FORTISBC

Preliminary 2010 Revenue Requirements

Tab 2

Executive Summary

2.0 Introduction

In 2006, FortisBC negotiated a settlement agreement (the “2006 NSA”) that included a form of Performance Based Regulation (“PBR”) for setting rates in 2007 and 2008 with an option to extend the agreement for 2009 upon agreement by the Parties. The 2006 NSA was approved by the British Columbia Utilities Commission (“the Commission” or “BCUC”) by Order No. G-58-06.

In 2008, the Company and its stakeholders negotiated an extension of the PBR Plan for a term ending December 31, 2011; the Negotiated Settlement Agreement concerning FortisBC’s 2009 Revenue Requirements and the PBR extension (the “2009 NSA”) was approved by Commission Order G-193-08.

The 2009 NSA includes a Productivity Improvement Factor (“PIF”) of 1.5 percent for 2010.

2.1 Rate Drivers

The Company is requesting a rate increase of 4.6 percent effective January 1, 2010. The primary components of the requested rate increase are as follows:

- **Power Supply:** increase of $6.9 million in Revenue Requirements or 2.0 percent;
- **Operating:** increase of $1.2 million in Revenue Requirements or 0.4 percent;
- **Taxes:** increase of $0.4 million in Revenue Requirements or 0.1 percent;
- **Financing:** increase of $8.5 million in Revenue Requirements or 2.4 percent; and
- **Incentive and Other Adjustments:** reduced Revenue Requirements by $0.9 million or a rate decrease of 0.3 percent.

Each component of the required increase is discussed in more detail in Tab 3. A full set of financial schedules supporting the Revenue Requirements calculations can be found in Tab 4. The forecasts in this Preliminary Revenue Requirements are based on financial results to July 31, 2009. On or before November 2, 2009, FortisBC will file updates to the 2009 and 2010 forecasts incorporating actual results to September 30, 2009.

2.2 Capital Plan

FortisBC's long-term capital program for its Transmission, Stations, Distribution, and Telecommunications facilities was documented in the 2005-2024 System Development Plan ("SDP") which was filed with the Commission in 2005. The SDP was most recently reviewed and updated in conjunction with the Company's 2009-2010 Capital Expenditure Plan (the "2009/10 Capital Plan") which was filed on June 27, 2008 and which also outlines expenditures for other plant including Generation, Demand Side Management ("DSM") and General Plant.

FortisBC received approval under Commission Order G-11-09 for the 2009/10 Capital Plan on February 27, 2009, subject to certain determinations and directions included in the accompanying decision. The 2009/10 Capital Plan is focused on safety, customer service, reliability, productivity, and the environment. The projects associated with these expenditures support the BC government's energy objectives as defined in Section 1 of the Utilities Commission Act and policy actions as outlined in the 2007 BC Energy Plan. Capital expenditures for 2009 and 2010, net of customer contributions, are forecast to be $110.0 million and $157.1 million respectively and are described in Tab 7.

FortisBC intends to file a long term Integrated System Plan in 2010 which will include the 2011-2030 System Development Plan for Transmission, Stations, Distribution and Telecommunications, and Generation Facilities. In addition, the Integrated System Plan will take into account FortisBC's long term Resource Plan, which was filed on May 27, 2009, the regulatory review of which is expected to be completed in early 2010, and its long term Demand Side Management Plan, presently under development, as well as General Plant expenditures.

For informational purposes as required under the terms of the PBR, the Company has tabulated operational savings claimed as a result of its Capital Plan and Certificate of

Public Convenience and Necessity ("CPCN") applications and has included this information material in Appendix D of this application.

2.3 Load and Customer Forecast

Gross system energy load is anticipated to grow to 3,482 Gigawatt hours ("GWh") which is 2.8 percent above the Company's current 2009 weather-normalized forecast. The total number of customer accounts are projected to increase to 112,911 which is 1.5 percent above the current 2009 forecast. Further details on these projections can be found in Tab 5.

2.4 Power Supply

Power Purchase costs for 2010 are forecast to increase to $77.2 million from the $70.2 million currently forecast for 2009. The increase is primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement ("PPA"), and BC Hydro and Brilliant Plant rate increases, partially offset by reduced market requirements. Further details can be found in Tab 6.

Power purchase expense as outlined in Tab 6 is based on firm BC Hydro rates to March 31, 2010, as approved by Order G-16-09. The Company has not included any forecast of future BC Hydro rate increases in its Power Purchase Expense forecasts and, as in previous years, proposes to flow through any changes in BC Hydro rates during 2010.

2.5 Gross Operating and Maintenance Costs ("O&M") and Capitalized Overhead

FortisBC establishes its O&M costs and capitalized overheads by formula during the PBR term. For 2010, the formula incorporates a Productivity Improvement Factor ("PIF") of 1.5 percent, reducing Base O&M by $0.64 million as presented in Table 3.2.1 of Tab 3.

2.6 Other Costs and Income

All other cost accounts including wheeling, interest, property taxes, income taxes, depreciation and amortization have been forecast for 2010 as discussed in Tab 3.

2.7 Financing

On May 7, 2009, the Commission Order G-51-09 granted approval for FortisBC to issue up to $300 million Medium Term Note ("MTN") Debentures, pursuant to a Shelf Prospectus, from time to time until June 11, 2011. The Company expects to issue $100 million of MTN Debentures during 2010 in order to pay down its operating credit facility, which has been used to finance its capital expenditure program. FortisBC also expects to issue, subject to Commission approval, an additional $30 million of Common Share Equity in 2010 in order to maintain its capital structure of 60 percent debt and 40 percent equity.

The 2010 Return on Equity (“ROE”) in this Application has been forecast in accordance with the BCUC Automatic Adjustment Mechanism. Based on the August Consensus Economics forecast the 2010 return equity is forecast to be 8.78 percent including FortisBC’s risk premium of 40 basis points. Final ROE under the Automatic Adjustment Mechanism will be based on the November Consensus Economics forecast. FortisBC notes that the Terasen Utilities’ application of May 15, 2009 requests that the Commission eliminate the use of an ROE automatic adjustment mechanism in the determination of the ROE for the Terasen Utilities, and that an Oral Hearing into this application is in progress as of the filing date of this Preliminary Revenue Requirements Application. The outcome of the Terasen Utilities’ application will impact FortisBC’s allowed ROE because Terasen Gas Inc. is the benchmark low-risk utility for purposes of applying FortisBC’s risk premium.

Any impact of a Commission decision concerning the Terasen Utilities’ application, if issued prior to the final determination of FortisBC’s 2010 Revenue Requirements, will be incorporated at that time. FortisBC expects that any changes to ROE arising subsequent to the setting of final 2010 rates would be flowed through to rates at the time of the decision.

Further detail on the Company’s financing can be found in Tab 3.

2.8 Flow-through Adjustments

There are a number of flow-through adjustments that are forecast to decrease Revenue Requirements by $0.9 million (after tax) in 2010. The flow-through adjustments are detailed in Tab 3, section 3.5.

2.9 ROE Sharing Mechanism

The Incentive Mechanism applicable to the current PBR term provides for equal sharing, after the flow-through adjustments noted above, of any variance above or below the approved rate.

The 2009 forecast of net income for incentive calculation purposes, shown on Table 3.6.1 in Tab 3, is $34.4 million which is $2.2 million higher than the approved net income for 2009. This falls within the 2 percent band subject to sharing and results in a customer share of $1.1 million. The true-up of the 2008 incentive reduces 2010 Revenue Requirements by a further $0.3 million.

2.10 Deferred Costs

These costs are described in Tab 3 under section 3.7.2 and include Demand Side Management, Preliminary and Investigative Charges, Deferred Regulatory Expense including Incentive Adjustments, and Other Deferred Charges and Credits. Pursuant to Order G-52-05, deferred charges are recorded net of income tax. Incentive Adjustments do not impact Income Tax Expense and are therefore not recorded net of tax. Similarly, Preliminary and Investigative Charges are either charged to capital or expensed and do not impact Income Tax, therefore they are not recorded net of tax. Pursuant to Order G-147-07, the Company has included a report on the activities associated with its deferred Revenue Protection costs in Tab 3 as well.

2.11 Performance Standards

Performance Standards for the PBR term were agreed to as part of the 2006 NSA and approved by Commission Order No. G-58-06. These Performance Standards are meant to enable an overall assessment of the Company's performance for the purpose of determining its eligibility for any incentive earned under the PBR sharing mechanism.

The substance of the test for inadequate performance and, hence, consideration for disqualifying the Company from receiving a financial incentive is this:

> 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.

Each year at an Annual Review the performance metrics are reviewed in detail with regard to actual results achieved and the reasons for variances from the target. FortisBC provides information relating to the year's performance measured from October 1 to September 30 in each metric and expects that a determination will be made as to whether the Company had performed adequately in the past year, considering not only the overall aggregate results but also the circumstances under which the results were achieved. Under this framework, failure to meet one (or more) performance standard(s) does not necessarily constitute unacceptable performance.

In 2009 the Company met the Performance Standards targets, on a forecast basis, for 12 of the 13 metrics, with the exception of the Generator Forced Outage Rate. FortisBC did not earn a financial incentive as a direct result of allowing or causing its performance on any of these metrics to deteriorate in a material way and is therefore entitled to earn its portion of the financial incentive. Overall, the Company's performance on its metrics in 2009 was improved over 2008. Further detail regarding these results can be found in Tab 8.

2.12 Prior Years' Directives

FortisBC has provided in Appendix A a list of Commission prior years' directives applicable to this Application along with the Company's response to these directives.

2.13 Process for the Application

The PBR Plan provides for a review of current year financial and non-financial performance (“Annual Review”) and a Workshop to detail the 2010 Revenue Requirements to be followed by a Negotiated Settlement Process to determine rates for the upcoming year.

FortisBC proposes the following regulatory timetable for review of this application:

Registration of Intervenors and Interested Parties	Friday, October 9
Information Requests Issued to FortisBC	Friday, October 16
Responses to Information Requests by FortisBC	Friday, October 30
FortisBC files advance materials for Annual Review	Monday, November 2
Annual Review, Revenue Requirements Workshop	Tuesday, November 17
Negotiated Settlement Process	Wednesday, November 18

1 The following abbreviations have been used throughout this Application.

List of Abbreviations	
2005-2024 System Development Plan	"SDP"
2009-2010 Capital Expenditure Plan	“2009/10 Capital Plan”
2010 Operating and Maintenance	“Gross O&M”
Advanced Metering Infrastructure	"AMI"
All Injury Frequency Rate	"AIFR"
Allowance for Funds Used During Construction	"AFUDC"
Asset Retirement Obligations	“ARO”
BC Consumer Price Index	"CPI"
Brilliant Power Purchase Agreement	"BPPA"
Brilliant Terminal Station	“BTS”
British Columbia Gross Domestic Product	“GDP”
British Columbia Transmission Corporation	"BCTC"
British Columbia Utilities Commission	"BCUC" or “Commission”
Capital Cost Allowance	“CCA”
Canadian Accounting Standards Board	"AcSB"
Canadian Electricity Association	“CEA”
Canadian Institute of Chartered Accountants	“CICA”
Canal Plant Agreement	"CPA"
Certificate of Public Convenience and Necessity	"CPCN"
City of Grand Forks	“Grand Forks”
City of Kelowna	“Kelowna”
City of Penticton	“Penticton”
Columbia Power Corporation	"CPC"
Commission Order G-58-06	"2006 NSA"
Commission Order G-193-08	“2009 NSA”
Construction Work in Progress	"CWIP"
Consumer Price Index	"CPI"
Contribution in aid of construction	“CIAC”
Cooling Degree Days	"CDD"
Corporation of Nelson	“Nelson”
Cost of Service Analysis	“COSA”
Customer Average Interruption Duration Index	“CAIDI”
Customer Satisfaction Index	“CSI”
Demand Side Management	"DSM"
Distribution Substation Automation	“DSA”
District of Summerland	“Summerland”
Federal Goods and Services Tax	“GST”

List of Abbreviations	
Forced Outage Rate	"FOR"
General Wheeling Agreement	"GWA"
Generally Accepted Accounting Principles	"GAAP"
Gigawatt hours	"GWh"
Great Lakes Power Distribution Inc.	“GLPD”
Guarantee of Non Reclose	“GNR”
Harmonized Sales Tax	“HST”
Heating Degree Days	"HDD"
Independent Power Producer	"IPP"
Injury Severity Rate	"ISR"
International Accounting Standard	“IAS”
International Accounting Standards Board	“IASB”
International Financial Reporting Interpretations Committee	“IFRIC”
International Financial Reporting Standards	"IFRS"
Load Tap-Changer	“LTC”
Lost Time Injuries	"LTI"
Mandatory Reliability Standards	“MRS”
Medical Aid	"MA"
Medium Term Note	“MTN”
Megawatt	"MW"
Megawatt hours	"MWh"
Momentary Average Interruption Frequency Index	“MAIFI”
Negotiated Settlement Process	“NSP”
North American Electric Reliability Corporation	“NERC”
Okanagan Transmission Reinforcement	“OTR”
Open Access Transmission Tariff	"OATT"
Operating and Maintenance	"O&M"
Performance Based Regulation	"PBR"
Power Purchase Agreement	"PPA"
Productivity Improvement Factor	"PIF"
Property, Plant and Equipment	“PP&E”
Provincial Sales Tax	“PST”
Rate Design Application	“RDA”
Return on Equity	"ROE"
Right-of-way	“RoW”
System Average Interruption Duration Index	"SAIDI"
System Average Interruption Frequency Index	"SAIFI"
Teck Metals Ltd.	“Teck”
Telephone Service Factor	“TSF”

List of Abbreviations	
Transmission and Distribution	“T&D”
University of British Columbia, Okanagan campus	“UBC”
Upgrade and Life Extension	"ULE"
Use per customer	"UPC"
Vehicle Incident Rate	"VIR"
Western Electricity Coordinating Council	“WECC”