FORTISBC

Preliminary 2011 Revenue Requirements

Tab 2

Executive Summary

2.0 Introduction

In 2006, FortisBC Inc. (“FortisBC” or the “Company”) 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 2010 Revenue Requirements was approved by Commission Order G-162-09.

The Company strongly believes that the PBR Plan has been beneficial to FortisBC customers. Performance metrics have generally been maintained or improved, while encouraging the Company to operate as effectively and efficiently as possible. Examples of PBR benefits to customers are incremental “Other Income” such as revenue from third party pole contacts, incremental transmission wheeling, and incremental tax saving.

The 2011 Revenue Requirements Application will be the final such application to be submitted under the current PBR Plan.

The Company will file its 2012 Revenue Requirements Application in 2011, which will be based on a fully developed cost-of-service revenue requirement.

FortisBC, as a regulated public utility operating in the Province of British Columbia, has a mandate to provide safe, reliable service to its customers. It must fulfill this requirement against a backdrop of provincial policy and legislation such as the *2007 Provincial Energy Plan* (the “Energy Plan”), *Utilities Commission Act*, R.S.B.C. 1996, c.473 (“UCA”) and the *Clean Energy Act, S.B.C. 2010.C.22* (“CEA”), that was enacted in 2010. In addition, as costs related to the provision of such service are ultimately borne by its customers, the Company strives to ensure that rates are reflective of prudently incurred costs that result from sound decision making and good utility practice.

The Company must also give regard to the non-financial measures incorporated into the performance standards that are further discussed in Tab 8 of the Application. All of these factors are reflected in the Application.

The PBR mechanism under which the Company operates sets the gross Operating and Maintenance ("O&M") costs by formula as discussed in Section 3.2 of Tab 3. Factors for inflation and productivity for 2011 were agreed upon as part of the 2009 Negotiated Settlement Agreement ("NSA"). The values included in the determination of Gross O&M are a forecast BC CPI value of 2.3 percent and a 2011 Productivity Improvement Factor ("PIF") of 1.5 percent.

Based on financial and operating results achieved to July 31, 2010 the Company forecasts that the revenue required to provide service to its customers in 2011 is $276.2 million, which will necessitate a general increase in rates of 5.9 percent.

The Company will file, on or before November 1, 2010, an update to the Revenue Requirements Application that will include operating and financial results to September 30, 2010.

The Company believes that the required rate increase stemming from the increased revenue requirement in 2011 results from prudent and necessary expenditures including those factors that result from the formulaic components of the PBR regime under which it operates and that will close out with the end of this PBR term.

There are, however a number of variables within the calculation of the 2011 Revenue Requirement that present some uncertainty at the time of the filing of the Application. The timing and scope of the move to International Financial Reporting Standards ("IFRS"), the treatment and potential withdrawal of the Harmonized Sales Tax ("HST"), and the disposition of the Company's 2011 Capital Expenditure Plan ("2011 CEP"), are all without resolution at the time of filing. All of these factors are discussed in detail in the following sections of the Application.

At the date of this Application, although interim rates have been granted for BC Hydro, no final decision has been rendered by the Commission on the BC Hydro Fiscal 2011 Revenue Requirements Application ("BCH Application"). With respect to FortisBC's

2011 rates, the Company requests that the Commission approve its existing, interim rates pursuant to Commission Order G-127-10, issued August 5, 2010, so that rates may be firm. The Company further requests approval to implement any changes arising from a final decision in the BCH Application which affect the 2011 Power Purchase Expense or water fee charges by way of a flow through adjustment at the time of a Commission decision on that Application. This flow through treatment of BC Hydro rate increases would be consistent with prior years.

The Company has taken steps as noted in the Application to mitigate the impacts of this uncertainty but reserves the right to revisit any associated costs and unforeseen impacts resulting from any of the above issues.

2.1 Structure of the Application

As 2011 is the final year of operating under a historical PBR framework, this Revenue Requirements Application generally follows the same structure as in previous years. This executive summary is followed by tabs dealing with each major input to the Revenue Requirements as follows:

- Tab 3 – 2011 Revenue Requirements summary incorporating the information found in the sections that follow;
- Tab 4 – Financial Schedules providing detailed calculations of the information presented in Tab 3;
- Tab 5 – Load and Customer Forecast providing detail of load and customer count by rate class;
- Tab 6 – Power Supply – describing the Company's resource acquisition strategy and expectations for 2011;
- Tab 7 – Capital Expenditures – providing a brief summary of projects included in the Company's Capital Expenditure Plan for 2011; and
- Tab 8 – Performance Standards – summarizing the Company's results on non-financial measures against the targets established under PBR.

In addition, a number of appendices are attached to the Application that serve to further explain issues of relevance to the Revenue Requirement. These are:

- Appendix A - Prior Years Directives;
- Appendix B - Accounting Changes;
- Appendix C - Affiliate Transactions Report;
- Appendix D - O&M Savings Report;
- Appendix E - Capitalized Power Purchases; and
- Appendix F - Distribution Substation Automation Report.

2.2 Rate Drivers

The Company is requesting a rate increase of 5.9 percent effective January 1, 2011. The primary components of the requested rate increase are as follows:

i. **Power Supply**: Increases in Power Supply Costs are primarily due to increases in the price of power purchases and provincial water fees resulting in a 0.5 percent rate increase or $1.4 million of increased Revenue Requirements;

ii. **Operating**: O&M Expense net of capitalized overhead plus wheeling expense and other income are forecast to require a 0.2 percent rate increase or $0.5 million of increased Revenue Requirements;

iii. **Taxes**: Increases in property taxes and income tax results in a $1.8 million increase in Revenue Requirements or a 0.6 percent rate increase;

iv. **Financing**: Financing the Company's ongoing investment in new and upgraded infrastructure continues to be a primary rate driver, resulting in a 4.4 percent rate increase or $12.7 million in Revenue Requirements;

v. **Incentive and Other Adjustments**: Prior year incentive true-up and flow through adjustments reduce Revenue Requirements by $1.6 million, a 0.6 percent decrease in rates, which is offset by a decrease in ROE Sharing

Incentives by $2.2 million (or 0.8 percent increase in rates), resulting in an overall 0.2 percent rate increase or $0.6 million in Revenue Requirements.

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, 2010. On or before November 1, 2010, FortisBC will file updates to the 2010 and 2011 forecasts incorporating actual results to September 30, 2010.

2.3 Capital Expenditures

On June 18, 2010, FortisBC filed with the Commission its 2011 Capital Expenditure Plan ("2011 CEP"). The 2011 CEP outlines expenditures for capital spending including Generation, Transmission and Stations, Distribution, Demand Side Management ("DSM") and General Plant.

The 2011 CEP consists of projects with expenditures of $103.3 million in 2011 and $5.3 million in 2012 and is described in Tab 7. These expenditures are necessary to continue to provide reliable service, ensure public and employee safety, and to deliver Demand Side Management programs to the Company's growing customer base. Of those amounts, $37.1 million in 2011 and $3.8 million in 2012 have been previously approved by the Commission. FortisBC's capital expenditure program since 2005 has been guided by its long-term 2005 - 2024 System Development Plan (the "2005 SDP"), which identified the need for significant reinforcements in the bulk transmission system, regional transmission and distribution systems, and associated communications and protection systems. 2011 marks the completion of the major medium-term projects identified in the 2005 SDP. In 2011, the Company plans to complete and file a long-term Integrated System Plan, which will outline a 20-year horizon of planned investment spending on generation, transmission and distribution assets, general plant, and Demand Side Management in addition to the Company's plans to meet its electricity resource requirements.

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 in Appendix D of this application.

The regulatory process pertaining to the 2011 CEP is running concurrently with the 2011 Revenue Requirements Application. The Preliminary 2011 Revenue Requirements include the 2011 CEP as filed (with minor differences due to the timing of expenditures).

2.4 Load and Customer Forecast

Gross system load is forecast to be 3,500 GWh in 2011, a 1.7 percent increase over the current 2010 normalized forecast of 3,443 GWh. The load increase forecast for 2011 is related mainly to increases in the industrial and wholesale sectors.

The 2011 winter peak forecast is 701 megawatts ("MW"); 3 MW higher than in the 2010 Revenue Requirements filing. The 2011 forecast summer peak of 561 MW is 1 MW higher than in the 2010 Revenue Requirements.

Forecast load for 2011 for each customer class is summarized below:

- Residential load for 2011 is forecast at 1,248 GWh with the number of residential customers forecast to reach 99,566;
- The total projected load for the General Service class is forecast to grow by 0.7 percent in 2011 to reach 675 GWh;
- The total projected industrial load for 2011 is 269 GWh, an almost 8.3 percent increase from the current 2010 industrial load forecasts;
- Total forecast 2011 wholesale load is projected at 938 GWh which corresponds to 1.8 percent growth in energy consumption over the current 2010 forecast;
- The load of the Irrigation class has been estimated at 44 GWh; and
- The 2011 lighting forecast assumes lighting load at the 2010 forecast level of 13 GWh.

The determination of these load forecasts is discussed in more detail in Tab 5. The forecasts are based on results to July 31, 2010. On or before November 1, 2010, FortisBC will file updates to the 2010 and 2011 forecasts.

2.5 Power Supply

The 2011 Power Purchase Expense is forecast at $81.2 million compared to $75.2 million currently estimated for 2010. The increase is primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement, and the BC Hydro interim rate increase, which is partially offset by reduced market requirements and a reduction in the Brilliant Base rate. Further details can be found in Tab 6.

As noted above Power Purchase expense outlined in Tab 6 is based on interim BC Hydro rates as approved by Order G-47-10. 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 2011.

2.6 Gross Operating and Maintenance Costs and Capitalized Overhead

FortisBC establishes its O&M costs and capitalized overheads by formula during the PBR term. For 2011, the formula incorporates a Productivity Improvement Factor of 1.5 percent. The Base O&M Cost per Customer for the purposes of calculating Revenue Requirements under PBR is $382.64 in 2011. The Base O&M was derived by formula as approved by Commission Order G-193-08, adjusted by the HST savings of $1.33 per customer in 2011. The calculation of O&M costs are shown in Section 3.2.1 of Tab 3. The details of the 2011 HST savings are discussed in Section 3.3.3 of Tab 3.

2.7 Other Costs and Income

All other cost accounts including wheeling, interest, property taxes, income taxes, depreciation and amortization have been forecast for 2011 as discussed in Tab 3.

2.8 Financing

FortisBC expects to issue approximately $110 million of senior unsecured Medium Term Note (“MTN”) debentures, pursuant to an approved application, in the last quarter of

2010 to pay down the operating credit facility that it has been using to finance the Company's capital expenditure program and expects to finance 2011 capital expenditures through draws on its operating credit facility of $150.0 million.

FortisBC also expects to issue, subject to Commission approval, an additional $10 million of Common Share Equity in 2011 in order to maintain its approved capital structure of 60 percent debt and 40 percent equity.

The 2011 Allowed ROE for FortisBC is 9.90% which is based on applying FortisBC's risk premium of 40 basis points over the benchmark low-risk utility, Terasen Gas Inc ("TGI"). On December 17, 2009, the Commission issued a determination the Terasen Utilities' Return on Equity and Capital Structure Application and set the TGI ROE at 9.50%.

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

2.9 Flow Through Adjustments

There are a number of 2010 flow-through adjustments that are forecast to decrease Revenue Requirements by $1.9 million in 2011. The flow-through adjustments are detailed in Tab 3, section 3.5.

2.10 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 return.

The 2010 forecast of net income for incentive calculation purposes, shown on Table 3.6.1 in Tab 3, is $36.8 million which is $1.8 million lower than the approved net income for 2010. This falls within the 2 percent band subject to sharing and results in a customer share of the shortfall of $0.9 million. Expected Net Income was reduced primarily due to lower electricity sales volume than approved in accordance with the 2010 NSA which included increases to the Company's residential and industrial load forecasts. This was partially offset by lower power purchase, costs and operating expenses.

2.11 Deferred Costs

Deferred 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.

2.12 Performance Standards

Performance Standards for the PBR term were agreed to as part of the 2006 and 2009 Negotiated Settlement Agreements approved by Commission Orders G-58-06 and G-193-08. 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.

The 2010 Performance Standards are expected to meet targets, on a forecast basis, for 10 of the 13 metrics. The forecast targets for All Injury Frequency Rate ("AIFR"), Vehicle Incident Rate ("VIR"), and System Average Interruption Duration Index ("SAIDI") are not expected to be met.

These results indicate that FortisBC has continued to focus on these measures and has made no compromises in operational performance, however, for 2010 there are no incentive funds to be earned.

2.13 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.

2.14 International Financial Reporting Standards

Throughout 2010, the Company continued with its IFRS implementation project as outlined in Appendix B. There is still uncertainty around the accounting for regulated assets and liabilities. The Canadian Accounting Standards Board issued a Decision Summary in September 2010 allowing Canadian entities with rate regulated activities to defer implementing IFRS for an additional one year to January 1, 2012. FortisBC believes it is critical that IFRS be adopted for regulatory as well as external financial reporting purposes. During the IFRS transition year of 2011 the Company has requested regulatory approval of certain non-rate base deferrals arising as a result of IFRS accounting differences. These requests have been summarized in Schedule 1A of Tab 4 and Appendix B of this application.

2.15 Capitalization of Power Purchase Costs

During the negotiated settlement process for its 2010 Revenue Requirements Application, FortisBC agreed to the following commitment as documented by Order G-162-09, Appendix A, page 6:

> *FortisBC to provide Commission staff with its accounting opinion that capitalization is consistent with the CICA Handbook's section 3061.*

The Company has provided this information in Appendix E.

2.16 Process for the Application

The PBR Plan provides for a review of 2010 financial and non-financial performance ("Annual Review") and a Workshop to detail the 2011 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 8
Information Requests Issued to FortisBC	Friday, October 15
Responses to Information Requests by FortisBC	Friday, October 29
FortisBC files advance materials for Annual Review	Monday, November 1
Annual Review, Revenue Requirements Workshop	Tuesday, November 16
Negotiated Settlement Process	Wednesday, November 17

The following abbreviations have been used throughout this Application.

List of Abbreviations	
2005-2024 System Development Plan	SDP
2007 Provincial Energy Plan	Energy Plan
2010 Operating and Maintenance	Gross O&M
2010 Conservation and Demand Potential Review	CDPR
2011 Annual Review	Annual Review
2011 Capital Expenditure Plan	2011 CEP
72 Line	72L
73 Line	73L
74 Line	74L
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
BC Hydro Fiscal 2011 Revenue Requirements Application	BCH Application
Brilliant Power Purchase Agreement	BPPA
Brilliant Terminal Station	BTS
British Columbia Transmission Corporation	BCTC
British Columbia Utilities Commission	BCUC or Commission
Capital Cost Allowance	CCA
Canadian Accounting Standards Board	AcSB
Canadian Electrical Association	CEA
Canadian Pope & Talbot Inc. creditors	Canadian Defendants
Canal Plant Agreement	CPA
Certificate of Public Convenience and Necessity	CPCN
Clean Energy Act	CEA
Commission Order G-58-06	2006 NSA
Commission Order G-193-08	2009 NSA
Commission Order G-162-09	2010 NSA
Construction Work in Progress	CWIP
Consumer Price Index	CPI
Contribution in aid of construction	CIAC
Cooling Degree Days	CDD
Cost of Service Analysis	COSA
Customer Average Interruption Duration Index	CAIDI
Customer Satisfaction Index	CSI
Demand Side Management	DSM

List of Abbreviations	
Distribution Substation Automation	DSA
Federal Goods and Services Tax	GST
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
Input Tax Credit	ITC
Innovative Clean Energy Fund	ICE
Integrated System Plan	ISP
International Accounting Standards Board	IASB
International Accounting Standards Board Exposure Draft	IASB ED
International Financial Reporting Interpretations Committee	IFRIC
International Financial Reporting Standards	IFRS
Lost Time Injuries	LTI
Mandatory Reliability Standards	MRS
Medical Aid	MA
Medium Term Note	MTN
Megawatt	MW
Megawatt hours	MWh
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
Polychlorinated Biphenyls	PCBs
Pope & Talbot Inc.	Pope & Talbot
Power Purchase Agreement	PPA
Powerex Corp.	Powerex
Productivity Improvement Factor	PIF
Property, Plant and Equipment	PP&E
Provincial Sales Tax	PST

List of Abbreviations	
Rate Design Application	RDA
Return on Equity	ROE
Right-of-way	RoW
Shaw Cablesystems Ltd.	Shaw
Shaw Business Solutions Inc.	Shaw
System Average Interruption Duration Index	SAIDI
System Average Interruption Frequency Index	SAIFI
Teck Metals Ltd.	Teck
Telephone Service Factor	TSF
Terasen Gas Inc.	TGI
Transmission and Distribution	T&D
Trustee for Pope & Talbot Inc.	US Trustee
Undepreciated Capital Cost Allowance	UCC
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