[21] FortisBC 2007 RRA BCUC IR#1, A35.1
[22] FortisBC 2008 RRA, Exhibit B-1, Tab 8, Section 8.1.1
[23] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan

updated 15 capital projects[24], but did not update the DSM plan.

In summary, we submit that:

> ***The projected 2008 DSM Savings level should be at least 23.9 GWh.***

3.0 2007 BC Energy Plan

Issue Description: - nil -
Resolution: "*Fortis will continue to consider the BC Energy Plan in its 2008 projects and applications.*"
Our submission: "*Fortis will consider the 2007 BC Energy Plan in all its 2008 projects and applications.*"

The 2008 FortisBC RRA's application date was 7 months after the 2007 BC Energy Plan, which was released on February 27, 2007[25].

The new Energy Plan determined that utilities should explore new rate structures that encourage energy efficiency and conservation, and should pursue cost effective and competitive demand side management[26].

In response to Horizon's IR#1, FortisBC stated that "*It will take some time to consider the fifty-five policy items, firstly to determine which are relevant to FortisBC, secondly to determine how best to proceed and thirdly to complete due process.*" "*The Company*" . . . ."*will incorporate the relevant elements of the Energy Plan policy action items into the next DSM business plan*".[27]

FortisBC has not committed to a firm timeframe for consideration of the new Energy Plan policy items other than consideration in the next DSM business plan. Without such timeframe, FortisBC could effectively avoid such consideration by taking an extraordinary length of time.

In addition, we submit that FortisBC has already had ample time to consider the new BC Energy Plan - other utilities have already considered the new BC Energy Plan in their applications as the examples below indicate.

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[24] FortisBC 2008 RRA, Exhibit B-1-2, Tab 7, Appendix 1
[25] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan
[26] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, Policy Actions #3 and #4
[27] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A1.1

For example, BC Hydro considered the new plan after only 16 days in their March 15, 2007, Rate Design Application. In the section "Context for the 2007 Rate Design Application"[28] BC Hydro states:

> "*On February 27, 2007, the Provincial Government released its 2007 Energy Plan ('The BC Energy Plan: A Vision for Clean Energy Leadership'). The new Energy Plan sets out a large number of policy actions that place emphasis on energy conservation, energy efficiency and clean energy, and sets the direction to make British Columbia electricity self sufficient by 2016. An energy conservation target of meeting 50% of incremental resource needs through demand reduction by 2020 is established. With specific reference to utility rates, Policy Action 4 addresses the use of pricing structures as a demand side management tool to either discourage consumption overall, or shift demand to less costly periods. In particular:*
>
> > *'all utilities are encouraged to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy'.*
>
> *In this policy context BC Hydro's 2007 Rate Design Application sets the foundation for BC Hydro's future rate design proposals that will address the opportunities to use rate structures to contribute to the implementation of the government's 2007 Energy Plan. As noted in the section below BC Hydro is currently developing a long term rate strategy that will be informed by the 2007 Energy Plan and that will set the course for future rate changes and new rates that are designed to promote energy conservation and load management.*"[29]

Another example of an utility responding to the new BC Energy Plan is Terasen Gas. In its "System Extension and Customer Connection Policy Review" [30] with the BCUC, submitted on July 31, 2007, the new BC Energy Plan was prominent.

Terasen Gas in its introduction states:

> "*These changes will promote the responsible use of natural gas as a method to achieve energy efficiency and optimal use of resources within the broader energy market, which the Companies believe is consistent with the objectives of the 2007 BC Energy Plan – A Vision for Clean Energy Leadership (the "Energy Plan") released by the*

[28] BC Hydro 2007 Rate Design Application, Exhibit B-1, March 15, 2007, section 1.2
[29] BC Hydro 2007 Rate Design Application, Exhibit B-1, March 15, 2007, pages 2-3
[30] Terasen Gas System Extension & Customer Connection Policy Review, July 31, 2007

Ministry of Energy, Mines and Petroleum Resources in the spring of 2007."[31]

"The Companies believe that as a result of the current economic climate, and specifically the release of the BC Energy Plan, the connection and attachment policies should help meet societal and governmental policy and objectives, including promoting energy efficiency and conservation and also encourage the optimal consumer energy mix.

The Energy Plan is 'a made in BC solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way'[32]*. The document outlines 55 policy actions to help BC achieve this goal. The Terasen Utilities are supportive of the Energy Plan and believe that all energy utilities can and should play an integral role in helping BC meet and exceed the goals as set out in the Energy Plan.*

The Terasen Utilities see a number of policy actions for which achievement of their objectives will be dependent on changes in the approach to customer connection and attachment activities for both gas and electric utilities:

- *Policy Action #2, states 'Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia'*[33]*. This action further states that 'some programs, such as targeting household space and water heating, may not be justified on the basis of either electricity savings or gas savings alone. However, a coordinated effort may be cost-effective'.*
- *Policy Action #3 'Encourage[s] utilities to pursue cost effective and competitive demand side management opportunities'. The action further states that 'Energy efficiency is a critical piece of all BC utility resource plans'*[34]*.*
- *Policy Action # 4 'Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation'. The action further states that utilities are encouraged to 'explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency [and include] tariffs focused on promoting energy efficient new construction…'*[35]*.*

[31] Terasen Gas System Extension & Customer Connection Policy Review, July 31, 2007, Exhibit B-1, pg 1
[32] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, page 2
[33] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, page 1
[34] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, page 3
[35] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, page 4

• Policy Action # 24 states, 'A policy action of The BC Energy Plan is to review the BC Utilities Commission's role in considering social, environmental and economic costs and benefits as a part of its regulatory framework'[36].

The Companies believe that the changes requested in this Application are consistent with these Energy Plan policy actions."[37]

We submit that 8 months after the new Energy Plan release FortisBC should be required to consider the BC Energy Plan in **all** its projects and applications. Without the use of the word "***all***" (as per the NSP agreement resolution), FortisBC could choose not to consider the Energy Plan for essentially all its projects, and only consider the occasional project. By using the word "***all***" (as per our submission) FortisBC would still be able to decide on a project-by-project basis which, if any, policy actions are relevant to each particular project, but would be required at least to determine such relevancy.

It is also important to note that the new BC Energy Plan (e.g. 2007) is focus of this item and not the previous Energy Plan (e.g. 2002) - hence the addition of "***2007***" in our submission to clarify.

Our submission removes the words "***continue to***" as we submit that FortisBC has not given any evidence that it has considered the 2007 BC Energy Plan in this application.

Therefore, we submit that the statement in the NSP regarding the Energy Plan should changed to:

> ***"Fortis will consider the 2007 BC Energy Plan in all its 2008 projects and applications."***

[36] FortisBC 2008 RRA, Exhibit B-2, Horizon IR#1, A14.1, 2007 BC Energy Plan, page 6
[37] Terasen Gas System Extension & Customer Connection Policy Review, July 31, 2007, Exhibit B-1, pages 3-4

FORTISBC

David Bennett
Vice President,
Regulatory Affairs & General Counsel

FortisBC Inc.
Regulatory Affairs Department
1290 Esplanade Box 130
Trail BC V1R 4L4
Fax: 1 866 605 9431
regulatory@fortisbc.com
www.fortisbc.com

November 23, 2007

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. 2008 Revenue Requirements
Negotiated Settlement Agreement

FortisBC Inc. ("FortisBC" or "the Company") approves the 2008 Revenue Requirements Negotiated Settlement Agreement ("NSA") dated November 19, 2007, including the following wording change with regard to Income Tax requested by BCOAPO:

> "The expected federal corporate income tax reduction will be included in 2008 revenue requirements. If it is not enacted, the difference ~~is subject to Z-factor treatment.~~ will be captured in a deferral account and flowed through to 2009 revenue requirements."

FortisBC would like to thank the Parties and Commission Staff for their efforts in reaching this Agreement and appreciates the letters of support for the NSA.

The Company considers it necessary to comment on a letter received on November 22, 2007 from Horizon Technologies Inc. ("Horizon"), which FortisBC understands is a company based outside of FortisBC's service territory that sells energy efficiency related consulting services. The Company respectfully submits that the letter, which does not support the NSA, should not be given any weight when considering the approval of the NSA. The Horizon letter raised three concerns with respect to (1) FortisBC Cost of Service Study and Rate Design Application, (2) Demand Side Management and (3) 2007 BC Energy Plan. FortisBC comments are as follows:

(1) FortisBC Cost of Service Study and Rate Design ("RDA")

The issues of scope, participation and recommendations relating to the FortisBC RDA are matters that should be addressed in the RDA and not the 2008 Revenue Requirements and NSA. Furthermore the determination of budgeted costs for the RDA is only meant to be an estimate of the revenue requirements impact of the process and not a definition or limitation of the scope of the FortisBC RDA. Finally, the adequacy of BC Hydro's RDA is arguably not relevant to FortisBC's RDA and certainly not relevant to FortisBC's Revenue Requirements Application and NSA.

(2) Demand Side Management

The Demand Side Management ("DSM") program was addressed and approved in the 2007 and 2008 Capital Expenditure Plan application. The Company will file another Capital Expenditure Plan in 2008. The planned savings set out in the 2008 FortisBC Revenue Requirement Application were reviewed by the DSM Committee and are appropriate. FortisBC does not support the recommendation set out in the letter by Horizon.

(3) 2007 BC Energy Plan ("the Energy Plan")

FortisBC continues to support the 2007 BC Energy Plan and will continue to consider the Energy Plan in its 2008 projects and applications as appropriately stated in the NSA. Negotiating a specific standard and scope of consideration of the Energy Plan for all future regulatory applications is inappropriate and would go beyond the scope of FortisBC's 2008 Revenue Requirements Application and this NSA.

Sincerely,

David Bennett
Vice President,
Regulatory Affairs & General Counsel

cc Parties to the NSA