BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-193-08

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VANCOUVER, B.C. V6Z 2N3 CANADA
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
2008 Annual Review, 2009 Revenue Requirements and
Negotiated Settlement Process

BEFORE: L.F. Kelsey, Commissioner
P.E. Vivian, Commissioner
D.A. Cote, Commissioner

December 11, 2008

O R D E R

WHEREAS:

A. British Columbia Utilities Commission ("the 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 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. FortisBC invited stakeholders from the 2006 Settlement Agreement to negotiate the extension of the PBR Settlement. Negotiations were held on July 28, 2008 in Kelowna, BC and agreement in principle was reached to extend the PBR Settlement from 2009 to 2011 with a productivity factor of 2 percent for 2009, 1 percent for 2010 and 1 percent for 2011 and if the Consumer Price Index ("CPI") is above 3 percent in any of those years, then the productivity factor in that year will increase by the excess of CPI above 3 percent; and

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D. On September 4, 2008, FortisBC filed an application for Commission approval to extend the Settlement Agreement for the 2007-2009 Performance-Based Rate Plan for 2009-2011 (the "PBR Extension Application"). Following discussion among the Company, the stakeholders at the 2006 Settlement Agreement, and Commission Staff, on September 16, 2008, FortisBC withdrew its request for Commission approval of the PBR Extension Application; and

E. By Order G-141-08 dated September 25, 2008, the Commission established a Regulatory Timetable for the 2008 Annual Review and a 2009 Revenue Requirements Workshop on November 13, 2008 in Kelowna, BC, followed by an NSP on November 14, 2008; and

F. On September 26, 2008, FortisBC filed its Preliminary 2009 Revenue Requirements, which sought a 5.6 percent general rate increase effective January 1, 2009; and

G. On October 15, 2008, the Commission and Intervenors issued Information Requests to FortisBC which were responded to on October 29, 2008; and

H. On November 3, 2008, FortisBC filed the Updated 2009 Revenue Requirements Application, which incorporated financial results and forecasts as of September 30, 2008, including financial Performance Standards for the period October 1, 2007 to September 30, 2008, and sought a general rate increase that remained unchanged at 5.6 percent, effective January 1, 2009; and

I. As a result of the 2008 Annual Review on November 13, 2008 and 2009 Revenue Requirements Settlement discussions on November 14, 2008, a Settlement Agreement was proposed by FortisBC and agreed to by FortisBC and most Intervenors in attendance, with the participation of Commission Staff. The proposed Settlement Agreement, which results in a general rate increase of 4.6 percent effective January 1, 2009, was circulated to the participants and registered Intervenors on November 27, 2008; and

J. The proposed Settlement Agreement's financial schedules reflect the final 2009 Return on Equity of 8.87 percent, the disallowance of the Copper Conductor Replacement Certificate of Public Convenience and Necessity ("CPCN") by Order G-165-08, and the disallowance of the Advanced Metering Infrastructure CPCN by Order G-168-08; and

K. Letters of support to the proposed Settlement Agreement were received from the British Columbia Old Age Pensioners' Organization et al., Mr. Richard Tarnoff, the Okanagan Environmental Industry Alliance, the Interior Municipal Electrical Utilities, and FortisBC. No dissenting views were received; and

L. By the due date of December 8, 2008, no comments were received from any Registered Intervenors who had not participated in the Settlement negotiations; and

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

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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 supporting 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 11th day of December 2008.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

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

BRITISH COLUMBIA UTILITIES COMMISSION

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Log No. 26744

VIA E-MAIL

December 2, 2008

To: Registered Intervenors (FortisBC Inc.-2009RR)

Dear Registered Intervenors:

Re: FortisBC Inc. ("FortisBC")
Negotiated Settlement
2009 Revenue Requirements Application

Enclosed with this letter is the proposed settlement package for FortisBC's 2009 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Support and Comment received to date from the participants in the negotiated settlement process.

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 Monday, December 8, 2008. 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 W. Nakoneshny
for: William J. Grant

SM/rt
Attachments
cc: Mr. Dennis Swanson
Director, Regulatory Affairs
FortisBC Inc.
regulatory@fortisbc.com

FortisBC Inc. 2009 Revenue Requirements
Negotiated Settlement Agreement

Introduction

FortisBC Inc. ("FortisBC" or the "Company") filed its Preliminary 2009 Revenue Requirements on September 26, 2008. The materials within the Application were filed on the basis that an extension for the Performance Based Regulation ("PBR") would be negotiated between FortisBC and its Stakeholders for the years 2009-2011 and as such the Company developed its Application on that basis.

The Application reflected a general rate increase of 5.6 percent effective January 1, 2009. Following the submission of Information Requests by the Commission and Registered Intervenors and filing of responses, the Company filed an update to the 2009 Revenue Requirements Application on November 3, 2008 (the "Update"), incorporating financial results and forecasts as of September 30, 2008, final Performance Standards for the period October 1, 2007 to September 30, 2008, and other current information. The requested rate increase remained unchanged, as a net result of the adjustments, at 5.6 percent, effective January 1, 2009, subject to the determination of the 2009 Return on Equity arising from the Automatic Adjustment Mechanism, the outcome of a Negotiated Settlement Process ("NSP"), and the flow through of any adjustments as the result of a proceeding with the Commission for the additional sale of 25 GWh of energy to the City of Nelson from FortisBC.

The 2008 Annual Review and 2009 Revenue Requirements Workshop was held in Kelowna, BC on November 13, 2008. FortisBC and a group of Intervenors participated in a NSP on November 14, 2008, and reached a Settlement Agreement, which is described in this document. The Settlement Agreement results in a general rate increase of 4.6 percent effective January 1, 2009. Revenue Requirements Schedules, which also reflect the final 2009 Return on Equity of 8.87 percent, the disallowance of the Copper Conductor Replacement CPCN as per Order G-165-08, and the disallowance of the Advanced Metering Infrastructure CPCN as per Order G-168-08 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
T. Roberts	British Columbia Utilities Commission
D. Flintoff	British Columbia Utilities Commission
S. Mah	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

A. Love	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.
G. Isherwood	Consultant for The Interior Municipal Electric Utilities
Richard Tarnoff	FortisBC Ratepayer
N. Gabana	FortisBC Ratepayer
L. Bertsch	Consultant to the Okanagan Environmental Industry Alliance
D. Mayes	Okanagan Environmental Industry Alliance
D. Bennett	FortisBC Inc.
M. Mulcahy	FortisBC Inc.
D. Swanson	FortisBC Inc.

Settlement Agreement

The Parties accept the 2009 Revenue Requirements Application, including the Update, as filed, subject to the following:

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 3 – Revenue Requirements			
Contingent Liabilities – Vaseux Lake	Vaseux Lake incident costs have been presented as a deferred charge.	If and when the Vaseux Lake incident becomes a contingent loss under the CICA definition, FortisBC will commence reporting the amount in the financial statements and in the non-rate based, non-interest bearing deferral account. The disposition of this deferral account should be addressed in a separate application by FortisBC to the Commission following the court decision.	Exhibit B-4, A19.2 Exhibit B-1, Tab 3
Advanced Metering Infrastructure (AMI)	AMI investigative and CPCN Application costs have been presented as a deferred charge.	Set up a deferral account for AMI related expenditures that have been incurred in 2007 and 2008. FortisBC is to determine if it will be refiling an application for AMI. Until such time, FortisBC is to hold its AMI related expenditures in a deferral account to be reviewed with any future AMI application. Any prudency review may occur following Commission Decision on AMI.	Exhibit B-4, A20.1, A20.2, and A.49.1, A49.2, A49.3 BCOAPO IR Q.17a Exhibit B-1, Tab 3
ROW Encroachment by land developer	ROW Encroachment costs have been presented as a deferred charge.	Hold amount in deferral account pending court decision. If court decision is favourable, record recovered cost to the deferral account, then amortize the residual into rates.	Exhibit B-4, A51.1 and A51.2
City of Penticton – Carmi Substation Dispute Cost. $15,000 has been spent and FortisBC is requesting recovery of this cost in 2009	Carmi Substation dispute costs have been presented as a deferred charge.	Expense small cost items. $15,000 Dispute Cost should have been expensed in 2008.	Exhibit B-4, A50.1 and A50.2 Exhibit B-1, Tab 3, Sec. 3.7.2 IMEU Q18.1

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Stakeholder engagement	FortisBC should have meaningful engagement of stakeholders before applications are submitted to the BCUC.	FortisBC will engage in meaningful stakeholder engagement before the Rate Design Application (RDA), Cost of Service, Advanced Meter Infrastructure, DSM Study and Net Metering applications are submitted to the BCUC.	
Rate Design Application	The Rate Design Application budget for stakeholder engagement should be increased back to $50,000.	FortisBC will reallocate $50,000 of the RDA budget to stakeholder engagement.	
DSM Target	Increase the DSM target for 2009 from 25.3 GWh to 29 GWh, and adjust DSM expenditures accordingly.	In 2008 FortisBC has forecast DSM savings of 26.9 GWh and will continue to seek cost-effective improvements in 2009 in support of the new BC Energy Plan.	
Rate Design Application and the 2007 BC Energy Plan	Include description of Rate Design Application: "The Rate Design Application will address the 2007 BC Energy Plan policy #4 (which states "Explore with B.C. Utilities new rate structures that encourage energy efficiency and conservation") and will include general tariffs for customers to sell power back to FortisBC.	The Rate Design Application will address the 2007 BC Energy Plan policy #4 and will include general tariffs for customers to sell power back to FortisBC.	

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 4 – Financial Schedules			
Negotiation Cost of PPA	Current BC Hydro PPA Proceeding costs have been included as part of the Deferred Negotiation cost of the PPA.	Separate the cost of the current PPA Proceeding – about $40,000. Collect the cost in a non-rate based, non-interest bearing deferral account.	OEIA A12.4
Tab 5 – 2009 Load and Customer Forecast			
Nelson Export - The Company will be applying to recover this amount as a flow through charge to 2010 depending on the results of the current BCUC proceedings on this matter.	The Company has assumed 25 GWh of additional sales to the City of Nelson for 2009.	If the Commission determines it is not appropriate, FBC will adjust its sales forecast and reforecast its power purchase to reduce market purchases for 2009 and flow through the revenue requirement amount in 2010.	Exhibit B-4, A43.1 Exhibit B-1,Tab 5, Table 5.0, p. 4
System Losses - Reduction	The Company has included gross system losses of 8.9% for 2009. Although the Company believes the 8.9% to be an accurate forecast, it has accepted the 8.7% on a negotiated basis.	Given the actual data and the rate of improvement over the years, gross system losses will be 8.7 percent (decrease of approximately 0.3 percent from forecast 2008). System losses to be utilized in Revenue Requirements will be calculated on a two-year rolling average for the remainder of the PBR term.	Exhibit B-4. A58.1 and A58.2 Exhibit B-1, Tab 5, Appendix A, p. 15

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 6 – Power Purchase and Wheeling			
Generators: Canal Plant entitlement	The Company plans to continue the generator upgrades and life extensions. There are 2 units at Corra Linn, 1 unit at South Slocan and 4 units at Upper Bonnington that have yet to be completed. South Slocan unit 1 was previously approved (Order G-52-05) and the project is in progress. Corra Linn unit 1 was previously approved (Order G-147-06) and the project is in progress. Corra Linn unit 2 is expected to begin in 2009, and the business case has been submitted as part of the 2009/2010 Capital Plan (as Appendix A), There are 4 units remaining at Upper Bonnington that have not yet undergone an upgrade/life extension and have not yet received regulatory approval.	FortisBC to provide a business case analysis of any continuing benefits from future generator upgrades and life extensions. (4 units at Upper Bonnington)	Exhibit B-4, A68.1 and A68.2

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
BC Hydro Rate Increase	The Company has continued to include the April 2008 BC Hydro interim rate increase for Power Purchases and Water Fees and has not included any increase with respect to April 2009. The Company proposes to flow through a true up of the April 2008 increase as well as the final April 2009 increase once approved by the Commission.	Given the likelihood of the final 2008 BC Hydro approved rate increase being lower than the current approved interim increase, effective January 1, 2009 FortisBC will stop collecting the interim BC Hydro rate increase from customers. Any resulting difference in power purchase costs and water fees will be carried in a rate base deferral account. Pending a BCUC decision on the BC Hydro rate increase, the Company will true up the April 2008 increase and April 2009 increase on or after April 2009. This true up will be submitted to the BCUC for tariff approval and will include the true up of power purchase costs, water fees, and the carrying costs of the deferral account related to the BC Hydro approved rate increase.	Exhibit B-1, Tab 3 and Tab 6

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 7 – Capital Expenditures			
Vehicle Expenditures	Vehicle Expenditures are forecast to be $1.3 million in 2009 and $2.9 million in 2010.	Levelize vehicle expenditures at $2 million per year for the term of the PBR.	Exhibit B-4, A20.3 - The primary reasons for the difference are an increase of $1.7 million in Information System expenditures and an increase of $1.9 million in Building Expenditures offset by reduction in expenditures for Vehicles. Capital Expenditure workshop slide 112.
Tab 8 – Performance Standard			
FortisBC is raising the forecasted all-injury frequency rate and the injury severity rate.	The Company has proposed an all injury frequency rate of 2.08 and an injury severity rate of 27.00.	2009 injury severity rate performance target should remain at the 2008 target of 17.53. The all injury frequency rate is accepted at 2.08.	Exhibit B-4, A74.1 through A74.9 Exhibit B-1, Tab 8 , pp. 6-8
Major Event Data	The Company calculates SAIDI and SAIFI after factoring out Major Event Data using the IEEE 2.5 Beta normalization methodology. The results are presented for Performance Target purposes.	The SAIDI and SAIFI should be calculated <u>with and without</u> the Major Event Data. The calculation of SAIDI and SAIFI before factoring out the Major Event Data is for information purposes only and does not constitute additional Performance Targets.	Exhibit B-1, Tab 8, p. 11 Exhibit B-4, A75.6 and A75.11

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Is the Vegetation management program effective?	FortisBC states: "In general, major weather event outages on FortisBC's system are *primarily the result of trees* that affect the transmission and distribution network including both new and older infrastructure".	FortisBC to provide a report to identify if the vegetation management program is effective for major event days. To address the question "Are the design standards used by FortisBC still appropriate for the weather conditions in the service area?" The design limit will be expressed in km/hr. This report will be produced on or before the 2009 Annual Review and is intended for informational purposes only.	A75.8, A75.9, A75.10
Customer Average Interruption Duration Index ("CAIDI"). The CAIDI calculation is SAIDI/SAIFI.	System Reliability is important to both FortisBC and its customers.	FortisBC is to present a plan involving the worst performing circuits to lower SAIDI to improve CAIDI.	Exhibit B-4, A75.4 and A75.13
Performance Standards	There is ambiguity about how many standards the Company must meet to earn an incentive.	The 2012 oral public hearing or the next Performance Based Rate Application review process will examine the criteria for meeting performance standards.	

FortisBC Inc.
2008 Annual Review and 2009 Revenue Requirements
Negotiated Settlement Agreement

ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 9 – 2008 Proposed PBR Extension			
Term	The Company proposed a three year extension of PBR to 2011.	Three-year extension through 2011. The 2012 application to be reviewed by oral public hearing.	BC Gas Decision 2003
Productivity Improvement Factors ("PIF") for 2009-11.	The Company proposed PIF's of 2% for 2009, 1% for 2010 and 1% for 2011 and an effective capping of CPI at 3% each year.	PIF's will be 3% - 1.5% - 1.5% for 2009-2010-2011. Should inflation be in excess of 3 percent, the excess is added to the PIF which effectively caps the CPI at 3 percent.	Exhibit B-4, A3.1 Exhibit B-1, Tab 2 & Tab 9 Exhibit C4-2, BCPIAC letter
Tab – Appendix 2 – Accounting Changes			
IFRS and Future Income Taxes No Surprises		Accept FortisBC's proposal in Appendix 2, p. 3 and p. 5.	Exhibit B-4, A4.1, A18.1 and A18.4 Exhibit B-1, Tab 9, and Tab Appendix 2
Miscellaneous			
Multi Year Rate Forecast	The Company only prepares a rate forecast for the year(s) in which they are seeking rate approval. Customers generally, and the IMEU in particular, will benefit from multi-year rate projections to assist them in budgeting and other purposes.	The Company will provide, on a reasonable efforts basis, a multi year rate forecast as part of its annual reviews. The multi year rate forecast will at minimum cover the remaining term of the PBR. It is recognized that this is a multi year forecast and as such, the Company will not be held responsible for its eventual accuracy.	

The
British Columbia
Public Interest
Advocacy Centre

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Articled Student	

VIA EMAIL

November 28, 2008

Our File: 7402

William J. Grant
Transition Advisor
Regulatory Affairs and Planning
BC Utilities Comission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Project No. 3698522 - FortisBC 2008 Annual Review & 2009 Revenue Requirements

BCOAPO *et al.* approves the 2009 Revenue Requirements Negotiated Settlement Agreement dated November 27, 2008.

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

Yours truly,

Sarah Khan
Barrister & Solicitor

c. Stuart Mah, BCUC
Dennis Swanson, Director, Regulatory Affairs, FortisBC Inc.
Registered Intervenors

Mah, Stuart BCUC:EX

From: Richard Tarnoff [rgt@nethop.net]

Sent: Monday, December 1, 2008 12:31 PM

To: Tomen, Rose BCUC:EX; alvoe@nelson.ca; cmcneely@kelowna.ca; david.bennett@fortisbc.com; execdir@oeia.ca; dennis.swanson@fortisbc.com; Flintoff, Don BCUC:EX; george.isherwood@shaw.ca; Grant, Bill J BCUC:EX; kostraat@summerland.ca; ludob@horizontec.com; Mah, Stuart BCUC:EX; michael.mulcahy@fortisbc.com; Nakoneshny, Philip BCUC:EX; ngabana@telus.net; Roberts, Tony BCUC:EX; skhan@bcpiac.com; terry.andreychuk@penticton.ca; vkumar@grandforks.ca

Subject: Re: FortisBC Inc. Negotiated Settlement 2009 Revenue Requirements Application

Ms. Rose Tomen
BC Utilities Commission

I have reviewed the final version of the Negotiated Settlement Agreement and endorse the wording as presented.

Yours truly

Richard Tarnoff

representing
Natural Resource Industries
Hedley Improvement District

FortisBC
2009 Revenue Requirements Application
Response to Negotiated Settlement Agreement

By: Ludo Bertsch, Horizon Technologies Inc. (250) 592-1488
For: Okanagan Environmental Industry Alliance
Date: December 1, 2008
BCUC Project Number: #3698522

On behalf of the Okanagan Environmental Industry Alliance (OEIA), I am pleased to report that OEIA accepts the Negotiated Settlement Agreement as described by the November 27 documents of the Introduction, Summary and Financial Schedules.

Yours truly,

Ludo Bertsch
representing Okanagan Environmental Industry Alliance

Horizon Technologies
ludob@horizontec.com
(250) 592-1488

I.M.E.U.

Interior Municipal Electrical Utilities

Cities of Kelowna, Penticton, Grand Forks, District of Summerland, Nelson Hydro

Suite 101, 310 Ward Street, Nelson, British Columbia, V1L 5S4

• Phone: (250) 352-8212 • Facsimile: (250) 352-6417 •

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December 1, 2008

VIA ELECTRONIC MAIL

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Sirs/Mesdames:

RE: FortisBC Inc. (FortisBC)
Negotiated Settlement
2009 Revenue Requirements Application

The Interior Municipal Electric Utilities (IMEU) supports the negotiated settlement agreement as circulated by Commission Staff on November 27, 2008.

That notwithstanding, as noted by the IMEU in its submission as part of the FortisBC 2009/10 Capital Expenditure/System Development Plan application, the primary concern of the IMEU in both of these proceedings is that of rate impact. As previously expressed, rate increases of five percent or more are of great concern to customers. The IMEU respectively suggests that FortisBC be urged to considered mechanisms, such as an extended capital expenditure schedule, or an annual cap on expenditures, which could lessen annual rate increases. The IMEU recognizes that delaying necessary expenditures may have some impact on reliability metrics, but we believe that ways can be found to provide both acceptable reliability and reasonable rate increases.

The IMEU wishes to thank the Commission Staff for their assistance, and other interveners for their input and cooperation.

Yours truly

Alexander Love
On behalf of IMEU

c: dennis.swanson@fortisbc.com
registered intervenors

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

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December 2, 2008

Via Email

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 2009 Revenue Requirements Negotiated Settlement Agreement ("NSA") dated November 27, 2008.

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.

FortisBC agrees with the resolution regarding Performance Standards, however the Company considers it necessary to comment on the issue of ambiguity regarding how many Performance Standards the Company must meet to be eligible for a financial incentive. As agreed to in the 2006 NSA, failure to meet one or more targets does not necessarily constitute unacceptable overall performance. While the Company understands that some stakeholders may view the Performance Standards as a simple count of targets met versus targets not met in determining the Company's eligibility for a financial incentive, the primary test for inadequate performance and, hence, consideration for disqualifying the Company from receiving a financial incentive remains:

> "If the Company earned a financial incentive, did it do so as a direct result of allowing or causing its performance to deteriorate in a material way."

FortisBC is accountable for its quality of service by reporting on its Performance Standards at the annual reviews, and agrees that stakeholders should continue to be afforded the opportunity to scrutinize the Company's performance results as they relate to whether the Company earned a

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financial incentive as a direct result of allowing or causing performance to deteriorate in a material way.

FortisBC strives for continual improvement in the overall quality of service provided to its customers, and believes the Performance Standards as agreed to in the 2006 NSA offer an indicator of this improvement. As has been evidenced in previous annual reviews, the Company's failure to meet one or more targets has not been accepted as constituting unacceptable overall performance, and it is these results by which the Company believes that on the whole, it has been successful in continuing to improve the quality of service provided to its customers.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

cc Parties to the NSA

2009 Revenue Requirements
Negotiated Settlement Agreement

Financial Schedules

FortisBC Inc.

Revenue Requirements Overview

		2009 Revenue Requirements		
		Approved 2008	Increase or (Decrease)	Forecast 2009
			($000s)	
1	Sales Volume (GWh)	3,087		3,107
2	Rate Base	822,847		907,977
3	Return on Rate Base	7.47%		7.38%
4				
5	**REVENUE DEFICIENCY**			
6				
7	**POWER SUPPLY**			
8	Power Purchases	68,538	910	69,448
9	Water Fees	7,858	428	8,286
10		76,396	1,338	77,734
11	**OPERATING**			
12	O&M Expense	45,310	1,263	46,573
13	Capitalized Overhead	(9,062)	(253)	(9,315)
14	Wheeling	3,622	388	4,010
15	Other Income	(5,030)	115	(4,915)
16		34,840	1,513	36,353
17	**TAXES**			
18	Property Taxes	11,176	385	11,561
19	Income Taxes	3,989	365	4,354
20		15,165	750	15,915
21	**FINANCING**			
22	Cost of Debt	31,762	3,041	34,803
23	Cost of Equity	29,688	2,527	32,215
24	Depreciation and Amortization	34,356	3,148	37,504
25		95,806	8,716	104,522
26				
27	Prior Year Incentive True Up	22	151	173
28	Flow Through Adjustments	(42)	(393)	(435)
29	AFUDC / CWIP shortfall	895	(895)	-
30	ROE Sharing Incentives	(2,159)	978	(1,181)
31		(1,284)	(159)	(1,443)
32				
33	**TOTAL REVENUE REQUIREMENT**	220,923	12,158	233,081
34				
35	Interest on Non Rate Base Deferral Account	27	(27)	-
36	ADJUSTED REVENUE REQUIREMENT	220,950	12,131	233,081
37	**Less: REVENUE AT APPROVED RATES**			222,847
38	**REVENUE DEFICIENCY for Rate Setting**			10,234
39				
40	**RATE INCREASE**			**4.6%**

SCHEDULE 1
UTILITY RATE BASE

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
1	Plant in Service, January 1	943,920	1,062,070	1,173,113
2	Net Additions	118,150	111,043	119,750
3	Plant in Service, December 31	1,062,070	1,173,113	1,292,863
4				
5	Add:			
6	CWIP not subject to AFUDC	13,112	6,865	6,865
7	Plant Acquisition Adjustment	11,912	11,912	11,912
8	Deferred and Preliminary Charges	14,473	17,337	23,611
9				
10		1,101,567	1,209,228	1,335,251
11	Less:			
12	Accumulated Depreciation			
13	and Amortization	250,323	275,935	303,463
14	Contributions in Aid of Construction	78,351	87,388	97,489
15		328,674	363,322	400,952
16				
17	Depreciated Rate Base	772,893	845,905	934,299
18				
19	Prior Year Depreciated Utility Rate Base	712,911	772,893	845,905
20				
21	Mean Depreciated Utility Rate Base	742,902	809,399	890,102
22	Add:			
23	Allowance for Working Capital	6,519	7,425	7,018
24	Adjustment for Capital Additions	(2,878)	(14,017)	10,857
25				
26	Mid-Year Utility Rate Base	746,543	802,807	907,977

Schedule 1A
No Rate Base Assets

		BCUC Order No. (Note 1)	Forecast 2009
			($000s)
1	Future income taxes		82,168
2	Brilliant Terminal Station capital lease	G-2-04	4,484
3	Other post-retirement benefits	G-52-05	4,083
4	Trail office building lease costs	G-41-93	1,409
5			92,144

Note 1:

With the exception of future income taxes, the Commission has already approved the recoverability of these items in customer rates as indicated by the related orders.

Table I - A (2008)
Utility Plant in Service as of December 31, 2008

Line	Account		December 31 2007	Additions	Retirements	December 31 2008
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	10,947	540	(84)	11,403
3	332	Reservoirs, Dams & Waterways	19,433	1,840	(80)	21,193
4	333	Water Wheels, Turbines and Gen.	54,503	2,478	(73)	56,908
5	334	Accessory Equipment	22,370	875	-	23,245
6	335	Other Power Plant Equipment	38,277	270	-	38,547
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			147,430	6,002	(237)	153,195
9		**Transmission Plant**				
10	350	Land Rights	7,079	-	-	7,079
11	350.1	Land Rights - Clearing	4,496	-	-	4,496
12	353	Station Equipment	135,378	35,314	(1,779)	168,913
13	355	Poles Towers & Fixtures	65,142	9,799	(966)	73,975
14	356	Conductors and Devices	62,601	9,780	(1,183)	71,198
15	359	Roads and Trails	817	-	-	817
16			275,513	54,892	(3,928)	326,477
17		**Distribution Plant**				
18	360	Land Rights	1,736	1,250	-	2,986
19	360.1	Land Rights - Clearing	5,856	1,250	-	7,106
20	362	Station Equipment	115,295	1,828	-	117,123
21	364	Poles Towers & Fixtures	105,392	9,118	(80)	114,430
22	365	Conductors and Devices	175,985	11,235	(80)	187,140
23	368	Line Transformers	83,699	6,642	-	90,341
24	369	Services	7,292	-	-	7,292
25	370	Meters	12,754	701	-	13,455
26	371	Installation on Customers' Premises	938	4,207	-	5,145
27	373	Street Lighting and Signal System	7,318	-	-	7,318
28			516,264	36,230	(160)	552,334
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	22,966	1,708	-	24,674
33	391	Office Furniture & Equipment	5,233	533	-	5,767
34	391.1	Computer Equipment	42,179	9,473	-	51,652
35	392	Transportation Equipment	16,447	2,733	-	19,180
36	394	Tools and Work Equipment	9,884	780	-	10,664
37	397	Communication Structures and Equipment	20,016	3,447	(432)	23,031
38			122,863	18,676	(432)	141,106
39						
40	101	**Plant in Service**	1,062,070	115,800	(4,757)	1,173,113
41	107.1	Plant under construction not subject				
42		to AFUDC	13,112			6,865
43	107.2	Plant under construction				
44		subject to AFUDC	44,956			52,799
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,132,050			1,244,688

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Table I - A (2009)
Utility Plant in Service as of December 31, 2009

Line	Account		December 31 2008	Additions	Retirements	December 31 2009
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	11,403	934	(199)	12,138
3	332	Reservoirs, Dams & Waterways	21,193	2,121	(215)	23,099
4	333	Water Wheels, Turbines and Gen.	56,908	13,169	(174)	69,903
5	334	Accessory Equipment	23,245	1,240	-	24,485
6	335	Other Power Plant Equipment	38,547	1,187	-	39,734
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			153,195	18,652	(588)	171,259
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,079	798	-	7,877
11	350.1	Land Rights-Clearing	4,496	798	-	5,294
12	353	Station Equipment	168,913	31,156	(2,829)	197,240
13	355	Poles Towers & Fixtures	73,975	12,080	(1,499)	84,556
14	356	Conductors and Devices	71,198	11,048	(1,499)	80,747
15	359	Roads and Trails	817	399	-	1,216
16			326,477	56,281	(5,827)	376,931
17		**Distribution Plant**				
18	360	Land Rights-R/W	2,986	671	-	3,657
19	360.1	Land Rights-Clearing	7,106	671	-	7,777
20	362	Station Equipment	117,123	-	-	117,123
21	364	Poles Towers & Fixtures	114,430	14,066	(25)	128,470
22	365	Conductors and Devices	187,140	11,362	(22)	198,480
23	368	Line Transformers	90,341	5,706	-	96,046
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,455	832	-	14,288
26	371	Installation on Customers' Premises	5,145	4,242	-	9,386
27	373	Street Lighting and Signal System	7,318	-	-	7,318
28			552,334	37,550	(47)	589,837
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	24,674	2,005	-	26,680
33	391	Office Furniture & Equipment	5,767	1,819	-	7,586
34	391.1	Computer Equipment	51,652	5,535	-	57,188
35	392	Transportation Equipment	19,180	2,000	-	21,180
36	394	Tools and Work Equipment	10,664	618	-	11,282
37	397	Communication Structures and Equipment	23,031	2,183	(432)	24,783
38			141,106	14,161	(432)	154,835
39						
40	101	**Plant in Service**	1,173,113	126,644	(6,894)	1,292,862
41	107.1	Plant under construction not subject				
42		to AFUDC	6,865			6,865
43	107.2	Plant under construction				
44		subject to AFUDC	52,799			81,485
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	1,244,688			1,393,125

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Table I - A - 1 (2008)
Additions to Plant in Service
for the Year Ending December 31, 2008

		CWIP Dec. 31, 2007	Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
			($000s)		
Hydraulic Production					-
1	P1U1 Upgrade & Life Extensions	-	-	-	-
2	P1U2 Headgate Rebuild	-	-	-	-
3	P1U3 Upgrade & Life Extension	23	468	-	491
4	P1U3 Headgate Rebuild	-	-	-	-
5	P1 Generator & Plant Cooling System	6	-	-	6
6	P2 Old Unit Repowering Phase 1	1,213	1,812	-	3,025
7	P3U1 Life Extension	3,183	2,935	6,118	-
8	P3U1 Headgate Rebuild	-	1	-	1
9	COR U1 Life Extension (replace Turbine)	-	948	948	-
10	P3U3 Life Extension	3,164	7,881	11,045	-
11	P3U3 Headgate Rebuild	449	479	-	928
12	P3 Poleyard Contaminated Site	-	149	-	149
13	P3U2 Bottom Ring Rebuild	-	53	-	53
14	P3 H/G Hoist Contr. Wire Rope	-	132	132	-
15	P1-P4 Upgrade Station Service Supply	-	541	541	-
16	All Plants Spare Unit Transformer	-	143	143	-
17	Generation Sustaining Under $500k	-	1,177	-	1,177
18	2007 PST Credit	-	29	-	29
19	P3 Completion	694	576	1,270	-
20	P3U2 Rebuild & Life Extension	(17)	-	-	(17)
21	P4U1 Headgate Rebuild	102	-	-	102
22	P1 Misc Upgrades	6	-	-	6
23	P2 Misc Upgrades	12	-	-	12
24	P3 Misc Upgrades	22	-	-	22
25	P4 Misc Upgrades	17	-	-	17
26		8,875	17,324	20,197	6,002
Transmission Plant					
27	Kootenay 230 KV Development	-	109	-	109
28	SOK Project (Vaseux Lake Terminal)	-	(97)	-	(97)
29	Okanagan Transmission Reinforcement	3,838	3,353	7,191	-
30	Benvoulin Distribution Source	-	500	500	-
31	Big White 138 KV Line & Substation	6,268	7,408	-	13,676
32	Ellison Distribution Source	3,690	9,020	12,710	-
33	Black Mountain Distribution Source	712	7,538	8,250	-
34	Fault Level Reduction	143	59	-	202
35	Naramata Rehabilitation	2,813	967	3,780	-
36	New East Osoyoos Source (Nk'Mip Sub)	-	181	-	181
37	Kettle Valley	15,539	4,947	-	20,486
38	Lambert Transformer # 2	(277)	-	-	(277)
39	Princeton Transformer Replace	(15)	7	-	(8)
40	Transmission Line Sustaining	-	2,730	-	2,730
41	Station Sustaining	1,172	5,280	-	6,452
42	Ootischenia Project	492	6,650	-	7,142
43	Capitalized Inventory & Transformers	6,865	-	6,865	-
44	Crawford Bay Cap Inc	2,183	9	-	2,192
45	Glenmore Substation New Feeder	-	97	-	97
46	WestBench Regulator Bank	-	2	-	2
47	Hedley Stepup Transformer	-	6	-	6
48	18 L Breaker @ Waneta	3	1,997	-	2,000
49		43,426	50,763	39,297	54,892

Table I - A - 1 (2008) Continued
Additions to Plant in Service
for the Year Ending December 31, 2008

		CWIP Dec. 31, 2007	Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
			($000s)		
	Distribution Plant				
50	New Connects System Wide	-	23,370	-	23,370
51	Distribution Sustaining	-	9,220	-	9,220
52	Small Cap Improvements	-	72	-	72
53	Small Cap Improvements Unplanned - 2007	-	107	-	107
54	Small Cap Improvements Unplanned - 2008	-	412	-	412
55	HOL1 - OKM1 Tie KLO Rd	-	131	131	-
56	GLE6 Fdr Hi Rd - Clifton	-	62	-	62
57	LEE2 - HOL5 Tie Add N.O.	-	510	-	510
58	Dilworth Development Loopfeed	-	384	-	384
60	GLE2 Spall/Springfield UG	-	1	-	1
61	HOL1-HOL2 Tie	19.5	137	0	156.5
62	LEE 2 Regulator	-	7	-	7
63	KER01 & KER02 Capacity Upgrades	-	6	-	6
64	PRI04 Capacity Upgrade	103	1,170	-	1,273
65	OKF03 Capacity Upgrade	120	112	-	232
66	CRA 02 Capacity Upgrade	-	4	-	4
67	Mckinley Landing Capacity Upgrade	1	413	-	414
68	VAL1 Feeder Capacity Upgrade	10	29	39	-
69		253	36,147	170	36,230
	General Plant				
70	Distribution Station Automation	181	1,227	-	1,408
71	Protection and Communications Rehabilitation	410	1,881	-	2,291
72	Vehicles	-	2,733	-	2,733
73	Metering	-	417	-	417
74	Information Systems	4,892	4,290	-	9,181
75	Telecommunications	-	257	-	257
76	Buildings	31	1,536	-	1,568
77	Furniture & Fixtures	-	252	-	252
78	Tools & Equipment	-	569	-	569
79		5,514	13,162	-	18,676
80	TOTAL	58,068	117,395	59,664	115,800

Additions to Plant in Service
for the Year Ending December 31, 2009

		CWIP Dec. 31, 2008	Expenditures 2009	CWIP Dec 31, 2009	Additions to Plant in Service
			(000s)		
	Hydraulic Production				
1	All Plants Spare Unit Transformer	143	1,074	-	1,217
2	LBO & UBO Comm. Network Comp.	-	95	95	-
3	All Plants Fire Safety Upgrade Ph.1	-	241	-	241
4	SLC U1 Life Extension (replace turbine)	6,118	8,021	14,139	-
5	SLC U1 Head Gate Rebuild	-	577	577	-
6	All Plants Public Safety & Security Ph.1	-	82	48	34
7	SLC U3 Life Extension (no Turbine)	11,045	2,016	-	13,061
8	UBO Old Unit Repowering (Ph.1)	0	1368.917615	1044.917615	324
9	All Plants Upgrade Station Service Supply	541	484	151	875
10	SLC H/G Hoist, Control, Wire Rope Upgrade	132	909	-	1,041
11	SLC Plant Completion	1,270	640	1,910	-
12	COR U1 Life Extension (replace Turbine)	948	4,310	5,258	-
13	COR U2 Life Extension (replace Turbine)	-	104	104	-
14	COR Spillway Gate Isolation Study	-	46	46	-
15	SLC Dam Rehabilitation Study	-	46	46	-
16	LBO Power House Crane Upgrade	-	174	-	174
17	COR Power House Crane Upgrade	-	172	-	172
18	COR East Wingdam Handrail Upgrade	-	78	-	78
19	All Plants Portable Headgate Closing Device	-	50	-	50
20	All Plants Spare Exciter Transformer	-	24	24	-
21	LBO Intake Area Upgrade Ph.1	-	393	-	393
22	SLC Domestic Water Supply Ph.3	-	47	47	-
23	All Plants 2009 Pump Upgrades	-	233	-	233
24	UBO & COR Deluge Valves	-	50	-	50
25	All Plants Lighting Upgrade	-	478	113	365
26	LBO, UBO, & COR Sump Oil Alarm Sys U/G	-	128	-	128
27	LBO & UBO Upgrade Spillway Gate Cntrl Ph.1	-	40	-	40
28	UBO & SLC Airwash Tank Rehab	-	108	-	108
29	Queen's Bay Level Gauge Building Ph.1	-	67	-	67
30		20,197	22,060	23,604	18,652
31					
	Transmission Plant				
32	Ellison Distribution Source	12,710	4,480	-	17,190
33	Black Mountain Distribution Source	8,250	6,180	-	14,430
34	Okanagan Transmission Reinforcement	7,191	44,556	51,747	-
35	Benvoulin Distribution Source	500	3,882	4,382	-
36	Big White 138 KV Line & Substation	-	100	-	100
37	Kettle Valley	-	600	-	600
38	Naramata Rehab	3,780	3,468	-	7,248
39	Ooteschenia substation	-	165	-	165
40	Capitalized Inventory & Transformers	6,865	-	6,865	-
41	Recreation Capacity Increase Stage 1,2,3	-	178	178	-
42	Tarry's Capacity Increase	-	403	-	403
43	Kelowna Distribution Capacity Requirements	-	518	518	-
44	30L Conversion - Kaslo	-	556	-	556
45	30L Conversion Slocan / Coffee Creek S/Stns	-	2,350	-	2,350
46	30L Conversion Crawford Bay S/S Mod.	-	1,594	-	1,594
47	Transmission Line Urgent Repairs	-	288	-	288
48	Transmission Right of Way Acquisition	-	311	-	311
49	Transmission Line Pine Beetle Hazard Allocation	-	1,217	-	1,217
50	Transmission ROW Reclamation	-	468	-	468
51	Transmission Line Condition Assessment	-	427	-	427
52	Creston Substation Transformer T1&T2 Circuit Switchers	-	488	-	488
53	Transmission Line Rehabilitation	-	1,639	-	1,639
54	20L Rebuild	-	1,943	-	1,943
55	27L Rebuild	-	648	-	648
56	Station Life /ext & Deficiency/Condition Assessment Program	-	236	-	236
57	Environmental Assessment Program for Substations	-	59	-	59
58	Station Unforseen /Urgent Repairs	-	473	-	473
59	Castlegar Substation Ground Grid Upgrade	-	572	-	572
60	Slocan City - Vahalla	-	2,173	-	2,173
61	LTC Oil Filtration for Summerland T2	-	32	-	32
62	Pine Street Replacement of Distribution Breakers (F-1, F-2, F-3 Breaker Replacement & Protection upgrade)	-	345	-	345
63	Glenmerry DC Supply Upgrade	-	107	-	107
64	Cascade DC Supply Upgrade	-	107	-	107
65	Playmor DC Supply Upgrade	-	111	-	111
66		39,297	80,674	63,690	56,281
67					

Table I - A - 1 (2009) Continued
Additions to Plant in Service
for the Year Ending December 31, 2009

	Distribution Plant				
68	Small Capacity Improvements Unplanned	-	974	-	974
69	New Connects System Wide	-	23,564	-	23,564
70	New Glenmore Feeder	-	788	-	788
71	Christina Lake Feeder-1 Capacity Upgrade	-	608	608	-
72	HOL1 - OKM1 Tie KLO Rd	131	218	-	349
73	VAL1 Feeder Capacity Upgrade	39	858	-	897
74	Distribution Condition Assessment	-	599	-	599
75	Distribution Rehabilitation	-	2,594	-	2,594
76	Distribution Pine beetle Hazard Allocation	-	722	-	722
77	Distribution ROW Reclamation	-	621	-	621
78	Distribution Line Rebuilds	-	1,178	-	1,178
79	Small Planned Capital	-	668	-	668
80	PCB Testing Program - Distribution	-	1,073	-	1,073
81	2008 FortisBC Forced Upgrades	-	1,255	-	1,255
82	Distribution Urgent Repairs	-	1,911	-	1,911
83	Aesthetic & Environmental Upgrades	-	104	-	104
84	Stirrup Replacement Program: #4 Cu Dist	-	254	-	254
85		170	37,989	608	37,550
86					
	General Plant				
87	Distribution Station Automation	-	1,779	-	1,779
88	Protection, Harmonic Remediation, Communications & Rehabilitation	-	864	448	416
89	Vehicles	-	2,000	-	2,000
90	Metering	-	526	-	526
91	Information Systems	-	5,167	-	5,167
92	Telecommunications	-	105	-	105
93	Buildings	-	3,248	-	3,248
94	Furniture & Fixtures	-	347	-	347
95	Tools & Equipment	-	572	-	572
96		-	14,609	448	14,161
97					
98	**TOTAL**	59,664	155,331	88,350	126,644

Table 1 - B (2008)
Deferred Charges and Credits

		Balance at Dec. 31, 2007	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	19,126	2,609	-	(2,108)	19,627
3	Tax Impact	(12,905)	(809)	-	647	(13,067)
4	PLP Energy Management	113	-	-	(77)	36
5		6,334	1,800	-	(1,539)	6,595
6	**Deferred Regulatory Expense**					
7	Provision for True-up for 2006 Incentive	21	-	(21)	-	-
8	Deferred Revenue - Incentive Adjustment	(1,132)	-	1,305	-	173
9	2008 Incentive	-	(1,616)	-	-	(1,616)
10	2005 Revenue Requirements	353	-	-	(176)	176
11	Tax Impact	(101)	-	-	51	(50)
12	2006 Revenue Requirements	107	-	-	(53)	54
13	Tax Impact	(35)	-	-	18	(17)
14	2007 Revenue Requirements	36	-	-	(36)	-
15	Tax Impact	(11)	-	-	11	-
16	2008 Revenue Requirements	32	7	-	-	39
17	Tax Impact	(11)	(2)	-	-	(13)
18	2009 Revenue Requirements	-	100	-	-	100
19	Tax Impact	-	(31)	-	-	(31)
20	2008 COSA & rate design application	44	300	-	-	344
21	Tax Impact	(15)	(93)	-	-	(108)
22	2007 BC Hydro Rate Design	11	-	-	(11)	-
23	Tax Impact	(4)	-	-	4	-
24		(706)	(1,336)	1,284	(193)	(950)
25						
26	**Preliminary and Investigative Charges**	321	1,229	(397)	-	1,153
27						
28	**Other Deferred Charges and Credits**					
29	Trail Office Lease Costs	191	-	-	(12)	179
30	Trail Office Rental to SD#20	(598)	-	(38)	-	(636)
31	Prepaid Pension Costs	6,657	1,912	-	-	8,568
32	Tax Impact	(480)	(593)	-	-	(1,073)
33	Post Retirement Benefits	(3,529)	(2,030)	-	-	(5,559)
34	Tax Impact	1,191	629	-	-	1,821
35	2005 System Development Plan	329	-	-	(165)	164
36	Tax Impact	(16)	-	-	9	(7)
37	2008 System Development Plan Update	248	652	-	-	900
38	Tax Impact	(84)	(202)	-	-	(287)
39	Automated Meter Reading Feasibility Study	68	119	-	-	187
40	Tax Impact	(23)	(37)	-	-	(60)
41	2005 Resource Plan	61	-	-	(30)	31
42	Tax Impact	(7)	-	-	3	(4)
43	2008 Resource Plan Update	217	219	-	-	436
44	Tax Impact	(74)	(68)	-	-	(142)
45	Renew BCH Power Purchase Agreement	4	156	-	-	160
46	Tax Impact	(1)	(48)	-	-	(50)
47	Revenue Protection	176	220	-	(176)	220
48	Tax Impact	(61)	(68)	-	61	(68)
49	Innovative Clean Energy Fund Levy Implementation	23	-	-	(23)	-
50	Tax Impact	(8)	-	-	8	-
51	PLP Potential Substation	25	-	-	(11)	14
52	PLP Settlement Costs	47	-	-	(16)	32
53	PLP Computer Software	109	-	-	(23)	86
54	PLP Deferred Pension Credit	(81)	-	-	12	(70)
55	PLP Deferred Rate Stabilization Account	(75)	-	-	75	-
56	ROW Reclamation (Pine Beetle Kill)	-	2,500	-	-	2,500
57	Tax Impact	-	(775)	-	-	(775)
58	International Financial Reporting Standards	-	125	-	-	125
59	Tax Impact	-	(39)	-	-	(39)
60	2008 City of Penticton - Carmi Substation	-	22	(22)	-	-
61	Tax Impact	-	(7)	7	-	-
62	Right of Way Encroachment Litigation	-	40	-	-	40
63	Tax Impact	-	(12)	-	-	(12)
64	Discount Forfeit Defence (Please refer to note below)	198	-	-	(198)	-
65	Tax Impact	(66)	-	-	66	-
66	2011 Long Term CEP & SDP	-	100	-	-	100
67	Tax Impact	-	(31)	-	-	(31)
68	Joint Pole Use Audit 2008	-	210	-	-	210
69	Tax Impact	-	(65)	-	-	(65)
70		4,440	2,929	(53)	(420)	6,896

Table 1 - B (2008) Continued
Deferred Charges and Credits

		Balance at Dec. 31, 2007	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)		
71	**Deferred Debt Issue Costs**					
72	Series E	7	-	-	(3)	4
73	Series F	129	-	-	(13)	117
74	Series G	118	-	-	(9)	110
75	Series H	106	-	-	(14)	92
76	Series I	199	-	-	(14)	185
77	Series J	131	-	-	(65)	66
78	Series 04-1	1,501	-	-	(215)	1,286
79	Tax Impact	(51)	(20)	-	7	(64)
80	Series 05-1	1,156	-	-	(42)	1,114
81	Tax Impact	(238)	(85)	-	9	(314)
82	Series 07-1	1,241	5	-	(31)	1,215
83	Tax Impact	(85)	(85)	-	2	(167)
84		4,216	(185)	-	(387)	3,644
85						
86	TOTAL DEFERRED CHARGES	14,606	4,437	833	(2,539)	17,337
87	PPA Proceedings		40	-	-	40
88	Tax Impact		(12)	-	-	(12)

Note: 2007 opening Deferred Charges balance has been increased by the Discount Forfeit Defence costs of $132K ($198K before tax).
Reference: Appendix A BCUC Order No. G-147-07, Page 6, Note-1 at Line 83.
Current BC Hydro PPA Proceeding costs have been seperated and being collected in a non-rate based, non-interest bearing deferral account as per the NSA of November 2008 for Revenue Requirements 2009 (Refer Row 87 & 88)

Table 1 - B (2009)
Deferred Charges and Credits

		Balance at Dec. 31, 2008	Additions and Transfers Transfers	Amortized to Other Accounts Other Accounts	Amortization Amortization	Balance at Dec. 31, 2009
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	19,627	3,668	-	(2,689)	20,606
3	Tax Impact	(13,067)	(1,100)	-	1,790	(12,377)
4	PLP Energy Management	36	-	-	(36)	-
5		6,595	2,568	-	(934)	8,229
6	**Deferred Regulatory Expense**	-				-
7	Deferred Revenue - Incentive Adjustment	173	-	(173)	-	-
8	2008 Incentive	(1,616)	-	1,616	-	-
9	2005 Revenue Requirements	176	-	-	(176)	-
10	Tax Impact	(50)	-	-	50	-
11	2006 Revenue Requirements	54	-	-	(54)	-
12	Tax Impact	(17)	-	-	17	-
13	2008 Revenue Requirements	39	-	-	(39)	-
14	Tax Impact	(13)	-	-	13	-
15	2009 Revenue Requirements	100	-	-	-	100
16	Tax Impact	(31)	-	-	-	(31)
17	2010 Revenue Requirements	-	105	-	-	105
18	Tax Impact	-	(32)	-	-	(32)
19	2008 COSA & rate design application	344	300	-	-	644
20	Tax Impact	(108)	(90)	-	-	(198)
21	Interim BC Hydro Rate Adjustment per NSA 2008	-	2,224	-	-	2,224
22	Tax Impact	-	(667)	-	-	(667)
23		(950)	1,840	1,443	(188)	2,145
24						
25	**Preliminary and Investigative Charges**	1,153	2,763	(765)	-	3,151
26		-				
27	**Other Deferred Charges and Credits**	-				
28	Trail Office Lease Costs	179	-	-	(12)	167
29	Trail Office Rental to SD#20	(636)	-	(44)	-	(679)
30	Prepaid Pension Costs	8,568	287	-	-	8,855
31	Tax Impact	(1,073)	(86)	-	-	(1,159)
32	Post Retirement Benefits	(5,559)	(2,030)	-	-	(7,589)
33	Tax Impact	1,821	609	-	-	2,430
34	2005 System Development Plan	164	-	-	(164)	-
35	Tax Impact	(7)	-	-	7	-
36	2008 System Development Plan Update	900	-	-	(450)	450
37	Tax Impact	(287)	-	-	143	(143)
1	Automated Meter Reading Feasibility Study	187	-	-	-	187
2	Tax Impact	(60)	-	-	-	(60)
38	2005 Resource Plan	31	-	-	(31)	-
39	Tax Impact	(4)	-	-	4	-
40	2008 Resource Plan Update	436	-	-	(87)	349
41	Tax Impact	(142)	-	-	28	(114)
42	Renew BCH Power Purchase Agreement	160	-	-	(32)	128
43	Tax Impact	(50)	-	-	10	(40)
44	Revenue Protection	220	225	-	(220)	225
45	Tax Impact	(68)	(68)	-	68	(68)
46	PLP Potential Substation	14	-	-	(14)	-
47	PLP Settlement Costs	32	-	-	(16)	16
48	PLP Computer Software	86	-	-	(23)	63
49	PLP Deferred Pension Credit	(70)	-	-	12	(58)
50	ROW Reclamation (Pine Beetle Kill)	2,500		-	(250)	2,250
51	Tax Impact	(775)	-	-	78	(698)
52	International Financial Reporting Standards	125	280	-	(125)	280
53	Tax Impact	(39)	(84)	-	39	(84)
54	2008 City of Penticton - Carmi Substation	-	-	-	-	-
55	Tax Impact	-	-	-	-	-
56	Right of Way Encroachment Litigation	40	40	-	-	80
57	Tax Impact	(12)	(12)	-	-	(24)
58	2011 Long Term CEP & SDP	100	700	-	-	800
59	Tax Impact	(31)	(210)	-	-	(241)
60	DSM Study	-	100	-	-	100
61	Tax Impact	-	(30)	-	-	(30)
62	Joint Pole Use Audit 2008	210		-	(42)	168
63	Tax Impact	(65)		-	13	(52)
64		6,896	(279)	(44)	(1,064)	5,509

Table 1 - B (2009) Continued
Deferred Charges and Credits

			Additions and	Amortized to		
		Balance at	Transfers	Other Accounts	Amortization	Balance at
		Dec. 31, 2008	Transfers	Other Accounts	Amortization	Dec. 31, 2009
				($000s)		
65	**Deferred Debt Issue Costs**	-				
66	Series E	4	-	-	(4)	-
67	Series F	117	-	-	(13)	104
68	Series G	110	-	-	(9)	101
69	Series H	92	-	-	(14)	78
70	Series I	185	-	-	(14)	171
71	Series J	66	-	-	(66)	-
72	Series 04-1	1,286	-	-	(215)	1,071
73	Tax Impact	(64)	-	-	8	(56)
74	Series 05-1	1,114	-	-	(42)	1,072
75	Tax Impact	(314)	(85)	-	12	(387)
76	Series 07-1	1,215	-	-	(31)	1,184
77	Tax Impact	(167)	(85)	-	5	(247)
78	Series 09	-	1,580	-	-	1,580
79	Tax Impact	-	(95)	-	-	(95)
80		3,644	1,315	-	(382)	4,577
81						
82	TOTAL DEFERRED CHARGES	17,337	8,207	635	(2,569)	23,611
83	PPA Proceedings	40	-	-		40
84	Tax Impact	(12)	-	-		(12)

Note: Current BC Hydro PPA Proceeding costs have been seperated and being collected in a non-rate based, non-interest bearing deferral account as per the NSA of November 2008 for Revenue Requirements 2009 (Refer Row 83 & 84)

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Accumulated Provision for Depreciation and Amortization
For the Year Ending December 31, 2008

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2007	Deprec. Rate	Asset Balance Dec. 31, 2007	Depreciation Expense Dec. 31, 2008	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2008
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(467)	2.6%	847	22	-	(445)
2	331	Structures and Improvements	4,571	1.2%	10,947	131	(180)	4,522
3	332	Reservoirs, Dams and Waterways	2,812	1.7%	19,433	331	(409)	2,734
4	333	Water Wheels, Turbines & Generators	3,279	2.2%	54,503	1,203	(516)	3,967
5	334	Accessory Electrical Equipment	7,253	2.4%	22,370	539	(156)	7,635
6	335	Other Power Plant Equipment	6,338	2.3%	38,277	883	(48)	7,173
7	336	Roads, Railroads, and Bridges	201	1.4%	1,053	~~15~~	~~-~~	~~216~~
8			23,987	2.1%	147,430	3,125	(1,310)	25,802
9		Transmission Plant	-					-
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	-	(72)
11	350.1	Land Rights - Clearing	951	1.6%	4,496	72	-	1,023
12	353	Station Equipment	22,435	3.0%	135,378	4,075	(3,249)	23,261
13	355	Poles Towers & Fixtures	14,089	3.0%	65,142	1,961	(1,374)	14,676
14	356	Conductors and Devices	10,555	3.0%	62,601	1,884	(1,590)	10,849
15	359	Roads and Trails	9	2.9%	817	24	-	33
16			47,967	2.9%	275,513	8,016	(6,213)	49,770
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	1,736	-	-	-
19	360.1	Land Rights - Clearing	279	2.1%	5,856	123	-	403
20	362	Station Equipment	26,565	3.0%	115,295	3,471	(54)	29,982
21	364	Poles Towers & Fixtures	30,187	3.0%	105,392	3,173	(352)	33,009
22	365	Conductors and Devices	42,493	3.0%	175,985	5,297	(415)	47,375
23	368	Line Transformers	16,698	2.9%	83,699	2,435	(198)	18,935
24	369	Services	6,403	0.0%	7,292	-	-	6,403
25	370	Meters	4,545	3.5%	12,754	448	(21)	4,972
26	371	Installation on Customers' Premises	985	0.0%	938	-	(125)	860
27	373	Street Lighting and Signal Systems	1,471	2.4%	7,318	177	-	1,648
28			129,628	2.9%	516,264	15,124	(1,165)	143,586
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	-	(11)
31	390	Structures - Frame & Iron	528	0.8%	337	3	-	531
32	390.1	Structures - Masonry	2,474	3.0%	20,398	614	-	3,088
33	391	Office Furniture & Equipment	3,155	7.5%	5,233	394	-	3,550
34	391.1	Computer Equipment	25,810	10.6%	42,179	4,486	-	30,297
35	392	Transportation Equipment	4,036	0.4%	16,447	66	-	4,103
36	394	Tools and Work Equipment	4,668	9.5%	9,884	942	-	5,611
37	397	Communication Structures and Equipment	4,781	6.0%	20,016	1,205	(482)	5,504
38			45,442	6.4%	120,295	7,711	(482)	52,671
39								
40	108	Total Accumulated Depreciation	247,024	3.2%	1,059,502	33,976	(9,170)	271,830
41								
42		Deduct - Portion of CIAC Depreciated				(3,305)		
43								
44	403	Depreciation Expense				30,671		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,466		11,912	186		4,652
48	390	Leasehold Improvements	1,238		2,568	308		1,546
49		Rate Stabilization Adjustment	(2,487)	10.0%		311		(2,176)
50		Manual entry for buy out of lease	82					82
51		Total Accumulated Amortization	3,299			805		4,104
52								
53		Accumulated Amortization per						
54		Balance Sheet	250,323			31,476		275,935

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Table I - C (2009)
Accumulated Provision for Depreciation and Amortization
For the Year Ending December 31, 2009

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2008	Deprec. Rate	Asset Balance Dec. 31, 2008	Depreciation Expense Dec. 31, 2009	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2009
						(000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(445)	2.6%	847	22	-	(423)
2	331	Structures and Improvements	4,522	1.2%	11,403	137	(258)	4,402
3	332	Reservoirs, Dams and Waterways	2,734	1.7%	21,193	360	(348)	2,746
4	333	Water Wheels, Turbines & Generators	3,967	2.2%	56,908	1,252	(1,001)	4,217
5	334	Accessory Electrical Equipment	7,635	2.4%	23,245	558	(78)	8,115
6	335	Other Power Plant Equipment	7,173	2.3%	38,547	887	(75)	7,986
7	336	Roads, Railroads, and Bridges	216	1.4%	1,053	15	-	231
8			25,802	2.1%	153,195	3,231	(1,760)	27,273
9		Transmission Plant	-					-
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	-	(72)
11	350.1	Land Rights - Clearing	1,023	1.6%	4,496	72	-	1,095
12	353	Station Equipment	23,261	3.0%	168,913	5,067	(4,290)	24,038
13	355	Poles Towers & Fixtures	14,676	3.0%	73,975	2,219	(2,066)	14,830
14	356	Conductors and Devices	10,849	3.0%	71,198	2,136	(2,017)	10,968
15	359	Roads and Trails	33	2.9%	817	24	(19)	38
16			49,770	2.9%	326,477	9,518	(8,392)	50,897
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	2,986	-	-	-
19	360.1	Land Rights - Clearing	403	2.1%	7,106	149	-	552
20	362	Station Equipment	29,982	3.0%	117,123	3,514	-	33,496
21	364	Poles Towers & Fixtures	33,009	3.0%	114,430	3,433	(138)	36,304
22	365	Conductors and Devices	47,375	3.0%	187,140	5,614	(113)	52,876
23	368	Line Transformers	18,935	2.9%	90,341	2,620	(46)	21,510
24	369	Services	6,403	0.0%	7,292	-	-	6,403
25	370	Meters	4,972	3.5%	13,455	471	(7)	5,436
26	371	Installation on Customers' Premises	860	0.0%	5,145	-	(34)	826
27	373	Street Lighting and Signal Systems	1,648	2.4%	7,318	176	-	1,824
28			143,586	2.9%	552,334	15,977	(337)	159,226
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	-	(11)
31	390	Structures - Frame & Iron	531	0.8%	337	3	-	534
32	390.1	Structures - Masonry	3,088	3.0%	21,742	652	(23)	3,717
33	391	Office Furniture & Equipment	3,550	7.5%	5,767	433	(21)	3,962
34	391.1	Computer Equipment	30,297	10.6%	51,652	5,475	(63)	35,709
35	392	Transportation Equipment	4,103	0.4%	19,180	77	(23)	4,157
36	394	Tools and Work Equipment	5,611	9.5%	10,664	1,013	(7)	6,617
37	397	Communication Structures and Equipment	5,504	6.0%	23,031	1,382	(457)	6,429
38			52,671	6.5%	138,174	9,035	(593)	61,113
39								
40	108	Total Accumulated Depreciation	271,830	3.2%	1,170,181	37,761	(11,081)	298,510
41								
42		Deduct - Portion of CIAC Depreciated	-			(3,675)		
43								
44	403	Depreciation Expense				34,086		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,652		11,912	186		4,838
48	390	Leasehold Improvements	1,546		2,932	352		1,898
49		Rate Stabilization Adjustment	(2,176)	10.0%		311		(1,865)
50		Manual entry for buy out of lease	82					82
51		Total Accumulated Amortization	4,104			849		4,953
52								
53		Accumulated Amortization per						
54		Balance Sheet	275,935			34,935		303,463

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

	Actual	Forecast		Forecast	
	Dec. 31 2007	2008 Additions	Dec. 31 2008	2009 Additions	Dec. 31 2009
		($000s)			
1 Gross Book Value	110,154	12,342	122,496	13,776	136,272
2 Accumulated Depreciation	(31,804)	(3,305)	(35,109)	(3,675)	(38,784)
3 Net Book Value	78,351		87,388		97,489

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Table I - E (2009)
Allowance for Working Capital

Line	Lag Days Calculation	Lag (Lead) Days	2009 Forecast ($000)	2009 Extended ($M)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	50.1	233,081	11,677	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	2,304	61	
5	Contract Revenue	44.3	1,576	70	
6	Miscellaneous Revenue	31.8	704	22	
7	Investment Income	15.0	331	5	
8			**$ 237,996**	**$ 11,836**	**49.7**
9					
10	**Expenses**				
11	Power Purchases	42.2	69,448	2,930	
12	Wheeling	40.2	4,010	161	
13	Water Fees	(1.0)	8,286	(8)	
14	*Operating Labour:*			0	
15	Salaries & Wages	5.3	14,746	78	
16	Employee Benefits	13.2	10,691	141	
17	Contracted Manpower	50.6	4,756	241	
18	Property Tax	2.6	11,561	30	
19	Rental of T&D Facilities	47.8	3,220	154	
20	Office Lease - Kelowna	(15.2)	222	(3)	
21	Office Lease - Trail	91.3	1,212	111	
22	Materials	45.6	834	38	
23	Insurance	(182.5)	1,578	(288)	
24	Income Tax	15.2	4,354	66	
25	Interest	82.9	34,803	2,885	
26			**$ 169,721**	**$ 6,536**	**38.5**
27					
28	**Net Lag/(Lead) Days**				**11.2**
29					
30					
31	**Forecast Working Capital Allowance**				
32					
33	**Lead-Lag Study Allowance**				$ 5,218
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			5,000	
38	Employee Loans			400	
39	Uncollectable Accounts			700	
40	Inventory (forecast monthly average investment)			700	
41					$ 6,800
42	**Less Funds Available:**				
43	Customer Deposits			3,300	
44	Employee Payroll Deductions			300	
45	Provincial Services Tax			800	
46	Goods and Services Tax			600	
47					$ 5,000
48					
49	**2009 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**$ 7,018**

Table 1 - F (2009)
Adjustment for Capital Additions, 2009

		Plant In Service ($000s)	Months in Rate Base	Weighted Value
1	January	17,611	11.5	16,877
2	February	17,611	10.5	15,409
3	March	17,611	9.5	13,942
4	April	6,161	8.5	4,364
5	May	6,161	7.5	3,851
6	June	6,161	6.5	3,337
7	July	5,756	5.5	2,638
8	August	5,756	4.5	2,159
9	September	5,756	3.5	1,679
10	October	8,095	2.5	1,686
11	November	8,095	1.5	1,012
12	December	8,095	0.5	337
13	Total	112,868		67,291
14	Less Simple Average			56,434
15	Adjustment to Rate Base			10,857

16 * Expenditures are reduced by Contributions in Aid of Construction

SCHEDULE 2
EARNED RETURN

		Actual 2007	Forecast 2008	Forecast 2009
1	SALES VOLUME (GWh)	3,090	3,064	3,107
2			($000s)	
3	ELECTRICITY SALES REVENUE	209,651	219,027	233,081
4				
5	EXPENSES			
6	Power Purchases	66,629	64,629	69,448
7	Water Fees	7,918	7,863	8,286
8	Wheeling	3,471	3,624	4,010
9	Net O&M Expense	34,165	35,813	37,258
10	Property Tax	10,642	11,023	11,561
11	Depreciation and Amortization	30,949	34,015	37,504
12	Other Income	(5,504)	(5,093)	(4,915)
13	Incentive Adjustments	(1,391)	332	(1,443)
14	UTILITY INCOME BEFORE TAX	62,771	66,821	71,372
15	Less:			
16	INCOME TAXES	5,898	5,551	4,354
17				
18	EARNED RETURN	56,873	61,270	67,018
19	RETURN ON RATE BASE			
20	Utility Rate Base	746,543	802,807	907,977
21	Return on Rate Base	7.62%	7.63%	7.38%

Table 2 - A - 1
Energy Sales by Customer Class

		Actual 2007	Forecast 2008	Forecast 2009
			(GWh)	
1	Residential	1,160	1,212	1,222
2	General Service	636	659	678
3	Industrial	352	225	224
4	Wholesale	881	906	921
5	Lighting	13	14	14
6	Irrigation	49	48	48
7	Total Sales	3,090	3,064	3,107
8	City of Nelson Adjustment for Losses			(2)
9	Losses and Company Use	320	301	296
10	Gross Load	3,410	3,365	3,401

Table 2 - A - 2
Sales Revenue by Customer Class

		Actual 2007	Forecast 2008	Forecast * 2009
			($000s)	
11	Residential	93,100	100,400	100,413
12	General Service	50,100	53,320	56,978
13	Industrial	19,170	15,003	13,233
14	Wholesale	43,381	45,885	46,518
15	Lighting and Irrigation	3,900	4,419	5,706
17	Total	209,651	219,027	222,847
18	* Forecast at 2008 approved rates			

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

		Actual 2007	Forecast 2008	Forecast 2009
19	Residential	93,647	95,504	97,255
20	General Service	11,010	11,349	11,583
21	Wholesale	7	7	7
22	Industrial	38	37	37
23	Lighting & Irrigation	3,022	3,031	3,031
24	Total	107,724	109,928	111,913

Table 2 - B
Power Purchase Expense

		Actual 2007	Forecast 2008	Forecast 2009
			(GWh)	
1	FortisBC	1,498	1,580	1,581
2	DSM	-	4	25
3	Power Purchases (net of surplus sales)	1,912	1,785	1,820
4	Total System Load (before DSM savings)	3,410	3,369	3,426
5	Less DSM	-	(4)	(25)
6	Total System Load (including DSM savings)	3,410	3,365	3,401
			($000s)	
7	Expense - Energy	56,414	53,250	56,576
8	Expense - Capacity	12,219	12,418	13,173
9	Upgrade Life Extension credits and other adjustments	(2,004)	(1,039)	(301)
10	Total Power Purchase Expense	66,629	64,629	69,448

Table 2 - C
Operating and Maintenance Expense

		Approved 2008	Forecast 2009
1	O&M, Formula-Driven		
2	Base O&M Cost per Customer	$ 382.48	$ 382.48
3	Consumer Price Index (British Columbia)	2.0%	2.1%
4	Productivity Improvement Factor	-2.0%	-3.0%
5	O&M per Customer, Escalated	$ 382.48	$ 379.04
6			
7	Average Number of Customers (Line 22)	109,334	110,920
8			
9		($000s)	
10	Base O&M (Line 5 times Line 7)	41,818	42,043
11			
12	Pension and Post-Retirement Benefits (Note 1)	2,739	3,318
13	Trail Office Lease (Note 1)	753	1,212
14	Total Operating and Maintenance Expense for Base O&M	45,310	46,573
15			
16	Capitalized Overhead	(9,062)	(9,315)
17	Net Operating & Maintenance Expense	36,248	37,258
18			
19	Number of Customers		
20	Opening Count (Note 2)	107,905	109,928
21	Ending Count	110,763	111,913
22	Average Number of Customers	109,334	110,920

Note 1: Base O&M

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.

Note 2: Number of Customers

The Opening Count of Customers for 2008 has been restated to reflect the addition of 3,212 PLP Customers and a true up of actual 2007 customer additions.

Table 2 - D
Wheeling

		Actual 2007	Forecast 2008	Forecast 2009
1	**Wheeling Nomination**		(MW)	
2	Vernon/Okanagan	1,920	1,965	2,115
3	Creston	396	402	420
4	**Expense**		($000s)	
5	Vernon/Okanagan	3,055	3189	3529
6	Creston	410	425	457
7	Other	6	10	24
8	Total Wheeling Expense	3,471	3,624	4,010

Table 2 - E
Property Tax Expense

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
1	Generating Plant	2,649	2,459	2,557
2	Transmission and Distribution	4,893	5,209	5,434
3	Substation Equipment	2,588	2,842	3,021
4	Land and Buildings	512	513	549
5	Total Property Tax	10,642	11,023	11,561

Table 2 - F
Water Fees

		Actual 2007	Forecast 2008	Forecast 2009
1	Plant Entitlement Use (GWh) in previous year	1,509	1,498	1,580
2	Water Fees ($000s)	7,918	7,863	8,286

Table 2 - G
Other Income

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
1	Apparatus and Facilities Rental			
2	Electric Apparatus Rental	1,724	2,283	2,133
3	Lease Revenue	146	168	171
4		1,870	2,451	2,304
5	Contract Revenue			
6	Waneta Management Fee	319	343	238
7	Waneta Management Fee Capital	432	175	138
8	Waneta Carrying Costs	94	95	94
9				
10	Brilliant Management Fee (including BTS)	181	147	166
11	Brilliant Management Fee Capital	238	319	299
12				
13	Fortis Pacific Holdings Inc.	660	543	641
14		1,924	1,622	1,576
15	Miscellaneous Revenue			
16	Connection Charges	527	520	545
17	NSF Cheque Charges	9	9	9
18	Sundry Revenue	206	171	150
19		742	700	704
20				
21	Investment Income	968	320	331
22				
23	Total	5,504	5,093	4,915

Table 2 - H - 1
2008 Flow Through Adjustments

	Approved	Forecast	Variance	Income Tax Shield ($000s)	After Tax Amount	Customer Share	Flow Through Adjustment
1 2007 Incentive True Up	1,284	1,111	173	-	173	100%	173
2 Interest Expense	31,789	30,400	(1,389)	(431)	(958)	1	(958)
3 Pension Expense	2,739	2,539	(200)	(62)	(138)	1	(138)
4 BC Tax Rate Reduction	-	-	-	60	(60)	1	(60)
5 Pope & Talbot Bad Debt	-	565	565	175	390	1	390
6 Net variance from forecast (Canpar / Pope / Weyerhaeuser)	1,291	811	480	149	331	1	331
7 Flow Through Adjustment							(435)

Table 2 - H - 2
2008 ROE Incentive Adjustment

	Approved	**Forecast**	**Variance ($000s)**	**Customer Share**	**ROE Incentive Adjustment**
8 Net Income for ROE Incentive	29,687	32,049	2,362	50%	(1,181)
9 Common Equity	329,139	321,123			
10 Allowed ROE	9.02%	9.98%	0.96%	50.00%	0.48%

SCHEDULE 3
INCOME TAX EXPENSE

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
1	UTILITY INCOME BEFORE TAX	62,771	66,821	71,372
2	Deduct:			
3	Interest on Non Rate Base Deferral Account		-	-
4	Interest Expense	28,731	30,400	34,803
5				
6	ACCOUNTING INCOME	34,040	36,421	36,569
7				
8	Adjustments to Accounting Income			
9	to arrive at Taxable Income			
10				
11	Deductions			
12	Capital Cost Allowance	37,586	43,252	48,149
13	Capitalized Overhead	8,836	9,062	9,315
14	Additions to Deferred Charges for Tax Purposes			
15				
16	Incentive & Revenue Deferrals	1,391	(332)	1,443
17	Financing Fees	921	933	1034
18	All Other (net effect)	(409)	509	501
19		48,325	53,424	60,442
20				
21	Additions			
22	Amortization of Deferred Charges	2,807	2,539	2,569
23	Depreciation	28,142	31,476	34,935
24		30,949	34,015	37,504
25				
26	TAXABLE INCOME	16,664	17,012	13,631
27				
28	Tax Rate	34.1%	31.0%	30.0%
29				
30	Taxes Payable	5,686	5,274	4,089
31	Prior Years' Overprovisions/(Underprovisions)	31	87	-
32	Deferred Charges Tax Effect	181	190	265
33				
34	REGULATORY TAX PROVISION	5,898	5,551	4,354

APPENDIX A
to Order G-193-08
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Table 3 - A (2009)
Calculation of Capital Cost Allowance

Line	Class	2008 Closing UCC	2009 Adds	Half-Year Rule	CCA Rate	2009 CCA	2009 Closing UCC
				($000s)			
1	**1A**	269,270	2,195	1,097	4%	10,815	260,650
2	**1B**	1,521	3,248	1,624	6%	189	4,579
3	**17**	76,278	15,751	7,875	8%	6,732	85,297
4	**2**	27,117	-	-	6%	1,627	25,490
5	**3**	1,552	-	-	5%	78	1,474
6	**6**	12	-	-	10%	1	11
7	**8**	4,919	1,446	723	20%	1,128	5,236
8	**10**	13,954	5,675	2,837	30%	5,037	14,591
9	**12**	1,028	1,098	549	100%	1,577	548
10	**13**	1,732	-	-	est	67	1,665
11	**42**	4,723	-	-	12%	567	4,156
12	**45**	2,015	-	-	45%	907	1,108
13	**47**	203,735	69,697	34,848	0.08	19,087	254,345
13	**50**	362	500	250	0.55	337	525
14							
15		608,217	99,608	49,804		48,149	659,676
16							
17							
18	Land		**2,939**				
19	Net Salvage		**(4,187)**				
20	AFUDC		**5,193**				
21	Capitalized overhead		**9,315**				
22	CIAC		**13,776**				
23	Plant in service		**126,644**				
24							

SCHEDULE 4
ACTUAL AND FORECAST COMMON SHARE EQUITY

			Actual 2007	Forecast 2008	Forecast 2009
				($000s)	
1	Share Capital		148,000	163,000	183,000
2	Retained Earnings		161,207	159,672	177,140
3					
4	COMMON EQUITY - OPENING BALANCE		309,207	322,672	360,140
5					
6	Less:	Common Dividends	(11,800)	(13,400)	(14,500)
7					
8	Add:	Net Income	28,143	30,868	32,215
		Share Adjustment	(17,878)	-	
9		Shares Issued	15,000	20,000	30,000
10					
11	COMMON EQUITY - CLOSING BALANCE		322,672	360,140	407,855
12					
13	SIMPLE AVERAGE		315,940	341,406	383,998
14					
15	Adjustment for Shares Issued		(4,884)	(7,370)	(3,658)
16	Deemed Equity Adjustment		(6,216)	(12,913)	(17,149)
17					
18	COMMON EQUITY - AVERAGE		304,840	321,123	363,191

Table 4 - A
Calculation of Adjustment for Shares Issued

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
19	Opening Balance	148,000	163,000	183,000
20	Adjustment to Opening Balance			
21	Shares Issued #1	10,000	10,000	15,000
22	Issue Date	Sept 28	Sep 29	June 30
23				
24	Shares Issued #2	5,000	10,000	15,000
25	Issue Date	Dec 28	Dec 28	Sep 30
26				
27	Opening Balance x Days in Effect /365	148,000	163,000	183,000
28	Share Adjustment			
29	Issue #1 times Days in Effect / 365	2,575	2,548	7,562
30	Issue #2 times Days in Effect / 365	41	82	3,781
31		150,616	165,630	194,342
32	less: Simple Average	(155,500)	(173,000)	(198,000)
33	Adjustment for Shares Issued	(4,884)	(7,370)	(3,658)

SCHEDULE 5
ACTUAL AND FORECAST RETURN ON CAPITAL

		Actual 2007	Forecast 2008	Forecast 2009
			($000s)	
1	Secured and Senior Unsecured Debt	433,691	489,468	539,974
2	Proportion	57.45%	60.97%	59.47%
3	Embedded Cost	6.50%	6.36%	6.32%
4	Cost Component	3.74%	3.88%	3.76%
5	Return	28,202	31,126	34,112
6				
7	Short Term Debt	16,329	(7,784)	4,812
8	Proportion	2.16%	-0.97%	0.53%
9	Embedded Cost	3.24%	9.33%	14.36%
10	Cost Component	0.07%	-0.09%	0.08%
11	Return (including fees)	529	(726)	691
12				
13				
14	Common Equity	304,840	321,123	363,191
15	Proportion	40.38%	40.00%	40.00%
16	Embedded Cost	9.23%	9.61%	8.87%
17	Cost Component	3.73%	3.85%	3.55%
18	Return	28,143	30,868	32,215
19				
20	TOTAL CAPITALIZATION	754,860	802,807	907,977
21	RATE BASE	746,543	802,807	907,977
22				
23	Earned Return	56,873	61,268	67,018
24				
25	RETURN ON CAPITAL	7.53%	7.63%	7.38%
26	RETURN ON RATE BASE	7.62%	7.63%	7.38%