# Appendix B

# COMPANY SPECIFIC INFORMATION FOR FEVI

## FortisBC Energy (Vancouver Island) Inc. ("FEVI")

FEVI is a company incorporated under the laws of the Province of British Columbia, operating since 1991. FEVI is engaged in sales and transportation services of natural gas to residential, commercial, and industrial customers in approximately 40 communities in service areas of Vancouver Island, Sunshine Coast, and Powell River, currently serving over 100,000 customers throughout the Province. FEVI's service is provided through approximately 6,360 kilometres of pipelines. FEVI's distribution network serves approximately 10 percent of natural gas customers in BC and delivers more than 2 percent of the total energy consumed in the Province. Table below summarizes FEVI's company profile.

| | |
|---|---|
| **Type of Utility** | Local Distribution Company |
| **Energy Product Offering** | Natural gas |
| **Service Area** | Vancouver Island, Sunshine Coast, and Powell River |
| **Rate Base*** | $779.9 (millions) |
| **Sales/Transportation Volumes*** | 34,131 TJs |
| **Number of Customers*** | 105,119 |
| **Customer Additions*** | 2,557 |
| **Customer Growth Rate*** | 2% |
| **Customer Profile by Demand*** | |
| Residential | 13% |
| Commercial | 21% |
| Industrial | 66% |
| **Customer Profile by Margin*** | |
| Residential | 41% |
| Commercial | 30% |
| Industrial | 29% |

*Based on 2012 Forecast, 2012-2013 RRA

## 1. Most recent Annual Report

- Annual Financial Statements for the Year-ended December 31, 2011

**Filed Confidentially**

**2. Credit Rating Agency reports for the utility and corporate parent since 2006:**

- Enclosed are Rating Agency reports for FEVI,
- Its direct corporate parent FortisBC Holdings Inc. (FHI) and its ultimate parent, Fortis Inc. (FTS).can be found in section 2 of FEI's Company Related Document filings

a. Debt Rating
- Rating Agency reports include annual debt ratings – See reports for FEVI (please note that DBRS reports are **filed Confidentially**)
- Rating Agency reports include annual debt ratings - See reports for FHI and FTS in section 2 of FEI's Company Related Document filings

b. Schedule showing the history of any debt rating changes since 2002
- See schedule – "Changes in ratings since 2002"
- For FHI and FTS, see schedule – "Changes in ratings since 2002" in section 2 of FEI's Company Related Document filings

c. Interest coverage ratio and other agency's key debt ratios since 2006
- Rating Agency reports include key ratios – See reports
- Rating Agency reports include key ratios – See reports for FHI and FTS in section 2 of FEI's Company Related Document filings

**Rating Action:** Terasen Gas (Vancouver Island) Inc.

## Moody's Assigns an A3 to Terasen Gas (Vancouver Island) Inc. Senior Unsecured Debentures

### Approximately $250 Million of Debt Securities Affected

Toronto, January 30, 2008 -- Moody's Investors Service announced that it has assigned an A3 rating to Terasen Gas (Vancouver Island) Inc.'s (TGVI) proposed issuance of up to $250 million senior unsecured debentures. The rating outlook is stable. This is the first time that Moody's has assigned a rating to TGVI.

TGVI's rating reflects the application of Moody's rating methodology for North American regulated gas distribution companies. In Moody's view, TGVI, like its sister company Terasen Gas Inc. (TGI), operates in a relatively supportive regulatory jurisdiction. Moody's views the supportiveness of the regulatory environment as offsetting, to some degree, the weakness of TGVI's financial profile in the near to medium term due to a proposed major capital project and TGVI's unique regulatory construct. Moody's analysis recognizes that TGVI's proposal to develop the Mt. Hayes LNG storage facility at an "all-in" cost that is not expected to exceed $200 million would increase TGVI's rate base by more than 40%, however, Moody's does not consider the Mt. Hayes project to be a significant credit challenge for TGVI for a number of reasons further detailed in Moody's Credit Opinion.

Moody's analysis also considered the competitiveness of natural gas on Vancouver Island relative to alternative forms of energy and TGVI's ability to charge rates that are both competitive and sufficient to recover its costs of service. Moody's believes that the progress that TGVI has made since 2003 in recovering its regulatory assets, principally the Revenue Deficiency Deferral Account, and the prospect of higher costs for alternate forms of energy provide TGVI with some flexibility to increase its revenues to offset the scheduled cessation of provincial royalty revenues and provide for higher rate of repayment of the government repayable contributions commencing in 2012 in accordance with the Vancouver Island Natural Gas Pipeline Agreement (VINGPA).

Reflecting Moody's expectations that the Mt. Hayes project will not pose a significant credit challenge and that TGVI will be able to offset the loss of provincial royalty revenues while charging competitive rates, Moody's believes that TGVI's financial results post 2011 are likely a better reflection of TGVI's normalized operations. Accordingly, Moody's has focussed on a set of normalized financial metrics in applying our North American Regulated Gas Distribution Industry rating methodology to TGVI. While Moody's does not ignore the risks associated with the Mt. Hayes project, the cessation of royalty revenues and the repayment of the government contributions, Moody's believes that if TGVI were to encounter a situation where it was unable to recover its costs of service while charging competitive rates, there is a high likelihood that TGVI and TGI would be merged and their rates harmonized. Moody's expects that such a merger and rate harmonization would materially enhance the competitiveness of gas on Vancouver Island relative to alternative forms of energy.

Terasen Gas (Vancouver Island) Inc. is a cost of service regulated gas distribution company headquartered in Surrey, British Columbia.

New York
William L. Hess
Managing Director
Corporate Finance Group
Moody's Investors Service
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

Toronto
Allan McLean
Vice President - Senior Analyst
Corporate Finance Group
Moody's Canada Inc.
(416) 214-1635

Moody's Investors Service

**Global Credit Research**
**Credit Opinion**
16 MAR 2009

**Credit Opinion: Terasen Gas (Vancouver Island) Inc.**

**Terasen Gas (Vancouver Island) Inc.**

*Canada*

**Ratings**

| **Category** | **Moody's Rating** |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | A3 |

**Contacts**

| **Analyst** | **Phone** |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| William L. Hess/New York | 212.553.3837 |

**Key Indicators**

**Terasen Gas (Vancouver Island) Inc.**

| | [1]**LTM** | **2007** | **2006** | **2005** | **2004** |
|---|---|---|---|---|---|
| ROE (%) [2] | **10.5%** | **10.5%** | **10.8%** | **10.9%** | **9.4%** |
| EBIT/Customer Base (US$) [3] | [4]**$ 654.0** | **$583.6** | **$508.8** | **$510.6** | **$462.1** |
| EBIT/Interest (x) | **2.7x** | **2.9x** | **2.6x** | **2.7x** | **2.3x** |
| RCF/Debt (%) | **11.5%** | **8.6%** | **10.6%** | **11.4%** | **11.2%** |
| Debt/Book Capitalization (Excluding Goodwill) (%) | **66.7%** | **67.5%** | **65.9%** | **64.5%** | **66.2%** |
| FCF/FFO (%) | **-25.3%** | **-68.0%** | **38.8%** | **-5.4%** | **10.3%** |

[1] To September 30, 2008 [2] Return on Average Equity [3] US$ EBIT/ Residential and Commerical Customers (Ex. Industrial) [4] EBIT/Customer base figures for the last twelve months ended September 30, 2008 are based on the most recent available customer figures (i.e. December 31, 2007)

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

**Opinion**

**Rating Drivers**

Relatively low-risk, cost of service regulated gas transmission and distribution utility with no unregulated operations.

Small customer base, high cost system and relatively weak credit metrics are balanced by a history of strong regulatory and political support.

Expiry of government subsidies in 2011 could cause TGVI's rates to be uncompetitive with alternate forms of energy and lead to fuel switching.

Development of Mt. Hayes LNG storage facility.

Strong regulatory ring-fencing mechanisms.

**Corporate Profile**

Headquartered in Surrey, British Columbia, Terasen Gas (Vancouver Island) Inc. (TGVI) is a regulated natural gas transmission and distribution utility serving approximately 95,000 customers on Vancouver Island and the Sunshine Coast. TGVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). TGVI is one of the smallest gas utilities rated by Moody's with a 2008 mid-year rate base of approximately $500 million.

TGVI is a wholly-owned subsidiary of Terasen Inc. (TER), a holding company which also owns 100% of Terasen Gas Inc. (TGI) and Terasen Gas Whistler Inc. (TGW), and a 30% interest in CustomerWorks, L.P. TER, and consequently TGVI, has been an indirect, wholly-owned subsidiary of Fortis Inc. (FTS) since May 17, 2007.

**SUMMARY RATING RATIONALE**

TGVI's A3 senior unsecured rating and stable outlook reflect TGVI's relatively low-risk business model and supportive regulatory and political environment balanced by normalized credit metrics that are generally in the Baa category. TGVI's normalized financial metrics are generally weaker than those of similarly rated U.S. local distribution company (LDC) peers such as Connecticut Natural Gas Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc. and UGI Utilities, Inc. However, TGVI's financial metrics are somewhat stronger than those of its sister company, TGI (A3, senior unsecured), reflecting the fact that the BCUC deems a higher level of equity for TGVI (40% vs. TGI's 35%) and allows a higher ROE (70 BP premium to TGI). Moody's recognizes that the weaker financial metrics of TGVI and TGI relative to similarly rated U.S. peers are largely a function of the relatively lower deemed equity and allowed ROE permitted by the BCUC. Moody's believes that this is offset to a significant degree by the supportiveness of the business and regulatory environments in Canada generally and in British Columbia specifically. While Moody's quantitative analysis has considered TGVI's historical and forecast financial performance, Moody's believes that TGVI's historical metrics are probably not representative of future performance due to the impact of regulatory deferrals and recoveries as well as government subsidies. Similarly, TGVI's near-term financial forecast is distorted by ongoing recovery of regulatory deferrals, the termination of government subsidies in 2011, and elevated capital expenditures. Accordingly, Moody's has focused on a set of normalized credit metrics that remove these distortions. While Moody's does not entirely discount the potential risks associated with TGVI's unique business and regulatory situation and its planned capital expenditures, we believe that these risks are manageable. Utilizing the normalized set of financial metrics, Moody's rating methodology for North American Regulated Gas Distribution Companies indicates an A3 rating for TGVI which mirrors TGVI's actual A3 senior unsecured rating.

**DETAILED RATING CONSIDERATIONS**

RELATIVELY LOW-RISK REGULATED GAS TRANSMISSION AND DISTRIBUTION UTILITY IN A SUPPORTIVE ENVIRONMENT

In general, Moody's considers gas distribution utilities to be at the low end of the risk spectrum within the universe of regulated utilities, both gas and electric. Similarly, we consider regulated utilities be generally lower risk relative to companies that are outside of the utility space and do not benefit from cost of service regulation. Accordingly, Moody's considers regulated gas LDCs like TGVI to be among the lowest risk corporate entities. Nevertheless, two key features of TGVI's operations cause its business risk to be higher than most gas LDCs. Firstly, TGVI's system has a relatively high capital cost on a per customer basis reflecting the significant investment in transmission infrastructure, including three sub-sea crossings, to reach the relatively small customer base on Vancouver Island. Secondly, as a consequence of the high capital cost of TGVI's system, its costs of service and therefore its rates are high. To ensure that natural gas was roughly cost competitive with fuel oil and electricity, the Province, the BCUC and TGVI agreed to cap TGVI's rates at levels similar to those of alternative forms of energy. Prior to 2003, TGVI's rates were insufficient to cover TGVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). TGVI financed the increases in the RDDA balance by issuing Class B subordinated debt instruments which were purchased by TER.

While the high cost of TGVI's system and the historically uncompetitive position of gas on Vancouver Island cause TGVI's business risk to be higher than that of most gas LDCs, Moody's believes that this higher risk and TGVI's relatively weak credit metrics are balanced by a long history of government support and a supportive regulatory environment. In support of its policy goal of ensuring the availability of natural gas on Vancouver Island, the Province of British Columbia has provided both financial and regulatory support to TGVI and its predecessors virtually since their inception. In the past, both the Province and the Federal Government have provided financial support to TGVI in the form of non-interest bearing loans. Ongoing Provincial support is provided through the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) under which the Province pays royalty revenues to TGVI that subsidize the cost of natural gas. The Province also provides regulatory support in the form of the Special Direction to the BCUC which governs the recovery of RDDA balances. Beginning in 2003, TGVI reached a point where, with the benefit of the Provincial royalty revenues, it was able to not only recover its costs of service but begin recovering the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. The terms of the Special Direction dictate that it will not expire before the RDDA balance has been fully recovered.

As the RDDA balance is recovered, TGVI utilizes the cash recovered to retire the Class B subordinated debt instruments purchased by TER. TGVI currently anticipates that it will have fully recovered the RDDA balance by early 2010 which, all else being equal, is expected to result in a slight reduction in TGVI's rates in 2010. However, TGVI's rates are expected to increase substantially in 2012 to compensate for the lack of Provincial royalty revenues which are scheduled to terminate in 2011. While Moody's anticipates that TGVI may seek regulatory approval for some mechanism to smooth out these potential rate fluctuations, there can be no assurance that the BCUC would agree to any proposals that TGVI might make. In the absence of some smoothing mechanism, TGVI's rates during the 2010 to 2012 period are expected to be somewhat volatile.

In addition to support provided by the Provincial Government, TGVI has benefited from British Columbia's economic performance, which has until recently been relatively strong. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada. This view reflects the fact that regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced although these relative strengths have been tempered somewhat by deemed equity levels and allowed ROEs that have tended to be lower than in other Canadian provinces. TGVI benefits from deemed equity levels and allowed ROEs for ratemaking purposes that are higher than those of its A3-rated sister company, TGI. For rate-making purposes, the BCUC allows TGVI a deemed equity component of 40% vs. TGI's 35% and an allowed ROE that is 70 BP higher than TGI's which tends to cause TGVI's financial metrics to be somewhat stronger than those of TGI. TGVI's more favourable rate-making inputs relative to those of TGI reflect the relatively small size of TGVI's service territory and customer base as well as its relatively high investment in fixed assets on a per customer basis. TGVI's current rate settlement expires at the end 2009 and the company expects to file a two year rate application around mid-year 2009. With the expected elimination of the RDDA balance in 2010, Moody's expects that TGVI will seek and receive regulatory protection against key business risks such as commodity prices, customer demand, interest expense, pension costs and insurance costs. TGVI's sister company, TGI, currently benefits from regulatory protection against such risks.

EXPIRY OF GOVERNMENT ROYALTY REVENUES IN 2011 ADVERSELY IMPACTS COMPETITVENESS OF GAS RELATIVE TO ALTERNATE FORMS OF ENERGY

A material risk faced by TGVI is the competitiveness of natural gas relative to alternative forms of energy on Vancouver Island. As noted above, the development of TGVI's system was relatively expensive and only in recent years has TGVI accumulated a sufficiently large customer base to permit it to recover from ratepayers both its current costs of service and accumulated regulatory deferrals while charging rates that have been comparable to the costs of alternative forms of energy on Vancouver Island. Furthermore, TGVI has only been able to do this with the benefit of Provincial royalty revenues. The rate increases that will be required to offset the loss of Provincial royalty revenues post-2011 could cause TGVI's rates to exceed the cost of alternative forms of energy. However, we expect that the costs of alternative energy sources are likely to rise significantly over an extended period of time which could provide TGVI with some breathing room.

Nevertheless, if TGVI ultimately finds itself in a position where its rates are uncompetitive and ratepayers begin to use less gas or even convert to electricity or fuel oil, Moody's expects that TGVI and its ultimate shareholder, FTS, would seek to merge TGVI with TGI and harmonize their rates. Rate harmonization would be expected to eliminate the cost disadvantage of gas on Vancouver Island as the higher costs of TGVI's system would be spread across TGI's larger base of approximately 834,000 customers (roughly nine times the customer base of TGVI).

Clearly, FTS would be supportive of such a move as a means of preserving the value of its investment in TGVI, but Moody's also believes that the Province of British Columbia would likely be supportive as well. As noted above, the Province has long provided financial and regulatory support to TGVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is Moody's view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of TGVI's franchise. Moody's also notes that there is precedence for such a transaction within the Terasen group of companies: on November 2, 2006, Terasen Gas (Squamish) Inc. was amalgamated with TGI and the rates of the two entities were harmonized. While TGVI is considerably larger than Terasen Gas (Squamish), we believe the Squamish transaction is a positive precedent in the event that at some point in the future, the long-term competitiveness of TGVI's rates comes into question.

DEVELOPMENT OF MT. HAYES LNG STORAGE FACILITY

In November 2007, TGVI received conditional approval from the BCUC for the 1.5 billion cubic foot Mt. Hayes liquefied natural gas (LNG) storage facility. TGVI commenced construction of the project in 2008. Based on a cost estimate of approximately $215 million, including an allowance for funds used during construction (AFUDC), the value of the project would exceed 40% of the value of TGVI's 2008 mid-year rate base of $500 million. However, Moody's believes that this measurement overstates both the magnitude and importance of the project for a number of reasons. Firstly, Mt. Hayes is being constructed under an Engineering Procurement Construction (EPC) contract which has shifted much of the cost and schedule risk to the EPC contractor, Chicago Bridge & Iron (CB&I), who has successfully constructed a number of similar LNG projects. Secondly, by early 2009, TGVI had hedged the majority of the Mt. Hayes cost elements that were not transferred to CB&I under the EPC contract. As of early 2009, the project was on budget, on schedule and within the $200 million pre-AFUDC cost parameters established by the BCUC. Thirdly, the project will form part of TGVI's rate base but TGVI has entered into BCUC-approved 35 year contract with TGI under which TGI will pay for approximately two thirds of the facility's capacity in the early years of the contract. Therefore, initially only about a third of the project costs will be borne by TGVI's existing ratepayers. Over time, as TGVI grows and requires a greater share of Mt. Hayes' capacity, TGVI's ratepayers will be required to support an increasing share of the project's costs. Fourthly, Mt. Hayes is a rather modest project both in absolute terms and relative to the experience and expertise of TGVI's management team (TGVI shares a common management team with TGI, a utility with a rate base of approximately $2.5 billion). For these reasons, Moody's does not expect that the Mt. Hayes project will pose a significant credit challenge for TGVI.

TGVI expects to finance the development of Mt. Hayes primarily with debt until the project enters service and rate base which is currently expected to occur in 2011. Accordingly, during the construction period, TGVI's debt to capital will be elevated and its cash flow metrics will be depressed.

STRONG REGULATORY RING-FENCING SEPARATES TGVI FROM PARENT, TERASEN INC.

Moody's believes that TGVI's ring-fencing is very good relative to that of its peers outside of British Columbia. TGVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC (refer to Moody's October 14, 2005 Comment on Proposed Regulatory Ring-Fencing Conditions). The ring-fencing conditions provide that, unless otherwise approved by the BCUC, TGVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause TGVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. Moody's believes that the BCUC ring-fencing provisions effectively insulate TGVI from the greater financial and business risks of its parents, TER and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow Moody's to evaluate TGVI's credit profile on a stand-alone basis.

**Liquidity Profile**

Moody's believes that TGVI has sufficient liquidity resources to meet its needs in 2009. In evaluating a company's liquidity, Moody's typically assumes that the company loses access to new capital, other than amounts available under its committed credit agreements, for a period of 12 months. In this context, we then evaluate the company's various sources and uses of cash including the flexibility to defer or reduce uses of cash such as capital expenditures and dividends.

TGVI maintains a $350 million syndicated committed revolving credit agreement which matures on January 13, 2011. The credit agreement contains two maintenance covenants (debt to equity not greater than 70% and EBIT to interest expense not less than 2:1). As at September 30, 2008, TGVI's leverage and coverage were 63.2% and 3.89x, respectively, leaving significant headroom under the covenants. TGVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress. Moody's understands that at December 31, 2008, approximately $235 million was available under the $350 million committed facility reflecting approximately $115 million drawn against this facility.

TGVI is expected to generate approximately $40 million of adjusted funds from operations (FFO) in 2009. After dividends in the range of $20 million and capital expenditures and working capital changes of approximately $80 million, Moody's expects TGVI to be free cash flow (FCF) negative by approximately $60 million in 2009. Given the forecasted $60 million FCF shortfall and repayment of approximately $21 million Class B Instruments, TGVI's 2009 funding requirement is expected to be approximately $81 million. This is substantially less than the availability of approximately $235 million under TGVI's syndicated bank credit facility at December 31, 2008.

**Rating Outlook**

The stable outlook is predicated on TGVI's low business risk as a regulated gas distribution utility, the expectation that the Mt. Hayes project will be successfully completed on time and on budget and the expectation that TGVI will be able to recover its costs of service while charging rates competitive with the costs of alternative forms of energy following the cessation of provincial royalty revenues in 2011.

**What Could Change the Rating - Up**

It is unlikely that TGVI's rating would be upgraded absent material increases in the company's deemed equity thickness and/or allowed ROE that translated to significant improvements in TGVI's key credit metrics. At the A2, senior unsecured level, Moody's would expect TGVI's ROE to be approximately 11% or more, EBIT/Interest to be approximately 2.5x or more, RCF/Debt to be approximately 8.5% or more, Debt/Book Capitalization (Excluding Goodwill) to be below 60% and FCF/FFO to be approximately 0%.

**What Could Change the Rating - Down**

Notwithstanding TGVI's relatively low risk business profile, sustained weakening of TGVI's financial metrics resulting from an inability to recover its costs of service, lower deemed equity thickness, lower allowed ROE or other factors could result in a reduction of TGVI's rating. For instance, ROE below 9%, EBIT/Interest below 2.0x, RCF/Debt below 7%, Debt/Book Capitalization (Excluding Goodwill) above 65% and FCF/FFO below -15% would likely cause TGVI's senior unsecured rating to fall to Baa1. If the rates required to allow TGVI to recover its costs of service are uncompetitive with alternative forms of energy on Vancouver Island and TGVI experiences stagnation or loss of customers, TGVI's rating could be negatively impacted.

**Rating Factors**

**Terasen Gas (Vancouver Island) Inc.**

| **Rating Factors and Sub-Factors** [1] | **Aaa** | **Aa** | **A** | **Baa** | **Ba** | **B** | **Caa** |
|---|---|---|---|---|---|---|---|
| **Factor 1: Sustainable Profitability (20%)** | | | | | | | |
| a) Return on Equity (15%) [2] | | | 10.7% | | | | |
| b) EBIT to Customer Base (5%) [3] | $534.3 | | | | | | |
| **Factor 2: Regulatory Support (10%)** | | | | | | | |
| a) Regulatory Support and Relationship | | X | | | | | |
| **Factor 3: Ring-Fencing (10%)** | | | | | | | |
| a) Ring-Fencing | | X | | | | | |
| **Factor 4: Financial Strength and Flexibility (60%)** | | | | | | | |
| a) EBIT/Interest (15%) | | | | 2.7x | | | |
| b) Retained Cash Flow/Debt (15%) | | | | 10.2% | | | |
| c) Debt to Book Capitalization (Excluding Goodwill) (15%) | | | | | 66.0% | | |
| d) Free Cash Flow/Funds from Operations (15%) | | -11.5% | | | | | |
| **Rating:** | | | | | | | |
| a) Methodology Model Implied Senior Unsecured Rating | | | **A3** | | | | |
| b) Actual Senior Unsecured Equivalent Rating | | | **A3** | | | | |

[1] Three year averages (2005-2007) [2] Return on Average Equity [3] US$ EBIT/ Residential and Commercial Customers (Excluding Industrials)

commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

Moody's Investors Service

## Credit Opinion: Terasen Gas (Vancouver Island) Inc.

**Global Credit Research - 12 Mar 2010**

*Canada*

### Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | A3 |
| **Parent: Terasen Inc.** | |
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa2 |
| Subordinate -Dom Curr | Baa3 |
| **Parent: Terasen Gas Inc.** | |
| Outlook | Stable |
| Senior Secured -Dom Curr | A1 |
| Senior Unsecured -Dom Curr | A3 |

### Contacts



| Analyst | Phone |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| Donald S. Carter, CFA/Toronto | 416.214.3851 |



### Key Indicators

[1]**Terasen Gas (Vancouver Island) Inc.**

| | [2]**LTM** | **2008** | **2007** | **2006** | **2005** |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense | **4.2x** | **3.9x** | **3.8x** | **3.5x** | **3.6x** |
| (CFO Pre-W/C) / Debt | **14.5%** | **15.2%** | **13.5%** | **12.4%** | **16.5%** |
| (CFO Pre-W/C - Dividends) / Debt | **9.8%** | **11.6%** | **8.6%** | **10.6%** | **11.6%** |
| Debt / Book Capitalization | **61.2%** | **66.4%** | **67.2%** | **65.6%** | **64.2%** |

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments [2] Last twelve months ended September 30, 2009

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

### Opinion

#### Rating Drivers

Regulated gas transmission and distribution utility with no unregulated operations

High cost of service and small size balanced by strong political and regulatory support

Business risk associated with the expiry of Government royalty payments at the end of 2011

Elevated capex and leverage during construction of Mt. Hayes LNG storage facility.

Strong regulatory ring-fencing mechanisms.

## Corporate Profile

Terasen Gas (Vancouver Island) Inc. (TGVI) is a natural gas transmission and distribution utility serving approximately 98,000 customers on Vancouver Island and the Sunshine Coast. TGVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). TGVI is one of the smallest gas utilities rated by Moody's with a 2009 mid-year rate base of approximately $540 million.

TGVI is a wholly-owned subsidiary of Terasen Inc. (TER), a holding company which also owns 100% of Terasen Gas Inc. (TGI) and Terasen Gas Whistler Inc. (TGW). TER has been a wholly-owned subsidiary of Fortis Inc. (FTS) since May 17, 2007.

## SUMMARY RATING RATIONALE

TGVI's A3 senior unsecured rating and stable outlook reflect TGVI's status as a regulated gas local distribution company (LDC). However, TGVI's high cost of service and small size cause its business risk to be higher than most gas LDCs. In addition, TGVI's credit metrics are weaker than those of international peers. However, we view TGVI's high cost of service, small size and weak metrics as being balanced by the long history of supportive regulatory and political decisions.

The rating also reflects our expectation that various factors will cause TGVI's rates to rise over the next few years. Rising rates would negatively impact the competitiveness of natural gas relative to other forms of energy which could result in reduced demand for gas and even more upward pressure on rates. Nothwithstanding, we anticipate that gas will remain attractive relative to electricity, which is the primary alternative in TGVI's service territory, due to our expectation that electricity rates will increase significantly each year for the foreseeable future. However, if gas were to lose its cost advantage in TGVI's service territory, we believe that it is likely that TGVI and TGI would be merged and that rates would be harmonized across both service territories. We believe that rate harmonization would lower rates in TGVI's service territory and restore gas' cost advantage.

TGVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology.

## DETAILED RATING CONSIDERATIONS

HIGH COST OF SERVICE BALANCED BY STRONG POLITICAL AND REGULATORY SUPPORT

TGVI's system has a high capital cost per customer and has relied heavily on regulatory and political support to ensure that its rates have been competitive with the costs of other forms of energy. TGVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach the relatively small customer base on Vancouver Island. Also, TGVI's market penetration is generally lower than that of TGI.

To ensure that natural gas was roughly cost competitive with fuel oil and electricity, the Province, the BCUC and TGVI agreed to a number of mechanisms. Firstly, TGVI's rates have been capped at levels similar to those of alternative forms of energy. Secondly, the Province provides financial support under the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) in the form of royalty revenue payments to TGVI which subsidize consumers' gas costs. Thirdly, both the Province and the Federal Government have provided TGVI with non-interest bearing loans.

Prior to 2003, TGVI's rates were insufficient to cover TGVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). In 2003 TGVI reached a point where, with the benefit of the Provincial royalty revenues, it was able to recover its costs of service and also begin to recover the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. By late 2009, TGVI had fully recovered the RDDA and begun to accumulate revenue surpluses.

In addition to support provided by the Provincial Government, TGVI has benefited from British Columbia's economic performance, which has until recently been relatively strong. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada. This view reflects the fact that regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced.

RATE PRESSURES COULD ADVERSELY IMPACT DEMAND

There are a number of factors which we believe will cause TGVI's rates to rise over the next few years. Depending on the extent of the increase in TGVI's rates and the degree to which the costs of alternative sources of energy increase, it is possible that the competitiveness of TGVI's rates and therefore the demand for gas within TGVI's service territory could be adversely impacted. In the extreme, the loss of a cost advantage could lead to spiraling rate increases and demand destruction. While we do not believe this to be a likely scenario, if it were to occur, we expect that TGVI and TGI would be merged and their rates would be harmonized. Rate harmonization would be expected to eliminate the cost disadvantage of gas on Vancouver Island as the higher costs of TGVI's system would be spread across TGI's larger base of approximately 839,000 customers (more than eight times TGVI's customer base).

While TGVI has been able to recover its costs of service and the accumulated RDDA balances since 2003, it has only been able to do so with the benefit of the Provincial royalty payments. Under the terms of the VINGPA, these royalty payments terminate at the end of 2011. Consequently, TGVI's rates will need to increase in 2012 to offset the loss of the Provincial royalty revenues. Initially, the rate impact of the loss of royalty revenues is expected to be partially mitigated by the amortization of accumulated revenue surpluses that are anticipated to occur during 2010 and 2011. Pursuant to the BCUC-approved negotiated settlement for TGVI's 2010/2011 rates, the company expects to recover more than its cost of service during those two years and will record any surpluses in a new deferral account, the Rate Stabilization Deferral Account or RSDA. Following the termination of the Provincial royalty revenues, the RSDA balance will be amortized and therefore reduce the need to increase rates to offset the lost royalty revenues. However, when the RSDA has been fully amortized, TGVI's rates will need to increase.

As of December 2009, the balance of TGVI's Provincial and Federal non-interest bearing loans was approximately $53 million. TGVI anticipates that this amount will be repaid between 2012 and 2016. As these loans are repaid, TGVI's rate base will increase by a like amount since these loans are treated as an offset to rate base for regulatory purposes.

In 2011, TGVI's Mt. Hayes liquefied natural gas (LNG) storage facility (described below) is expected to enter service and increase rate base by roughly $215 million. While the majority of the costs associated with Mt. Hayes will be covered by contractual payments from TGI, TGVI's customers will have to absorb roughly one third of the costs of Mt. Hayes through higher rates.

While we see upward pressure on TGVI's rates, we also expect the costs of alternative forms of energy to rise which could help preserve gas' cost advantage. For example, we note that BC Hydro applied for an effective 9.26% increase in its rates effective April 1, 2010. Moody's anticipates that the price of electricity in British Columbia will grow at well in excess of the rate of inflation for an extended period of time which could provide TGVI with some breathing room.

However, we believe that the Province of British Columbia would be supportive if rate harmonization were ultimately required to preserve gas competitiveness in TGVI's service territory. The Province has long provided financial and regulatory support to TGVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is Moody's view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of TGVI's franchise. Moody's also notes that there is a precedent for such a transaction within the Terasen group of companies: in November 2006, Terasen Gas (Squamish) Inc. was amalgamated with TGI and the rates of the two entities were harmonized. While TGVI is considerably larger than Terasen Gas (Squamish), we believe the Squamish transaction is a positive precedent in the event that at some point in the future, the long-term competitiveness of TGVI's rates comes into question.

VOLATILE CREDIT METRICS IN NEAR TERM

In December 2009, the BCUC set its benchmark ROE for 2010 at 9.5% and decided to abandon its automatic ROE adjustment mechanism. In that same decision, the BCUC reduced TGVI's ROE premium to 50 basis points (BP) from 70 BP. On balance, the decision is slightly positive for TGVI in that TGVI's 2010 ROE of 10% is higher than it would have been had the BCUC retained its automatic adjustment mechanism. Notwithstanding, we expect TGVI's credit metrics to be volatile for the next few years. During 2010 and 2011, TGVI's cash flows will benefit from the collection of revenues in excess of its cost of service. Commencing 2012 we expect cash flows to decline due to the cessation of the Provincial royalty revenues which will not be immediately offset by rate increases due to the non-cash amortization of revenue surpluses accumulated in 2010 and 2011. However, we expect there will be a new cash flow stream related to the Mt. Hayes project whose first full year of operation is expected to be 2012. The completion of Mt. Hayes should also cause TGVI's (Moody's-adjusted) interest costs to be lower at the margin as the short-term debt used to construct the facility will be replaced with a mix of long-term debt and equity. Currently, we do not expect TGVI's cash flows and metrics to stabilize until approximately 2014.

ELEVATED CAPEX DUE TO CONSTRUCTION OF MT. HAYES LNG STORAGE FACILITY

TGVI is currently constructing the 1.5 bcf Mt. Hayes LNG storage facility. Based on an estimated cost of approximately

$215 million, the value of the project would exceed 40% of TGVI's 2009 rate base of roughly $540 million. As of early 2010, the project was on schedule and within budget.

TGVI plans to finance Mt. Hayes primarily with short-term debt until the project is completed and is placed in rate base (currently expected to occur in 2011). On completion we expect that TGVI's ultimate parent, FTS, will provide an equity injection to bring TGVI's capital structure into line with the BCUC's deemed capital structure. Accordingly, during the construction period, TGVI's debt to capital will be higher than it otherwise would be and its cash flow metrics will be lower than they otherwise would be.

While the Mt. Hayes project is large relative to TGVI's rate base, Moody's does not expect that its construction will pose a significant credit challenge for TGVI given the progress to date and the experience of the TGI/TGVI management team. Once in service, Mt. Hayes will contribute to higher rates although this impact is mitigated by a contract under which TGI bears roughly two thirds of costs of the facility.

STRONG REGULATORY RING-FENCING SEPARATES TGVI FROM PARENT, TERASEN INC.

Moody's believes that TGVI's ring-fencing is very good relative to that of its peers outside of British Columbia. TGVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, TGVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause TGVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. Moody's believes that the BCUC ring-fencing provisions effectively insulate TGVI from the greater financial and business risks of its parents, TER and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow Moody's to evaluate TGVI's credit profile on a stand-alone basis.

**Liquidity Profile**

Moody's views TGVI's liquidity resources as weak pending a renegotiation or extension of its primary credit facility. TGVI maintains a $350 million syndicated committed revolving credit agreement which matures on January 13, 2011. The credit agreement contains two maintenance covenants (debt to equity not greater than 70% and EBIT to interest expense not less than 2:1). As at September 2009, TGVI's leverage and coverage were 64.4% and 4.1x, respectively, leaving reasonable headroom under the covenants. TGVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress. At December 2009, approximately $194 million was available under the facility.

TGVI is expected to generate approximately $66 million of funds from operations (FFO) in 2010. After and working capital changes and capital expenditures totaling approximately $90 million and dividends in the range of $20 million, Moody's expects TGVI to be free cash flow negative by approximately $45 million in 2010. While the availability under TGVI's credit agreement is expected to be sufficient to fund its anticipated 2010 funding requirement, we consider the fact that the facility matures within the 12 month horizon of our liquidity stress scenario to be a weakness. We anticipate that TGVI will address this issue during the second quarter of 2010.

**Rating Outlook**

The stable outlook reflects our expectation that TGVI will be able to recover its costs of service while charging rates competitive with the costs of alternative forms of energy following the cessation of provincial royalty revenues in 2011.

**What Could Change the Rating - Up**

We consider it unlikely that TGVI's rating would be upgraded in the foreseeable future. However, an upgrade to A2 would require a combination of materially stronger metrics and improved liquidity. We would expect to see CFO pre-WC Interest Coverage in excess of 4.5x; CFO pre-WC/Debt approaching 20% and Retained Cash Flow (RCF)/Debt in the low teens on a sustainable basis. This is unlikely to occur in the absence of significant increases in deemed equity and allowed ROE.

**What Could Change the Rating - Down**

A downgrade to Baa1 would likely be caused by changes in political and/or regulatory policy that disadvantage gas relative to electricity and cause a weakening of TGVI's financial metrics. For instance, CFO pre-WC Interest Coverage in the low 3x range; CFO pre-WC/Debt in the low teens and RCF/Debt in the mid single digit range on a sustained basis.

## Rating Factors

**Terasen Gas (Vancouver Island) Inc.**

| Regulated Electric and Gas Utilities Rating Methodology | Aaa | Aa | A | Baa | Ba | B |
|---|---|---|---|---|---|---|
| **Factor 1: Regulatory Framework (25%)** | | | X | | | |
| **Factor 2: Ability to Recover Costs and Earn Returns (25%)** | | X | | | | |
| **Factor 3: Diversification (10%)** | | | | | | |
| a) Market Position (10%) | | | | X | | |
| b) Generation and Fuel Diversity (0%) | | | | n/a | | |
| **Factor 4: Financial Strength, Liquidity & Financial Metrics (40%)** | | | | | | |
| a) Liquidity (10%) | | | X | | | |
| b) CFO pre-WC + Interest / Interest (7.5%) | | | | X | | |
| c) CFO pre-WC / Debt (7.5%) | | | | X | | |
| d) CFO pre-WC - Dividends / Debt (7.5%) | | | | X | | |
| e) Debt / Capitalization or Debt / RAV (7.5%) | | | | | | X |
| **Rating:** | | | | | | |
| a) Methodology Implied Senior Unsecured Rating | | | **A3** | | | |
| b) Actual Senior Unsecured Rating | | | **A3** | | | |

Moody's Investors Service

MOODY'S INVESTORS SERVICE

**Credit Opinion: FortisBC Energy (Vancouver Island) Inc.**

**Global Credit Research - 01 Aug 2011**

*Canada*

## Ratings

| **Category** | **Moody's Rating** |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | A3 |
| **Parent: FortisBC Holdings Inc.** | |
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa2 |
| **Parent: FortisBC Energy Inc.** | |
| Outlook | Stable |
| Senior Secured -Dom Curr | A1 |
| Senior Unsecured -Dom Curr | A3 |

## Contacts


| **Analyst** | **Phone** |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| William L. Hess/New York | 212.553.3837 |


## Key Indicators

[1]**FortisBC Energy (Vancouver Island) Inc.**

| | [2]**LTM** | **2010** | **2009** | **2008** | **2007** |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense | **4.4x** | **4.5x** | **4.0x** | **4.0x** | **3.8x** |
| (CFO Pre-W/C) / Debt | **15.6%** | **14.7%** | **13.3%** | **15.5%** | **13.5%** |
| (CFO Pre-W/C - Dividends) / Debt | **10.3%** | **9.6%** | **8.7%** | **11.8%** | **8.6%** |
| Debt / Book Capitalization | **62.3%** | **63.3%** | **60.7%** | **66.4%** | **67.2%** |

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. In addition, Moody's adjusts for one-time items [2] Last twelve months ended March 31, 2010

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

## Opinion

### Rating Drivers

Regulated gas local distribution company (LDC) with no unregulated operations

High cost of service and small size balanced by long history of political and regulatory support

Loss of provincial royalty payments at end of 2011 will necessitate higher rates or rate harmonization with FortisBC Energy Inc.

Higher rates would reduce relative competitiveness of gas relative to electricity and potentially lead to a cycle of demand destruction and rate increases

Rate harmonization would improve relative competitiveness of gas

Capex expected to moderate significantly by 2013

Strong regulatory ring-fencing mechanisms

Weak liquidity

### Corporate Profile

FortisBC Energy (Vancouver Island) Inc. (FEVI) is a gas LDC serving approximately 100,000 customers on Vancouver Island and the Sunshine

Coast in the province of British Columbia (BC). FEVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). FEVI, which has a forecasted 2012 rate base of approximately $788 million, is one of the smallest gas utilities that we rate.

FEVI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), a holding company which also owns 100% of FortisBC Energy Inc. (FEI, A3 senior unsecured) and FortisBC Energy (Whistler) Inc. (FEW, unrated). FHI has been a wholly-owned subsidiary of Fortis Inc. (FTS, unrated) since May 17, 2007.

**SUMMARY RATING RATIONALE**

FEVI's A3 senior unsecured rating and stable outlook reflect FEVI's status as a regulated gas LDC. However, FEVI's high cost of service and small size cause its business risk to be higher than that of most gas LDCs. In addition, FEVI's credit metrics are weaker than those of international peers. However, we consider FEVI's high cost of service, small size and weak metrics to be balanced by the relatively supportive business and regulatory environments in Canada in general and FEVI's long history of supportive regulatory and political decisions in particular.

The rating also reflects our belief that FEVI's cash flow and financial metrics will be significantly weaker in 2012 due to the scheduled cessation of royalty revenues from the Province of British Columbia at the end of 2011. We believe the weakness in FEVI's metrics will be short-lived because the company will either merge and harmonize rates with sister gas LDC, FEI, causing FEVI's rates to fall or increase its rates to offset the cessation of the royalty revenue. While a significant increase in FEVI's rates would be positive for FEVI's cash flow and financial metrics, it would reduce the relative competitiveness of gas versus electricity in FEVI's service territory. If an increase in FEVI's rates were to lead to a cycle of demand destruction and further rate increases, we continue to believe that amalgamation and rate harmonization, with FEI would be the most likely outcome.

FEVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology.

**DETAILED RATING CONSIDERATIONS**

SMALL SIZE AND HIGH COST OF SERVICE BALANCED BY HISTORY OF STRONG POLITICAL AND REGULATORY SUPPORT

FEVI's system has a high capital cost per customer and since inception FEVI has relied heavily on regulatory and political support to ensure that its rates have been competitive with the costs of other forms of energy. FEVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach its relatively small customer base on the Sunshine Coast and Vancouver Island and its lower market penetration relative to other gas LDCs including FEI.

We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. We consider the regulatory environment in BC to be one of the more supportive in Canada since regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced. In addition, FEVI benefits from a number of mechanisms agreed to by the BC Government and the BCUC that were designed to ensure that FEVI's gas rates were roughly cost competitive with electricity and fuel oil.

Firstly, FEVI's rates have historically been capped such that the cost of gas has been similar to the cost of alternative forms of energy. Secondly, the provincial government has subsidized consumers' gas costs by providing FEVI with royalty revenue payments under the Vancouver Island Natural Gas Pipeline Agreement (VINGPA). In accordance with the terms of the VINGPA, the royalty payments to FEVI cease at the end of 2011. Thirdly, both the Province and the Federal Government have provided FEVI with non-interest bearing loans.

Prior to 2003, FEVI's rates were insufficient to cover FEVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). In 2003, FEVI reached a point where, with the benefit of the provincial royalty revenues, it was able to recover more than its costs of service and therefore begin to recover the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. By late 2009, FEVI had fully recovered the RDDA and began to accumulate revenue surpluses.

SCHEDULED EXPIRY OF ROYALTY REVENUES PRESSURES NEAR-TERM FINANCIAL METRICS AND MEDIUM-TERM COMPETITIVENESS

In accordance with the VINGPA, the provincial royalty revenues (approximately $20 million in 2011) will cease at the end of 2011. We do not expect FEVI to immediately increase its rates to offset the loss of this cash flow because, subject to BCUC approval, the company plans to amortize the revenue surplus that it has accumulated since 2009. The accumulated revenue surplus, approved by the BCUC as a means of promoting rate stability, is expected to exceed $50 million by the end of 2011. While the amortization of this regulatory liability will allow FEVI to earn its allowed ROE on an accrual accounting basis, it does nothing to offset the loss of royalty revenue cash flows. Accordingly, we expect FEVI's cash flow and financial metrics to weaken materially in 2012.

In the absence of amalgamation and rate harmonization, discussed below, once the accumulated revenue surplus has been fully amortized, FEVI will need to increase rates significantly in order to cover its costs of service. While such a rate increase would allow FEVI to earn its allowed return on equity and would strengthen its cash flow credit metrics, it would reduce the relative competitiveness of gas versus other forms of energy, principally electricity, in FEVI's service territory. Although we expect BC electricity prices to continue to rise at rates well in excess of inflation for the foreseeable future, we note that the provincial government is once again reviewing the operations of British Columbia Hydro and Power Authority (BCH, Aaa) with a view to finding the right balance between required investments and rate increases. Similarly, while we currently anticipate that gas prices will remain relatively low for the foreseeable future, we are cognizant of the historical volatility of gas prices and the fact that current prices are low relative to those that prevailed during much of the preceding decade. Accordingly, there is a risk that significant increases in FEVI's delivery rates combined with higher gas commodity costs could cause gas to be uncompetitive with electricity which could lead to a cycle of demand destruction and further gas rate increases.

FEVI AND FEI PLAN TO SEEK APPROVAL TO AMALGAMATE AND HARMONIZE RATES

In their combined 2012-2013 revenue requirements application, filed with the BCUC on May 4, 2011, FEVI and FEI stated that they plan to apply to the BCUC in 2011 for permission to amalgamate and harmonize their rates effective January 1, 2013. In addition to BCUC approval, the utilities would also require the approval of the provincial government to amalgamate.

While we cannot predict the outcome of this effort, we continue to believe that the Province of British Columbia would be supportive if rate harmonization were ultimately required to preserve the competitiveness of gas in FEVI's service territory. The Province has long provided financial and regulatory support to FEVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is our view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of FEVI's franchise. We also note that there is a precedent for such a transaction within the Fortis group of companies: in November 2006, Terasen Gas (Squamish) Inc. was amalgamated with FEI and the rates of the two entities were harmonized. While FEVI is considerably larger than Terasen Gas (Squamish) Inc., we believe the Squamish transaction is a positive precedent.

COMPLETION OF MAJOR CAPITAL PROJECTS WILL RESULT IN A SIGNIFICANT EQUITY INJECTION AND REDUCTION IN CAPEX

FEVI will complete two major projects during 2011 and 2012: the Mt. Hayes liquefied natural gas storage facility and the internalization of its customer care system. On completion of these projects we expect FTS/FHI to inject significant equity into FEVI to bring its actual capital structure in line with its deemed 60/40 capital structure for rate-making purposes. We expect that that equity injections will cause FEVI's debt to capital to fall into the low 50% range in 2011 from about 63% in 2010.

Once in service in 2011, the Mt. Hayes project will provide FEVI with a new stream of cash flow. Under a BCUC-approved long-term contract, FEI is obligated to pay for roughly two thirds of the cost of the Mt. Hayes facility.

While the completion of these major projects will generate incremental cash flow and reduce FEVI's free cash flow shortfall, we do not expect the incremental cash flow to offset the cessation of provincial royalty revenues in 2011.

STRONG REGULATORY RING-FENCING SEPARATES FEVI FROM PARENT COMPANIES

We believe that FEVI's ring-fencing is very good relative to that of its peers outside of BC. FEVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC. The ring-fencing conditions provide that, unless otherwise approved by the BCUC, FEVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause FEVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support a non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. We believe that the BCUC ring-fencing provisions effectively insulate FEVI from the greater financial and business risks of its parents, FHI and FTS. The regulatory ring-fencing provisions combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow us to evaluate FEVI's credit profile on a stand-alone basis.

**Liquidity Profile**

We consider FEVI's liquidity resources to be weak pending a renegotiation or extension of its primary credit facility which is currently scheduled to mature on April 30, 2012.

FEVI is expected to generate approximately $58 million of CFO pre-WC during the 12 months ending June 30, 2012. After dividends in the range of $24 million and capital expenditures and working capital changes of about $66 million, we expect FEVI to be free cash flow negative by approximately $32 million. Since FEVI has no scheduled debt maturities during this period, we estimate that it will have a funding requirement of approximately $32 million.

While we estimate that availability under FEVI's $300 million syndicated committed revolving credit agreement is more than $200 million and well in excess of FEVI's funding requirement, the credit facility is currently scheduled to expire on April 30, 2012 which is inside the 12 month horizon of our liquidity stress scenario. Accordingly, we consider FEVI's liquidity to be weak. We expect that FEVI will seek to extend the term of this facility to at least December 31, 2012 in light of the company's announced plan to pursue amalgamation with FEI and FEW effective January 1, 2013. With the completion of the Mt. Hayes project in 2011 and the internalization of the customer care system in 2012, FEVI's future capital expenditures will be materially lower than those of recent years so we anticipate that FEVI might downsize the syndicated credit facility as it did in 2010 when the facility was reduced to $300 million from $350 million.

The $300 million credit agreement contains a single maintenance covenant (debt to equity not greater than 70%). As at December 2010, FEVI's leverage was 61.7% leaving reasonable headroom under the covenant. FEVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress.

**Rating Outlook**

The stable outlook reflects our expectation that the anticipated weakness in FEVI's cash flow and financial ratios will be short-lived. We continue to believe that if a cycle of demand destruction and rate increases were to arise, amalgamation of FEVI, FEI and FEW and the harmonization of rates across the various service territories would be the logical outcome.

**What Could Change the Rating - Up**

We consider it highly unlikely that FEVI's rating would be upgraded in the foreseeable future. However, an upgrade to A2 would require a combination of materially stronger metrics, improved competitiveness and improved liquidity. We would expect to see CFO pre-WC Interest Coverage in excess of 4.5x; CFO pre-WC/Debt approaching 20% and Retained Cash Flow (RCF)/Debt in the low teens on a sustainable basis. This is unlikely to occur in the absence of significant increases in FEVI's deemed equity and allowed ROE. In the absence of material decreases in gas commodity prices, which we do not believe is likely, significant increases in FEVI's deemed equity and allowed ROE would require rate increases which would exacerbate its already existing competitiveness challenges.

**What Could Change the Rating - Down**

A downgrade to Baa1 would likely be caused by changes in political and/or regulatory policy that disadvantages gas relative to electricity and causes a weakening of FEVI's financial metrics. For instance, CFO pre-WC Interest Coverage in the low 3x range; CFO pre-WC/Debt in the low teens and RCF/Debt in the mid single digit range on a sustained basis.

**Rating Factors**

**FortisBC Energy (Vancouver Island) Inc.**

| **Regulated Electric and Gas Utilities Industry** [1] | [2]**Current** | | | [3]**Moody's 12-18 month Forward View As of 07/26/2011** | |
|---|---|---|---|---|---|
| **Factor 1: Regulatory Framework (25%)** | **Measure** | **Score** | | **Measure** | **Score** |
| a) Regulatory Framework | | A | | | A |
| **Factor 2: Ability To Recover Costs And Earn Returns (25%)** | | | | | |
| a) Ability To Recover Costs And Earn Returns | | Aa | | | Aa |
| **Factor 3: Diversification (10%)** | | | | | |
| a) Market Position (10%) | | Baa | | | Baa |
| b) Generation and Fuel Diversity (0%) | | | | | |
| **Factor 4: Fin. Strength, Liquidity And Key Fin. Metrics (40%)** | | | | | |
| a) Liquidity (10%) | | A | | | Ba |
| b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%) | 4.2x | Baa1 | | 2.6x-3.4x | Ba1-Baa2 |
| c) CFO pre-WC / Debt (3 Year Avg) (7.5%) | 14.5% | Baa3 | | 10%-16% | Ba1-Baa3 |
| d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%) | 10.0% | Baa3 | | 5%-10% | Ba2-Baa3 |
| e) Debt/Capitalization (3 Year Avg) (7.5%) | 63.4% | Ba3 | | 52%-55% | Baa3 |
| **Rating:** | | | | | |
| a) Indicated Baseline Credit Assessment from Methodology Grid | | A3 | | | A3 |
| b) Actual Baseline Credit Assessment Assigned | | A3 | | | A3 |

Source: Moody's Financial Metrics.

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. In addition, Moody's adjusts for one-time items [2] Financial ratios reflect three year averages for 2008, 2009 and 2010. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

## Appendix B-2

# DBRS CREDIT RATING AGENCY REPORTS

(Provided in electronic format only due to
document size and in order to conserve paper)

**FILED CONFIDENTIALLY**

**Summary of FortisBC Energy (Vancouver Island) Inc. ("FEVI") changes in Credit Ratings from 2002-2012**

Prepared on July 3, 2012

| Rating Agency | Report Date | Rating Action | Rating |
|---|---|---|---|
| DBRS | February 2008 | Initiated | BBB(high) |

| Rating Agency | Report Date | Rating Action | Rating |
|---|---|---|---|
| Moody's | January 2008 | Initiated | A3 |

**3. Reports by investment analysts for the utility and corporate parent since 2006, where applicable:**

- There are no equity investment analyst reports for FEVI or its direct parent, FHI Inc.
- See section 3 of FEI's Company Related Documents for equity investment analyst reports for FEVI's ultimate parent, Fortis Inc. (FTS)
- There are no debt investment analyst reports for FEVI
- See section 3 of FEI's Company Related Documents filing for debt investment analyst reports for FEVI's ultimate parent, Fortis Inc. (FTS)

**4. All Prospectuses of Debt Offerings of the utility and/or its corporate parent within the last five years, if applicable:**

- The prospectuses of FEVI are **filed Confidentially**
- There were no Debt Offerings by FEI's direct parent, FortisBC Holdings Inc. (FHI)
- For Prospectuses of Debt Offerings by FEVI's ultimate parent, Fortis Inc., see section 4 of FEI's Company Related Documents

**a. Monthly (month end) spread data (market yield minus the yield on Government of Canada bond with similar time to maturity remaining) from 2006 to present date for a representative long-term bond issued by the utility**

- See attached Historical Spread Data in section 4 of FEI's Company Related Documents

**i. The time to maturity of both the utility bond and the government bond**

- See attached Historical Spread Data in section 4 of FEI's Company Related Documents

**ii. The trading liquidity of both bonds,**

- See attached Average Trading Volumes analysis in section 4 of FEI's Company Related Documents

**iii. The ratings on the bond for each quarter**

- See section 2.b of FEVI's Company Related Documents

**iv. For the latest placement of bond, the spread over the corresponding Government bond yields, the current spread and the maturity date**

- See attached Historical Spread Data in section 4 of FEI's Company Related Documents

## Appendix B-4

# PROSPECTUSES OF DEBT OFFERINGS

(Provided in electronic format only due to
document size and in order to conserve paper)

**FILED CONFIDENTIALLY**

5. **Full listing of each bond issue applicable for the 2012 Test Year including any future anticipated issues with full details (e.g. principal face value, nominal interest rate, effective rate if issued at discount or premium, relevant benchmark Government of Canada bond, credit spread benchmark, date of issue, date of maturity, length of maturity, etc.**

    - See attached for FEVI's bond issues for 2012 Test Year

**FEVI**
**Long-term Debt**
**29-Jun-2012**

| | Coupon | Maturity | Life | Yield to MATURITY Per FBC | Yield to Maturity Per RBC | 29-Jun-12 Market Price (a) ($CAD) | 29-Jun-12 Carrying Value ($CAD 000s) | 29-Jun-12 Market Price (% of Par) | 29-Jun-12 Market Value ($CAD 000s) | 29-Jun-12 Current GOC BM Per RBC | 29-Jun-12 Current Spread to BM bps | New Issue GOC BM | New Issue Spread to BM bps |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEVI | | | | | | | | | | | | | |
| Series 2008 | 6.05% | 15-Feb-38 | 25.65 | 3.934% | 3.933% | 133.967 | 250,000 | 133.967% | 334,918 | CAN 4 1JUN41 | 160 | CAN 5.75 1JUN33 | 183 |
| Series 2010 | 5.20% | 6-Dec-40 | 28.46 | 3.934% | 3.933% | 121.557 | 100,000 | 121.557% | 121,557 | CAN 4 1JUN41 | 160 | CAN 5 1JUN37 | 160 |
| Total FEVI | | | | | | | 350,000 | | 456,475 | | | | |

SOURCE: RBC Capital Markets, Company documents

**6. All Prospectuses of Equity Offerings of the utility and/or its corporate parent within the last six years, if applicable:**

- FEVI is a wholly-owned private entity and only issues equity to its parent, FortisBC Holdings Inc.
- FEVI is indirectly and wholly-owned by its ultimate parent, Fortis Inc (FTS – a TSX listed company).
- See section 6 of FEI's Company Related Documents for FTS equity offerings

**a. Details of any new equity issues from the financial market for the utility and/or corporate parent, if applicable:**

**7. Latest annual filing to the Commission of Operational and Financial Results.**

- See attached documents for FEVI's latest annual filing

FORTIS BC™

**Diane Roy**
Director, Regulatory Affairs - Gas
**FortisBC Energy Inc.**

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

April 30, 2012

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

**Re: FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.)**
**2011 Annual Report of FortisBC Energy (Vancouver Island) Inc.**

Please find attached, for the British Columbia Utilities Commission (the "Commission") review, three (3) copies of the FortisBC Energy (Vancouver Island) Inc. (the "Corporation") 2011 Annual Report of Actual results.

We trust that the Commission will find this filing in order. If there are any questions regarding this filing, please contact the undersigned.

Yours very truly,

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**

***Original signed:***

Diane Roy

Attachment

GAS COMPANIES

ANNUAL REPORT

OF

FortisBC Energy (Vancouver Island) Inc.

(Exact Legal Name of Utility)

16705 Fraser Highway, Surrey, B.C.  V4N 0E8

(Address of Principal Business Office)

TO THE

BRITISH COLUMBIA

UTILITIES COMMISSION

For the Period January 1, 2011 To December 31, 2011

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**

**ANNUAL REPORT FISCAL YEAR 2011**

**TABLE OF CONTENTS**


| | | Page No. |
|---|---|---|
| **Tab 1** | Declaration | 1.0.0 |
| | Directors and Officers | 1.1.0 |
| | Control Over Utility and Corporations Controlled by Utility | 1.2.0 |
| | Important Changes During the Year | 1.3.0 |
| | Comparative Balance Sheet – Assets | 1.4.0 |
| | Comparative Balance Sheet – Liabilities | 1.5.0 |
| | Reconciliation of Annual Report to Financial Statements | 1.6.0 |
| | Statement of Net Income and Retained Earnings | 1.7.0 |
| | Reconciliation of Financial Statement Net Income to Allowed Earned Return on Equity | 1.7.1 |
| | Deferred Regulatory Commission Expenses | 1.8.0 |
| | Lease/Rental Payments Charged to Operating Expenses | 1.9.0 |
| **Tab 2** | Gas Plant in Service Summary | 2.0.0 |
| | Gas Plant in Service | 2.1.0 |
| | Gas Plant Variance Explanation | 2.2.0 |
| | Gas Plant Under Construction & Held for Future Use | 2.3.0 |
| | Construction Overheads | 2.4.0 |
| | Contributions in Aid of Construction | 2.5.0 |
| **Tab 3** | Accumulated Provision for Depreciation Summary | 3.0.0 |
| | Accumulated Provision for Depreciation | 3.1.0 |
| **Tab 4** | Gas Account | 4.0.0 |
| | Gas Operating Revenues | 4.1.0 |
| | Other Revenue | 4.2.0 |

**Tab 5** Gas Operating Expenses Summary .......... 5.0.0
Gas Operating Expenses .......... 5.1.0
Gas Operating Expenses Variance Explanation .......... 5.2.0

**Tab 6** Pipeline Metres .......... 6.0.0

**Tab 7** Service Interruptions and Property Damage .......... 7.0.0

**Tab 8** System Map .......... 8.0.0

**Tab 9** Working Capital Requirements .......... 9.0.0
Cash Working Capital Requirements .......... 9.1.0
Working Capital – 13 Month Average .......... 9.2.0

**Tab 10** Earned Return .......... 10.0.0
Income Taxes .......... 10.1.0
UCC Continuities for Regulatory .......... 10.1.1
UCC Continuities for Income Tax .......... 10.1.2
Future Income Taxes (FIT) .......... 10.1.3

**Tab 11** Utility Rate Base .......... 11.0.0

**Tab 12** Cost of Capital .......... 12.0.0

**Tab 13** Executive Compensation .......... 13.0.0

**Tab 14** New Directions to the Utilities Under BCUC's Jurisdiction
And Other Related Information .......... 14.0.0

**Tab 15** Audited Financial Statements .......... 15.0.0

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.

## DECLARATION

## AS AT APRIL 30, 2012

**I, Roger Dall'Antonia, of Surrey, British Columbia, do hereby certify:**

1. That I am Vice President, Strategic Planning, Corporate Development & Regulatory Affairs of FortisBC Energy (Vancouver Island) Inc. with its Operations Centre at 16705 Fraser Highway, Surrey, British Columbia, V4N 0E8.

2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 of the Utilities Commission Act.

3. That I confirm the Utility's compliance with the Commission's financial directions contained in Decisions and Orders.

***Original signed:***

Roger Dall'Antonia,
Vice President, Strategic Planning, Corporate Development & Regulatory Affairs

Name, title and address of office or other person to whom any questions concerning this report should be addressed:

Diane Roy,
Director, Regulatory Affairs (Gas)

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C.
V4N 0E8

# FORTISBC ENERGY (VANCOUVER) INC.

## DIRECTORS AND OFFICERS

## AS AT DECEMBER 31, 2011

### OFFICERS

| Name | Business Address | Office Held |
|---|---|---|
| John C. Walker | 10th FLR - 1111 W Georgia St., Vancouver | President & CEO |
| Scott A. Thomson | 10th FLR - 1111 W Georgia St., Vancouver | Executive Vice President, Finance, Regulatory & Energy Supply |
| Douglas L. Stout | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Energy Solutions & External Relations |
| Dwain Bell | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Operations |
| Michael A. Mulcahy | 10th FLR - 1111 W Georgia St., Vancouver | Executive Vice President, Human Resources, Customer & Corporate Services |
| David C. Bennett | 10th FLR - 1111 W Georgia St., Vancouver | Vice President & General Counsel |
| Cynthia Des Brisay | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Energy Supply & Resource Development |
| Roger Dall'Antonia | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Finance & CFO; Treasurer |
| Robert M. Samels | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Business Planning |
| Thomas A. Loski | 10th FLR - 1111 W Georgia St., Vancouver | Vice-President, Customer Service |
| Debra G. Nelson | 10th FLR - 1111 W Georgia St., Vancouver | Corporate Secretary |
| Doyle Sam | 10th FLR - 1111 W Georgia St., Vancouver | Vice-President, Engineering & Generation |

### DIRECTORS

| Name | Business Address | Office Held |
|---|---|---|
| John C. Walker | 10th FLR - 1111 W Georgia St., Vancouver | Director and Chair |
| Michael A. Mulcahy | 10th FLR - 1111 W Georgia St., Vancouver | Director |
| Scott A. Thomson | 10th FLR - 1111 W Georgia St., Vancouver | Director |
| Douglas L. Stout | 10th FLR - 1111 W Georgia St., Vancouver | Director |

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.

## ANNUAL REPORT – 2011

## CONTROL OVER UTILITY AND CORPORATIONS CONTROLLED BY UTILITY

FORTIS INC.

100%

FORTISBC HOLDINGS INC.

100%

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.

## IMPORTANT CHANGES DURING THE YEAR

- Sales customers served increased from 100,136 in 2010 to 102,102 in 2011, a 1.96% increase.

- Gas consumed by sales customers increased from 11,491,394 GJ in 2010 to 12,547,590 GJ in 2011, a 9.19% increase.

- Gas sales revenues increased from $169,789,496 in 2010 to $184,210,712 in 2011, a 8.49% increase.

- Cost of gas sold increased from $74,343,207 in 2010 to $83,515,266 in 2011, an increase of 12.11%.

- Gas consumed by transportation customers decreased from 19,526,346 GJ in 2010 to 8,367,643 GJ in 2011, a 57.15% decrease. BC Hydro deliveries decreased from 12,940,996 GJ in 2010 to 827,383 GJ in 2011 as their plant was idle. There was no corresponding revenue decrease because revenues are set by contract volume.

- Gas transportation revenues increased from $23,620,718 in 2010 to $24,038,729 in 2011, an increase of 1.77%.

- During 2009, FEVI's revenues were sufficient to fully recover the Revenue Deficiency Deferral Account (RDDA), and also to create a revenue surplus. The 2009 Revenue Surplus Account captured the revenue surplus that was created during 2009 for the difference between revenues collected less the cost of service and the 2009 ending balance of the RDDA. The remaining balance of $1.481 million in this non-rate base deferral account was returned to customers in 2011.

- In 2011, there was $29.891 million of after tax additions including interest to the Revenue Surplus Deferral Account (RSDA), a non-rate base deferral account.

- FortisBC Energy (Vancouver Island) Inc. average staff levels increased 8.51% from 100.74 in 2010 to 109.31 in 2011.

- Approximately 36.34 kilometers of pipe (mains only) were installed in 2011 bringing the total pipe (mains) installed to 4,201 kilometers at year-end.

- In mid-April 2009, FEVI substantially completed the Whistler Natural Gas Intermediate Pressure Pipeline Project allowing for the commencement of the conversion of the FortisBC Energy (Whistler) Inc. distribution system from propane to natural gas. FEVI received a capital contribution from FEW to leave the existing FEVI customers unaffected by the construction of the Whistler Pipeline. The estimated final amount of the contribution of $17.034 million has been included in rate base effective April 1, 2009, at the time the pipeline was completed. This estimate will be refined to a final amount once all of the costs of the Whistler Pipeline construction project have been finally determined.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## COMPARATIVE BALANCE SHEET - Assets

| Line No. | Particulars | Account No. | As At Dec. 31/11 ($000) | As At Dec. 31/10 ($000) | Increase (Decrease) ($000) |
|---|---|---|---|---|---|
| | Gross Plant | | | | |
| 1 | Gas Plant in Service | 100 | $1,025,209 | $796,626 | $228,583 |
| 2 | Gas Plant Leased to Others | 101 | 0 | 0 | 0 |
| 3 | Gas Plant Held for Future Use | 102 | 0 | 0 | 0 |
| 4 | Retirement Work in Progress | 103 | 0 | 0 | 0 |
| 5 | Other Plant | 110 | 0 | 0 | 0 |
| 6 | Gas Plant Under Construction | 115 | 22,122 | 188,041 | (165,919) |
| 7 | Other Plant Under Construction | 116 | 0 | 0 | 0 |
| 8 | Utility Plant Acquisition Adjustment | 117 | 0 | 0 | 0 |
| 9 | Non-Rate Base Plant | 118 | 908 | 908 | 0 |
| 10 | Total Plant | | $1,048,239 | $985,575 | $62,664 |
| | Long Term Investments | | | | |
| 11 | Investments in Affiliated Companies | 120 | $0 | $0 | $0 |
| 12 | Other Long Term Investments | 121 | 0 | 0 | 0 |
| 13 | Sinking Funds | 122 | 0 | 0 | 0 |
| 14 | Miscellaneous Special Funds | 123 | 0 | 0 | 0 |
| 15 | Company Long Term Debt Owned | 124 | 0 | 0 | 0 |
| 16 | Second Mortgage Receivable | 125 | 0 | 0 | 0 |
| 17 | Total Long Term Investments | | $0 | $0 | $0 |
| | Current and Accrued Assets | | | | |
| 18 | Cash | 130 | $4,948 | $6,294 | ($1,346) |
| 19 | Special Deposits | 131 | 57 | 25 | 32 |
| 20 | Temporary Cash Investments | 132 | 10,000 | 7,908 | 2,092 |
| 21 | Accounts Receivable - Trade | 140 | 37,850 | 34,028 | 3,822 |
| 22 | Accounts Receivable - Other | 141 | 0 | 1,126 | (1,126) |
| 23 | Accounts Receivable - Affiliated Co's | 142 | 0 | 553 | (553) |
| 24 | Interest and Dividends Receivable | 147 | 0 | 0 | 0 |
| 25 | Materials and Supplies - Gas | 150 | 0 | 0 | 0 |
| 26 | Materials and Supplies - Other | 151 | 0 | 0 | 0 |
| 27 | Gas Stored Underground | 152 | 11,830 | 9,745 | 2,085 |
| 28 | Transmission Line Pack | 153 | 691 | 710 | (19) |
| 29 | Prepayments | 160 | 814 | 779 | 35 |
| 30 | Other Current and Accrued Accounts | 162 | 0 | 0 | 0 |
| 31 | Total Current and Accrued Assets | | $66,190 | $61,168 | $5,022 |
| | Deferred Charges | | | | |
| 32 | Future Income Taxes | | $73,619 | $64,481 | $9,138 |
| 33 | Unamortized Debt Discount and Expense | 170 | 3,356 | 3,387 | (31) |
| 34 | Extraordinary Plant Losses | 171 | 0 | 0 | 0 |
| 35 | Preliminary Surveys | 172 | 0 | 0 | 0 |
| 36 | Other Work in Progress | 173 | 0 | 0 | 0 |
| 37 | Unamortized Conversion Expenses | 175 | 0 | 0 | 0 |
| 38 | Public Improvements | 176 | 0 | 0 | 0 |
| 39 | Capital Stock Expense | 177 | 0 | 0 | 0 |
| 40 | Organization Expense | 178 | 0 | 0 | 0 |
| 41 | Other Deferred Charges | 179 | 3,540 | 10,421 | (6,881) |
| 42 | Total Deferred Charges | | $80,515 | $78,289 | $2,226 |
| 43 | Total Assets | | $1,194,944 | $1,125,032 | $69,912 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**COMPARATIVE BALANCE SHEET - Liabilities**

| Line No. | Particulars | Account No. | As At Dec. 31/11 | As At Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|---|
| | | | ($000) | ($000) | ($000) |
| | Capital Stock and Surplus | | | | |
| 1 | Preferred Stock | 200 | | | |
| 2 | Common Stock | 205 | $151,977 | $91,977 | $60,000 |
| 3 | Contributed Surplus | 210 | 62,259 | 62,259 | 0 |
| 4 | Contributions and Grants | 211 | 49,123 | 49,123 | 0 |
| 5 | Retained Earnings | 212 | 94,988 | 87,247 | 7,741 |
| 6 | Appropriated Retained Earnings | 215 | 0 | 0 | 0 |
| 7 | Excess of RE-determined Value of | | 0 | 0 | 0 |
| 8 | Plant over Depreciated Cost | 216 | 0 | 0 | 0 |
| 9 | Total Capital Stock & Surplus | | $358,347 | $290,606 | $67,741 |
| | Long Term Debt | | | | |
| 10 | Long Term Debt | 220 | $350,000 | $350,000 | $0 |
| 11 | Promissory Notes | 248 | 0 | 0 | 0 |
| 12 | Other Long Term Debt | 249 | 0 | 0 | 0 |
| 13 | Total Long Term Debt | | $350,000 | $350,000 | $0 |
| | Current and Accrued Liabilities | | | | |
| 14 | Loans and Notes Payable | 250 | $0 | $0 | $0 |
| 15 | Accounts Payable and Accrued | 251 | 14,354 | 21,435 | (7,081) |
| 16 | Accounts Payable - Affiliated Companies | 252 | 1,224 | 1,039 | 185 |
| 17 | Dividends Payable | 253 | 0 | 0 | 0 |
| 18 | Customers' Security Deposits | 254 | 1,504 | 2,252 | (748) |
| 19 | Customers' Advances for Construction | 255 | 289 | 289 | 0 |
| 20 | Taxes Accrued | 256 | 6,308 | 7,973 | (1,665) |
| 21 | Interest Payable and Accrued | 257 | 6,100 | 6,076 | 24 |
| 22 | Long Term Debt Due Within One Year | 258 | 77,526 | 124,526 | (47,000) |
| 23 | Other Current and Accrued Liabilities | 259 | 0 | 0 | 0 |
| 24 | Total Current and Accrued Liabilities | | $107,305 | $163,590 | ($56,285) |
| | Deferred Credits | | | | |
| 25 | Unamortized Debt Premium | 270 | $0 | $0 | $0 |
| 26 | Unearned Charges on Custs.' Acct. Rec.(Cr) | 271 | 0 | 0 | 0 |
| 27 | Gas Cost and Maintenance Equalization | 275 | 0 | 0 | 0 |
| 28 | Future Income Taxes | 276 | 73,616 | 64,481 | 9,135 |
| 29 | Other Deferred Credits | 279 | 69,622 | 42,976 | 26,646 |
| 30 | Total Deferred Credits | | $143,238 | $107,457 | $35,781 |
| | Reserves | | | | |
| 31 | Accumulated Depreciation - Gas Plant | 105 | $234,780 | $212,455 | $22,325 |
| 32 | Accumulated Amortization - Gas Plant | 106 | 0 | 0 | 0 |
| 33 | Accumulated Depreciation - Other Plant | 111 | 0 | 0 | 0 |
| 34 | Accumulated Amortization - Other Plant | 112 | 0 | 0 | 0 |
| 35 | Allowance for Loss in Value of Investments | 126 | 0 | 0 | 0 |
| 36 | Allowance for Doubtful Accounts | 145 | 1,261 | 913 | 348 |
| 37 | Insurance Reserves | 290 | 0 | 0 | 0 |
| 38 | Welfare and Pension Reserves | 291 | 0 | 0 | 0 |
| 39 | Injuries and Damages Reserves | 292 | 0 | 0 | 0 |
| 40 | Other Reserves | 293 | 0 | 0 | 0 |
| 41 | Accumulated Depreciation - Non-Rate Base Plant | 105 | 13 | 11 | 2 |
| 42 | Total Reserves | | $236,054 | $213,379 | $22,675 |
| 43 | Total Liabilities and Other Credits | | $1,194,944 | $1,125,032 | $69,912 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**RECONCILIATION OF ANNUAL REPORT TO FINANCIAL STATEMENTS**

| Line No. | Particulars | As At Dec. 31/11 ($000) | As At Dec. 31/10 ($000) | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Total Assets per page 1.4.0 of the Annual Report | $1,194,944 | $1,125,032 | $69,912 |
| 2 | Accumulated Depreciation | (234,795) | (212,466) | (22,329) |
| 3 | Contributions and Grants | (49,123) | (49,123) | - |
| 4 | Allowance for Doubtful Accounts | (1,261) | (913) | (348) |
| 5 | Deferred Charges/Credits Adjustment | (328) | 778 | (1,106) |
| 6 | Ineffective Hedge re Cost of Gas | 47,890 | 46,036 | 1,854 |
| 7 | Employee Benefit Plan | 2,199 | 1,350 | 849 |
| 8 | Reclass Future Income Taxes to assets | 2,806 | 534 | 2,272 |
| 9 | Plant Adjustment | 20 | (99) | 119 |
| 10 | Reclass Royalty Receivable to Liabilities | 794 | 468 | 326 |
| 11 | Reclass Accounts Receivable to Liabilities | (2,007) | 0 | (2,007) |
| 12 | Government Loan | 20,000 | 0 | 20,000 |
| 13 | Unamortized Debt Discount | (3,356) | (3,387) | 31 |
| 14 | Future Income Tax Gross-up | (973) | 1,552 | (2,525) |
| 15 | Total Assets per Financial Statements | $976,810 | $909,762 | $67,048 |
| 16 | Total Liabilities per page 1.5.0 of the Annual Report | $1,194,944 | $1,125,032 | $69,912 |
| 17 | Accumulated Depreciation | (234,795) | (212,466) | (22,329) |
| 18 | Contributions and Grants | (49,123) | (49,123) | - |
| 19 | Allowance for Doubtful Accounts | (1,261) | (913) | (348) |
| 20 | Deferred Charges/Credits Adjustment | (328) | 778 | (1,106) |
| 21 | Ineffective Hedge re Cost of Gas | 47,890 | 46,036 | 1,854 |
| 22 | Employee Benefit Plan | 2,199 | 1,350 | 849 |
| 23 | Reclass Future Income Taxes to assets | 2,806 | 534 | 2,272 |
| 24 | Plant Adjustment | 20 | (99) | 119 |
| 25 | Reclass Royalty Receivable to Liabilities | 794 | 468 | 326 |
| 26 | Reclass Accounts Receivable to Liabilities | (2,007) | 0 | (2,007) |
| 27 | Government Loan | 20,000 | 0 | 20,000 |
| 28 | Unamortized Debt Discount | (3,356) | (3,387) | 31 |
| 29 | Future Income Tax Gross-up | (973) | 1,552 | (2,525) |
| 30 | Total Liabilities per Financial Statements | $976,810 | $909,762 | $67,048 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **1.7.0**
**ANNUAL REPORT - 2011**
**STATEMENT OF NET INCOME**

| Line No. | Particulars | Account No. | For the year ended Dec. 31/11 | For the year ended Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|---|
| | | | ($000) | ($000) | ($000) |
| | Utility Income | | | | |
| 1 | Operating Revenue | 300 | $239,163 | $209,446 | $29,717 |
| 2 | Revenue from Gas Plant Leased to Others | 307 | 0 | 0 | 0 |
| 3 | Total Utility Operating Revenue | | $239,163 | $209,446 | $29,717 |
| | Operating Expense | | | | |
| 4 | Operating Expense including Cost of Gas | 301 | $112,756 | $95,593 | $17,163 |
| 5 | Maintenance Expense | 302 | 3,308 | 2,993 | 315 |
| 6 | Depreciation | 303 | 24,400 | 21,558 | 2,842 |
| 7 | Amortization | 304 | (358) | (2,066) | 1,708 |
| 8 | Municipal and Other Taxes | 305 | 9,629 | 9,601 | 28 |
| 9 | Income Taxes | 306 | 11,824 | 12,737 | (913) |
| 10 | Rent for Gas Plant Leased from Others | 308 | 0 | 0 | 0 |
| 11 | Total Utility Operating Expenses | | $161,559 | $140,416 | $21,143 |
| 12 | Net Utility Income | | $77,604 | $69,030 | $8,574 |
| | Other Income and Deductions | | | | |
| | Other Income | | | | |
| 13 | Revenue from Other Plant | 310 | $0 | $0 | $0 |
| 14 | Non-Operating Revenue | 312 | 0 | 0 | 0 |
| 15 | Income from Investments | 314 | 0 | 0 | 0 |
| 16 | Income from Investment in Affiliated Companies | 315 | 0 | 0 | 0 |
| 17 | Income from Sinking and Other Funds | 316 | 0 | 0 | 0 |
| 18 | Gain on Foreign Exchange | 317 | 0 | 0 | 0 |
| 19 | Other Income - Revenue Surplus & Recovery of AIP | 319 | (28,625) | (31,838) | 3,213 |
| 20 | AFUDC and Non Rate Base Interest Expense | 324 | 6,158 | 9,361 | (3,203) |
| 21 | Total Other Income | | ($22,467) | ($22,477) | $10 |
| | Other Income Deductions | | | | |
| 22 | Expense of Other Plant | 311 | $0 | $0 | $0 |
| 23 | Non-Operating Expense | 313 | 0 | 0 | 0 |
| 24 | Interest on Long Term Debt | 320 | 20,764 | 16,122 | 4,642 |
| 25 | Amortization of Debt Discount, Premium and Expense | 321 | 0 | 0 | 0 |
| 26 | Interest Due Affiliated Companies | 322 | 0 | 0 | 0 |
| 27 | Other Interest Expense | 323 | 4,668 | 3,643 | 1,025 |
| 28 | Loss on Foreign Exchange | 325 | (37) | 85 | (122) |
| 29 | Other Income Deductions | 329 | 0 | 0 | 0 |
| 30 | Total Other Income Deductions | | $25,395 | $19,850 | $5,545 |
| 31 | Income Before Extraordinary Items | | $29,742 | $26,703 | $3,039 |
| | Extraordinary Items | | | | |
| 32 | Extraordinary Income | 331 | $0 | $0 | $0 |
| 33 | Extraordinary Deductions | 332 | 0 | 0 | 0 |
| 34 | Net Extraordinary Items | | $0 | $0 | $0 |
| 35 | Net Income | 350 | $29,742 | $26,703 | $3,039 |
| 36 | Retained Earnings | | | | |
| 37 | Balance Beginning of Year | 212 | $87,247 | $85,544 | $1,703 |
| 38 | Balance Transferred from Net Income | 350 | 29,742 | 26,703 | 3,039 |
| 39 | Appropriations of Retained Earnings | 351 | 0 | 0 | 0 |
| 40 | Dividend Appropriations | 357 | (22,000) | (25,000) | 3,000 |
| 41 | Adjustments to Retained Earnings | 359 | 0 | 0 | 0 |
| 42 | Retained Earnings End of Year | 212 | $94,989 | $87,247 | $7,742 |

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## RECONCILIATION OF FINANCIAL STATEMENT NET INCOME TO ALLOWED EARNED RETURN ON EQUITY

| Line No. | Particulars | Reference | 2011 | 2010 |
|---|---|---|---|---|
| | | | ($000) | ($000) |
| 1 | NET INCOME PER FINANCIAL STATEMENTS | 15.0.0 | $29,743 | $26,701 |
| 2 | Rounding Difference | | (1) | 2 |
| 3 | NET INCOME PER PAGE 1.7.0 OF THE ANNUAL REPORT | 1.7.0 | $29,742 | $26,703 |
| 4 | Difference in Rate Base | | (132) | (28) |
| 5 | Non Rate Base Financing | | (3,654) | (5,850) |
| 6 | Non-Rate Base Depreciation | | 2 | 2 |
| 7 | Non-Regulatory O&M | | 0 | 588 |
| 8 | Rounding Difference | | 0 | - |
| 9 | ACHIEVED RETURN ON EQUITY | 10.1.0 | $25,958 | $21,415 |
| 10 | Special Direction Provision | | 1,867 | 1,867 |
| 11 | Variance in OM&A Expenses | | (1,180) | (1,379) |
| 12 | ALLOWED EARNED RETURN ON EQUITY | 12.0.0 | $26,645 | $21,903 |

[1] 2010 figures have been restated.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **1.8.0**
**ANNUAL REPORT - 2011**
**DEFERRED MATTERS**

| Line No. | Particulars | Balance **Dec 31, 2010** | Adjustment | Additions | Interest | Taxes | Amortization | Balance **Dec 31, 2011** | Mid-Year Balance |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gas Cost Variance Account | $3,282,074 | $0 | ($10,252,127) | $0 | $2,716,814 | ($3,282,074) | ($7,535,313) | ($2,126,619) |
| 2 | Energy Policy Related | | | | | | | | |
| 3 | Energy Efficiency & Conservation (EEC) | 1,186,702 | - | 2,404,490 | - | (637,190) | (119,601) | 2,834,402 | 2,010,552 |
| 4 | NGV Conversion Grants | - | - | - | - | - | - | - | - |
| 5 | Non-Controllable Items | | | | | | | | |
| 6 | Insurance Variance | - | - | 35,182 | - | (9,323) | (25,859) | - | - |
| 7 | Pension Adjustments | - | - | 703,372 | - | - | (703,372) | - | - |
| 8 | Olympic Security Costs | 133,472 | - | - | - | - | (44,491) | 88,981 | 111,226 |
| 9 | IFRS Conversion Costs | 78,894 | - | 45,569 | - | (12,076) | (26,298) | 86,090 | 82,492 |
| 10 | BCUC Levies | - | - | 17,471 | - | (4,630) | (12,841) | - | - |
| 11 | Cost of Current Applications | | | | | | | | - |
| 12 | 2010-2011 Revenue Requirement Costs | 126,324 | - | - | - | - | (126,324) | - | 63,162 |
| 13 | 2012-2013 Revenue Requirement Costs | - | - | 118,632 | - | (31,438) | - | 87,195 | 43,598 |
| 14 | 2009 ROE Capital Structure Costs | 55,220 | - | 3,101 | - | (822) | (13,805) | 43,694 | 49,457 |
| 15 | CCE CPCN Application Costs | 26,374 | - | - | - | - | (6,593) | 19,780 | 23,077 |
| 16 | Victoria Regional Centre CPCN Application | 12,064 | - | 33,930 | - | (8,992) | - | 37,003 | 24,534 |
| 17 | Other | | | | | | | | - |
| 18 | PCEC Start Up Costs | 1,095,680 | - | - | - | - | (43,900) | 1,051,780 | 1,073,730 |
| 19 | IFRS Transitional Deferral | 382,374 | - | 9,701 | - | - | - | 392,075 | 387,225 |
| 20 | Pension & OPEB Funding | (4,514,372) | - | 409,000 | - | - | - | (4,105,373) | (4,309,873) |
| 21 | Gains / Losses on Asset Disposition | 660,038 | - | 979,945 | - | - | - | 1,639,983 | 1,150,011 |
| 22 | Deferred Removal Costs | 324,642 | - | 201,508 | - | 129,403 | - | 655,554 | 490,098 |
| 23 | Vancouver Island HST Implementation | (48,535) | - | (86,230) | - | 25,452 | - | (109,312) | (78,924) |
| 24 | US GAAP Conversion Costs | - | - | 88,029 | - | (23,328) | - | 64,702 | 32,351 |
| | | | | | | | | | - |
| 25 | Total Rate Base Deferrals | $2,800,951 | $0 | ($5,288,426) | $0 | $2,143,872 | ($4,405,158) | (4,748,759) | (973,903) |
| 26 | Non-Rate Base Deferral Accounts | | | | | | | | |
| 27 | Revenue Surplus Deferral Account (RSDA) | (35,532,306) | - | (38,945,955) | (1,696,672) | 10,770,295 | - | (65,404,637) | (50,468,471) |
| 28 | 2009 Revenue Surplus | (1,481,000) | - | - | - | - | 1,481,000 | - | (740,500) |
| 29 | VIJV Legal Costs | 136,885 | - | (136,885) | - | - | - | - | 68,443 |
| 30 | IFRS Revenue Requirement Adjustment | (1,400,000) | - | 1,400,000 | - | - | - | - | (700,000) |
| 31 | Mark to Market - LNG Facility | 48,850 | - | (48,850) | - | - | - | - | 24,425 |
| 32 | CCE O&M Costs | 171,501 | - | 1,507,594 | 48,023 | (394,715) | - | 1,332,403 | 751,952 |
| 33 | Amalgamation Costs | - | - | 8,371 | - | - | - | 8,371 | 4,186 |
| 34 | 2012 Rate Design Application | - | - | 39,799 | 1,133 | (10,458) | - | 30,475 | 15,238 |
| 35 | Total Non - Rate Base Deferrals | ($38,056,069) | $0 | ($36,175,926) | ($1,647,516) | $10,365,122 | $1,481,000 | ($64,033,388) | ($51,044,727) |
| 36 | TOTAL DEFERRALS | ($35,255,118) | $0 | ($41,464,351) | ($1,647,516) | $12,508,994 | (2,924,158) | ($68,782,147) | ($52,018,630) |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**LEASE / RENTAL PAYMENTS CHARGED TO OPERATING EXPENSES**

| Line No. | Particulars | As at Dec. 31/11 | As at Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Office / Warehouse | $1,240,846 | $1,170,831 | $70,015 |
| 2 | Other | - | 1,717 | (1,717) |
| 3 | Total | $1,240,846 | $1,172,548 | $68,298 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **2.0.0**
**ANNUAL REPORT - 2011**
**GROSS GAS PLANT IN SERVICE**

| Line No. | Particulars | As at Dec. 31/11 | As at Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Intangible Plant | $30,219,845 | $28,563,005 | $1,656,840 |
| 2 | Local Storage | $198,156,594 | 0 | 198,156,594 |
| 3 | Transmission | 485,116,993 | 469,763,016 | 15,353,977 |
| 4 | Distribution | 514,412,715 | 501,035,343 | 13,377,372 |
| 5 | General Plant | 24,829,598 | 24,017,196 | 812,402 |
| 6 | TOTAL GAS PLANT IN SERVICE | $1,252,735,744 | $1,023,378,559 | $229,357,185 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**GROSS PLANT IN SERVICE**

| Line No. | Particulars | Balance 12/31/2010 | Opening + Curr Yr. Adjustments | CPCN'S | 2011 Additions | Retirements | Transfers/ Recovery | Balance 12/31/2011 |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 1 | **INTANGIBLE PLANT** | | | | | | | |
| 2 | 401-00 Franchise and Consents | $189,777 | $0 | $0 | $0 | $0 | $0 | $189,777 |
| 3 | 402-00 Other Intangible Plant | 1,219,037 | - | - | - | - | - | 1,219,037 |
| 4 | 461-00 Land Rights - Transmission | 6,870,799 | - | - | 661,092 | - | - | 7,531,891 |
| 5 | 471-00 Land Rights - Distribution | 1,865,911 | - | - | - | - | - | 1,865,911 |
| 6 | 402-00 Application Software - 8 year life | 15,814,921 | - | - | 389,565 | - | - | 16,204,487 |
| 7 | 402-00 Application Software - 5 year life | 2,602,560 | - | - | 606,183 | - | - | 3,208,743 |
| 8 | TOTAL INTANGIBLE PLANT | 28,563,005 | - | - | 1,656,840 | - | - | 30,219,845 |
| 9 | **LOCAL STORAGE PLANT** | | | | | | | |
| 10 | 440-00 Land | - | - | 1,081,819 | - | - | - | 1,081,819 |
| 11 | 441-00 Land Rights | - | - | 607,035 | - | - | - | 607,035 |
| 12 | 442-00 Structure & Improvements | - | - | 17,240,927 | - | - | - | 17,240,927 |
| 13 | 443-00 Gas Holders Storage | - | - | 59,997,715 | - | - | - | 59,997,715 |
| 14 | 448-00 Piping (Mount Hayes) | - | - | 11,466,528 | - | - | - | 11,466,528 |
| 15 | 448-00 Pre-treatment (Mount Hayes) | - | - | 28,658,770 | - | - | - | 28,658,770 |
| 16 | 448-00 Liquefaction Equipment (Mount Hayes) | - | - | 28,658,770 | - | - | - | 28,658,770 |
| 17 | 448-00 Send Out Equipment (Mount Hayes) | - | - | 22,916,452 | - | - | - | 22,916,452 |
| 18 | 448-00 Sub-station (Mount Hayes) | - | - | 21,606,471 | - | - | - | 21,606,471 |
| 19 | 448-00 Control Room (Mount Hayes) | - | - | 5,888,905 | - | - | - | 5,888,905 |
| 20 | 449-00 LNG Other equipment | - | - | 33,203 | - | - | - | 33,203 |
| 21 | TOTAL LOCAL STORAGE PLANT | - | - | 198,156,594 | - | - | - | 198,156,594 |
| 22 | **TRANSMISSION PLANT** | | | | | | | |
| 23 | 460-00 Land in Fee Simple | 2,842,425 | - | - | 355,321 | - | - | 3,197,747 |
| 24 | 462-00 Compressor Structures | 11,704,928 | - | - | 427,357 | - | - | 12,132,285 |
| 25 | 463-00 Measuring Structures | 7,517,073 | - | - | 53,578 | - | - | 7,570,650 |
| 26 | 464-00 Other Structures & Improvements | 129,522 | - | - | - | - | - | 129,522 |
| 27 | 465-00 Mains | 366,647,890 | - | 6,292,021 | 1,510,169 | (70,000) | - | 374,380,080 |
| 28 | 466-00 Compressor Equipment | 62,791,773 | - | - | 83,192 | - | - | 62,874,965 |
| 29 | 467-00 Measuring & Regulating Equipment | 14,349,675 | - | 5,261,884 | 1,474,596 | (113,731) | - | 20,972,424 |
| 30 | 468-00 Communication Structures & Equipment | 3,779,729 | - | - | 309,560 | (229,969) | - | 3,859,320 |
| 31 | TOTAL TRANSMISSION PLANT | 469,763,016 | - | 11,553,904 | 4,213,773 | (413,700) | - | 485,116,993 |
| 32 | **DISTRIBUTION PLANT** | | | | | | | |
| 33 | 470-00 Land in Fee Simple | 798,965 | - | - | - | - | - | 798,965 |
| 34 | 472-00 Structures & Improvements | 2,302,459 | - | - | 168,906 | (7,943) | - | 2,463,422 |
| 35 | 473-00 Services | 173,741,879 | - | - | 7,252,607 | (602,177) | - | 180,392,308 |
| 36 | 474-00 House Regulators & Meter Installations | 22,790,471 | - | - | 1,369,742 | - | - | 24,160,212 |
| 37 | 475-00 Mains | 279,552,779 | - | - | 4,692,815 | (230,659) | - | 284,014,935 |
| 38 | 476-00 Compressor Equipment | - | - | - | 127,840 | - | | 127,840 |
| 39 | 477-00 Measuring & Regulating Equipment | 8,304,699 | - | - | 362,486 | (59,718) | - | 8,607,467 |
| 40 | 478-00 Meters | 13,544,091 | - | - | 303,474 | - | - | 13,847,565 |
| 41 | TOTAL DISTRIBUTION PLANT | 501,035,343 | - | - | 14,277,869 | (900,497) | - | 514,412,715 |
| 42 | **GENERAL PLANT & EQUIPMENT** | | | | | | | |
| 43 | 480-00 Land in Fee Simple | 1,267,975 | - | - | - | - | - | 1,267,975 |
| 44 | 482-00 Structures & Improvements | 5,431,286 | - | - | 420,006 | (1,414) | - | 5,849,879 |
| 45 | - Furniture & Equipment | 980,966 | - | - | 73,655 | (350,698) | - | 703,923 |
| 46 | - Computer Hardware | 2,009,757 | - | - | 981,137 | (236,813) | - | 2,754,081 |
| 47 | - Computer Software | 312,386 | - | - | 72,127 | (4,576) | - | 379,936 |
| 48 | 484-00 Transportation Equipment | 5,080,252 | - | - | 617,686 | (503,605) | - | 5,194,333 |
| 49 | 485-00 Heavy Work Equipment | 1,440,678 | - | - | 82,256 | (41,856) | - | 1,481,079 |
| 50 | 486-00 Small Tools & Equipment | 6,757,001 | - | - | 390,327 | (529,711) | - | 6,617,617 |
| 51 | - Telephone | 736,895 | (99) | - | - | (156,021) | - | 580,775 |
| 52 | TOTAL GENERAL PLANT | 24,017,196 | (99) | - | 2,637,194 | (1,824,693) | - | 24,829,598 |
| 53 | **Net Plant In Service** | $1,023,378,559 | ($99) | $209,710,499 | $22,785,676 | ($3,138,890) | $0 | $1,252,735,744 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**GAS PLANT IN SERVICE VARIANCE**

| Line No. | Particulars | Dec. 31/11 Year End Balance | Dec. 31/10 Year End Balance | Increase (Decrease) |
|---|---|---|---|---|
| 1 | **Intangible Plant** | $30,219,845 | $28,563,005 | $1,656,840 |
| 2 | The increase in Intangible Plant is primarily attributed to software additions and land rights for the Mt. Hayes LNG Storage Facility. | | | |
| 3 | **Local Storage** | $198,156,594 | $0 | $198,156,594 |
| 4 | The increase is due to the Mt. Hayes LNG storage facility completed in 2011. | | | |
| 5 | **Transmission** | $485,116,993 | $469,763,016 | $15,353,977 |
| 6 | The increase in Transmission is primarily attributed to pipeline and measuring and regulating additions for the Mt. Hayes LNG Storage Facility. | | | |
| 7 | **Distribution** | $514,412,715 | $501,035,343 | $13,377,372 |
| 8 | FEVI constructed 26.14 kilometers of distribution mains and 36.92 kilometers of distribution services to add 1,965 customers. | | | |
| 9 | **General Plant** | $24,829,598 | $24,017,196 | $812,402 |
| 10 | The increase in General Plant is primarily attributed to computer hardware, transportation equipment, and structures. | | | |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **2.3.0**
**ANNUAL REPORT - 2011**
**GAS PLANT UNDER CONSTRUCTION & HELD FOR FUTURE USE (GPHFFU)**

| Line No. | Particulars | As at Dec. 31/11 | As at Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|
| | GAS PLANT UNDER CONSTRUCTION | | | |
| 1 | Direct Costs | $21,658,280 | $173,069,477 | ($151,411,197) |
| 2 | Overhead Allocation | - | - | - |
| 3 | AFUDC | 463,309 | 14,971,531 | (14,508,223) |
| 4 | Total Gas Plant Under Construction | $22,121,588 | $188,041,008 | ($165,919,420) |
| | GAS PLANT HELD FOR FUTURE USE | | | |
| 5 | Direct Costs | $0 | $0 | $0 |
| 6 | Overhead Allocation | - | - | - |
| 7 | AFUDC | - | - | - |
| 8 | Total Gas Plant Held for Future Use | $0 | $0 | $0 |

Note: AFUDC is Allowance for Funds Utilized During Construction.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **2.4.0**
**ANNUAL REPORT - 2011**
**CONSTRUCTION OVERHEAD (Direct & Indirect & AFUDC)**

| Line No. | Particulars | 2011 | 2010 |
|---|---|---|---|
| 1 | Overheads and AFUDC in Opening GPHFFU & Opening CWIP | $14,971,531 | $5,714,949 |
| 2 | Overheads and AFUDC Additions during year | 4,891,898 | 13,763,723 |
| 3 | Overheads and AFUDC in Closing GPHFFU & Closing CWIP | (463,309) | (14,971,531) |
| 4 | Total Overheads and AFUDC Cleared to Plant in Service | $19,400,121 | $4,507,140 |
| 5 | Cost of Construction of Overhead Bearing Plant | 12,927,204 | $12,471,609 |
| 6 | % Overheads to Construction | 150% | 36% |

Note: GPHFFU is Gas Plant Held for Future Use.
CWIP is Construction Work In Progress.
AFUDC is Allowance for Funds Utilized During Construction.

**ANNUAL REPORT - 2011**
**CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)**

| Line No. | Particulars | Balance 12/31/2010 | CPCN / Opening Adjustment | 2011 Additions / Reamortization | 2011 Additions | 2011 Retirements / Repayment | Balance 12/31/2011 | Mid-Year Balance |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 1 | **CIAC** | | | | | | | |
| 2 | | | | | | | | |
| 3 | Distribution Contributions | $96,770,027 | $0 | $0 | $695,904 | $0 | $97,465,931 | $97,117,979 |
| 4 | | | | | | | | |
| 5 | Transmission Contributions | 112,948,779 | - | - | 77,997 | - | 113,026,776 | 112,987,777 |
| 6 | | | | | | | | |
| 7 | Others | - | - | - | - | - | - | - |
| 8 | | | | | | | | |
| 9 | TGW Contribution for Whistler Pipeline | 17,034,000 | - | - | - | - | 17,034,000 | 17,034,000 |
| 10 | | | | | | | | |
| 11 | Government Loans Contribution | 49,123,337 | - | - | - | - | 49,123,337 | 49,123,337 |
| 12 | | | | | | | | |
| 13 | TOTAL Contributions | 275,876,143 | - | - | 773,901 | - | 276,650,044 | 276,263,094 |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| 17 | **Amortization** | | | | | | | |
| 18 | | | | | | | | |
| 19 | Distribution Contributions | (23,431,543) | - | - | (1,829,213) | - | (25,260,755) | (24,346,149) |
| 20 | | | | | | | | |
| 21 | Transmission Contributions | (31,073,130) | - | - | (2,303,993) | - | (33,377,123) | (32,225,127) |
| 22 | | | | | | | | |
| 23 | Others | - | - | - | - | - | - | - |
| 24 | | | | | | | | |
| 25 | TGW Contribution for Whistler Pipeline | (294,688) | - | - | (294,688) | - | (589,376) | - |
| 26 | | | | | | | | |
| 27 | Government Loans Contribution | (7) | - | - | - | - | (7) | (7) |
| 28 | | | | | | | | |
| 29 | TOTAL Amortization | (54,799,368) | - | - | (4,427,894) | - | (59,227,262) | (57,013,315) |
| 30 | | | | | | | | |
| 31 | **NET CONTRIBUTIONS** | $221,076,775 | $0 | $0 | ($3,653,993) | $0 | $217,422,782 | $219,249,779 |

# FORTISBC ENERGY (VANCOUVER ISLAND) INC. 3.0.0
## ANNUAL REPORT - 2011
## ACCUMULATED DEPRECIATION

| Line No. | Particulars | As at Dec. 31/11 | As at Dec. 31/10 | Increase Decrease |
|---|---|---|---|---|
| 1 | Intangible Plant | ($12,798,901) | ($10,260,451) | ($2,538,449) |
| 2 | Manufactured Gas Plant | 0 | 0 | 0 |
| 3 | Local Storage | (3,119,605) | 0 | (3,119,605) |
| 4 | Transmission | (136,493,679) | (125,077,439) | (11,416,240) |
| 5 | Distribution | (132,687,616) | (123,423,927) | (9,263,689) |
| 6 | General Plant | (8,907,820) | (8,492,265) | (415,555) |
| 7 | TOTAL ACCUMULATED DEPRECIATION | ($294,007,621) | ($267,254,082) | ($26,753,539) |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**ACCUMULATED DEPRECIATION**

| Line No. | Account | Mid-year 2011 GPIS for Depreciation | Annual Depreciation Rate % | Provision 2011 (Cr.) | Provision Adjust-ments | Provision Retirements | Accumulated 12/31/2010 | Accumulated 12/31/2011 |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 1 | **INTANGIBLE PLANT** | | | | | | | |
| 2 | 401-00 Franchise and Consents | $189,777 | 3.13% | $5,940 | $0 | $0 | $67,541 | $73,481 |
| 3 | 402-00 Other Intangible Plant | 1,219,037 | 2.30% | 28,038 | - | - | 592,479 | 620,517 |
| 4 | 461-00 Land Rights - Transmission | 7,201,345 | 0.00% | - | - | - | 1,099,673 | 1,099,673 |
| 5 | 471-00 Land Rights - Distribution | 1,865,911 | 0.00% | - | - | - | 235,485 | 235,485 |
| 6 | 402-00 Application Software - 8 year life | 16,009,704 | 12.50% | 1,946,682 | 5,151 | - | 7,474,596 | 9,426,430 |
| 7 | 402-00 Application Software - 5 year life | 2,905,652 | 20.00% | 552,638 | - | - | 790,677 | 1,343,315 |
| 8 | TOTAL INTANGIBLE PLANT | 29,391,425 | | 2,533,298 | 5,151 | - | 10,260,451 | 12,798,901 |
| 9 | **LOCAL STORAGE** | | | | | | | |
| 10 | 440 Land in Fee Simple | 540,910 | 0.00% | - | - | - | - | - |
| 11 | 441 Land Rights | 303,517 | 0.00% | - | - | - | - | - |
| 12 | 442 Structures & Improvements | 8,620,463 | 4.00% | 402,288 | - | - | - | 402,288 |
| 13 | 443 Gas Holders - Storage | 29,998,858 | 1.67% | 584,478 | - | - | - | 584,478 |
| 14 | 448 Piping (Mount Hayes) | 5,733,264 | 2.50% | 167,220 | - | - | - | 167,220 |
| 15 | 448 Pre-treatment (Mount Hayes) | 14,329,385 | 4.00% | 668,705 | - | - | - | 668,705 |
| 16 | 448 Liquefaction Equipment (Mount Hayes) | 14,329,385 | 2.50% | 417,940 | - | - | - | 417,940 |
| 17 | 448 Send Out Equipment (Mount Hayes) | 11,458,226 | 2.50% | 334,198 | - | - | - | 334,198 |
| 18 | 448 Sub-station (Mount Hayes) | 10,803,236 | 2.50% | 315,094 | - | - | - | 315,094 |
| 19 | 448 Control Room (Mount Hayes | 2,944,453 | 6.67% | 229,127 | - | - | - | 229,127 |
| 20 | 449 LNG Other Equipment | 16,601 | 2.86% | 554 | - | - | - | 554 |
| 21 | TOTAL LOCAL STORAGE | 99,078,297 | | 3,119,605 | - | - | - | 3,119,605 |
| 22 | **TRANSMISSION PLANT** | | | | | | | |
| 23 | 460-00 Land in Fee Simple | 3,020,086 | 0.00% | - | - | - | - | - |
| 24 | 462-00 Compressor Structures | 11,918,606 | 3.72% | 445,389 | 1,020 | - | 3,866,630 | 4,313,039 |
| 25 | 463-00 Measuring Structures | 7,543,861 | 2.87% | 216,408 | - | - | 2,665,401 | 2,881,809 |
| 26 | 464-00 Other Structures & Improvements | 129,522 | 2.87% | 3,717 | - | - | 20,154 | 23,871 |
| 27 | 465-00 Mains | 370,513,985 | 1.73% | 6,861,873 | (57,339) | (63,258) | 93,839,743 | 100,581,018 |
| 28 | 466-00 Compressor Equipment | 62,833,369 | 3.19% | 2,833,941 | 12,599 | - | 18,688,116 | 21,534,656 |
| 29 | 467-00 Measuring & Regulating Equipment | 17,661,050 | 5.59% | 1,003,806 | (629) | (63,803) | 3,904,586 | 4,843,960 |
| 30 | 468-00 Communication Structures & Equipment | 3,819,525 | 10.07% | 394,192 | 1,526 | (173,202) | 2,092,808 | 2,315,325 |
| 31 | TOTAL TRANSMISSION PLANT | 477,440,004 | | 11,759,327 | (42,823) | (300,263) | 125,077,438 | 136,493,679 |
| 32 | **DISTRIBUTION PLANT** | | | | | | | |
| 33 | 470 Land | 798,965 | 0.00% | - | - | - | - | - |
| 34 | -Frame Buildings | 2,382,940 | 3.21% | 74,232 | 176 | (2,806) | 941,745 | 1,013,346 |
| 35 | 473-00 Services | 177,067,094 | 1.91% | 3,350,774 | 22,523 | (143,764) | 37,262,109 | 40,491,641 |
| 36 | 474-00 House Regulator & Meter Installation | 23,475,341 | 3.45% | 802,556 | 3,992 | - | 6,074,280 | 6,880,828 |
| 37 | 475-00 Mains | 281,783,857 | 1.62% | 4,550,309 | 14,345 | (66,914) | 71,838,035 | 76,335,775 |
| 38 | -All Other | 63,920 | 0.00% | - | - | - | - | - |
| 39 | 477-00 Measuring & Regulating | 8,456,083 | 4.60% | 385,962 | 1,787 | (36,817) | 3,197,449 | 3,548,382 |
| 40 | 478 Meters | 13,695,828 | 4.37% | 605,220 | (297,887) | - | 4,110,310 | 4,417,643 |
| 41 | TOTAL DISTRIBUTION PLANT | 507,724,029 | | 9,769,052 | (255,064) | (250,301) | 123,423,928 | 132,687,616 |
| 42 | **GENERAL PLANT & EQUIPMENT** | | | | | | | |
| 43 | 480-00 Land in Fee Simple | 1,267,975 | 0.00% | - | - | - | - | - |
| 44 | 482-00 Structures & Improvements | 5,640,583 | 4.36% | 323,312 | - | (1,414) | 1,135,463 | 1,457,361 |
| 45 | - Furniture & Equipment | 842,444 | 6.67% | (46,394) | - | (291,747) | 524,968 | 186,828 |
| 46 | - Computer Hardware | 2,381,919 | 20.00% | 255,089 | 4,551 | (155,459) | 707,043 | 811,224 |
| 47 | - Computer Software | 346,161 | 20.00% | 59,069 | - | (2,946) | 127,725 | 183,848 |
| 48 | 484-00 Transportation Equipment | 5,137,292 | 17.88% | 873,017 | - | (363,451) | 1,897,127 | 2,406,693 |
| 49 | 485-00 Heavy Work Equipment | 1,460,879 | 6.34% | 105,766 | - | (39,720) | 310,719 | 376,765 |
| 50 | 486-00 Small Tools & Equipment | 6,687,309 | 7.35% | 336,874 | - | (526,352) | 3,328,495 | 3,139,017 |
| 51 | - Telephone | 658,835 | 6.67% | 41,380 | - | (156,021) | 460,725 | 346,085 |
| 52 | TOTAL GENERAL PLANT | 24,423,397 | | 1,948,114 | 4,551 | (1,537,109) | 8,492,265 | 8,907,820 |
| 53 | **TOTAL** | $ 1,138,057,152 | | $ 29,129,396 | $ (288,185) | $ (2,087,673) | $ 267,254,082 | $ 294,007,621 |
| 54 | Less: Vehicle Depreciation allocated to capital projects | | | (312,150) | | | | |
| 55 | **Net Depreciation Expense** | | | $28,817,247 | | | | |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **4.0.0**
**ANNUAL REPORT - 2011**
**GAS ACCOUNT**
**GJs of Gas as Measured**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | GAS RECEIVED [1] | | | |
| 1 | Natural Gas Purchases | 12,562,549 | 11,504,537 | 1,058,012 |
| 2 | Natural Gas for Transportation | 8,367,643 | 19,526,346 | (11,158,703) |
| 3 | Total Receipts | 20,930,192 | 31,030,883 | (10,100,691) |
| | GAS DELIVERED | | | |
| 4 | Sales to Ultimate Customers | 12,547,590 | 11,491,394 | 1,056,196 |
| 5 | Deliveries to Transportation Customers | 8,367,643 | 19,526,346 | (11,158,703) |
| 6 | Total Deliveries | 20,915,233 | 31,017,740 | (10,102,507) |
| 7 | Gas Receipts less Gas Deliveries | 14,959 | 13,143 | 1,816 |
| 8 | Unaccounted as a percent of Purchases | 0.12% | 0.11% | 0.00 |
| 9 | Cost of Gas Sold ($) | $82,027,685 | $74,343,207 | $7,684,478 |
| 10 | Averaged Cost of Gas Sold ($/GJ) | $6.54 | $6.47 | $0.07 |

[1] Excluding own use gas.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**ACTUAL GAS SALES, REVENUE AND CUSTOMERS**

| | | Residential | | Commercial | | Industrial | | Total | |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | Particulars | $ | GJ | $ | GJ | $ | GJ | $ | GJ |
| | GAS SALES & REVENUE | | | | | | | | |
| | Distribution: | | | | | | | | |
| 1 | 2011 | $84,953,353 | 5,142,503 | $99,257,359 | 7,405,087 | $0 | 0 | $184,210,712 | 12,547,590 |
| 2 | 2010 | $76,335,369 | 4,547,786 | $93,454,127 | 6,943,608 | $0 | 0 | $169,789,496 | 11,491,394 |
| 3 | Increase/Decrease | $8,617,984 | 594,717 | $5,803,232 | 461,479 | $0 | 0 | $14,421,216 | 1,056,196 |
| | Transportation:[1] | | | | | | | | |
| 4 | 2011 | $0 | 0 | $0 | 0 | $24,038,729 | 8,367,643 | $24,038,729 | 8,367,643 |
| 5 | 2010 | 0 | 0 | 0 | 0 | $23,620,718 | 19,526,346 | $23,620,718 | 19,526,346 |
| 6 | Increase/Decrease | $0 | 0 | $0 | 0 | $418,011 | (11,158,703) | $418,011 | (11,158,703) |

| | | Residential | | Commercial | | Industrial | | Total | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| | CUSTOMERS | | | | | | | | |
| | Distribution: | | | | | | | | |
| 7 | Year End | 92,554 | 90,671 | 9,548 | 9,465 | 0 | 0 | 102,102 | 100,136 |
| 8 | Average | 91,613 | 89,496 | 9,507 | 9,424 | 0 | 0 | 101,119 | 98,920 |
| | Transportation: | | | | | | | | |
| 9 | Year End | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 |
| 10 | Average | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 |

[1] Transportation volumes include 739,844 GJs of intercompany wheeling with FEW in 2011 and 753,195 GJs of intercompany wheeling with FEW in 2010.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## OTHER REVENUE



| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | OTHER REVENUE | | | |
| 1 | Connection Charges | $329,604 | $391,475 | ($61,871) |
| 2 | NSF Cheque Charges | 5,880 | 5,400 | 480 |
| 3 | Penalty Revenue | 361,584 | 295,481 | 66,103 |
| 4 | Royalty Income | 15,302,854 | 17,215,110 | (1,912,256) |
| 5 | LNG Mitigation Revenue from FEI | 11,959,992 | - | 11,959,992 |
| 6 | FEVI LNG Costs tsf'd to Commodity | 1,576,575 | - | 1,576,575 |
| 7 | Miscellaneous | (23,164) | (2,774) | (20,390) |
| 8 | Total Other Revenue | $29,513,325 | $17,904,692 | $11,608,633 |

| Line No. | Particulars | 2011 | 2010 |
|---|---|---|---|
| | Royalty Income | | |
| 9 | Current year Royalty Income | $13,290,162 | $13,640,393 |
| 10 | Prior year adjustment in the current year | 2,012,692 | 3,574,717 |
| 11 | Current year per financial statements | $15,302,854 | $17,215,110 |
| 12 | Prior year as previously stated | $13,640,393 | $21,088,762 |
| 13 | Prior year adjustment | 2,012,692 | 3,574,717 |
| 14 | Prior year restated | $15,653,085 | $24,663,479 |

## FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## OPERATING & MAINTENANCE EXPENSES - SUMMARY

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Total Gross O&M Expenses | $31,521,839 | $29,852,121 | $1,669,718 |
| 2 | Difference from Allowed O&M Expenses | (1,180,161) | (1,378,879) | 198,718 |
| 3 | TOTAL GROSS O&M EXPENSES ALLOWED | $32,702,000 | $31,231,000 | $1,471,000 |
| 4 | Capitalization Allowed | (4,566,394) | (4,372,368) | (194,026) |
| 5 | TOTAL NET DIRECT O&M EXPENSES ALLOWED | $28,135,606 | $26,858,632 | $1,276,974 |
| 6 | Average Full Time Employee Count | 109.31 | 100.74 | 8.57 |

RECONCILIATION OF FINANCIAL STATEMENT O&M EXPENSE

| Line No. | Particulars | 2011 | 2010 |
|---|---|---|---|
| 7 | TOTAL NET DIRECT O&M EXPENSES ALLOWED (as per above line 5) | $28,135,606 | $26,858,632 |
| 8 | Compressor Lease (non-O&M) | - | - |
| 9 | Difference from Allowed O&M Expenses (as per above line 2) | (1,180,161) | (1,378,879) |
| 10 | Add: Removal Cost | 344,004 | 342,816 |
| 11 | Add: Non-Regulatory Provisions | 0 | 588,263 |
| 12 | TOTAL O&M EXPENSE per Financial Statements | $27,299,449 | $26,410,832 |

**ANNUAL REPORT - 2011**

**OPERATING AND MAINTENANCE EXPENSES (Resource View)**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| 1 | M&E Costs | $ 3,475,374 | $ 3,569,754 | $ (94,380) |
| 2 | COPE Costs | 407,153 | 247,692 | 159,461 |
| 3 | IBEW Costs | 5,207,011 | 4,644,220 | 562,791 |
| 4 | **Labour Costs** | **9,089,537** | **8,461,666** | **627,871** |
| 5 | Vehicle costs | 588,036 | 606,364 | (18,327) |
| 6 | Employee Expenses | 537,559 | 568,071 | (30,512) |
| 7 | Materials and Supplies | 1,227,674 | 1,103,339 | 124,335 |
| 8 | Office Furnishing & Equipment | 9,122 | 19,231 | (10,109) |
| 9 | Computer Costs | 326,459 | 529,114 | (202,654) |
| 10 | Fees and Administration Costs | 12,438,516 | 11,465,465 | 973,051 |
| 11 | Contractors costs | 6,077,803 | 6,204,736 | (126,933) |
| 12 | Facilities | 2,248,243 | 2,047,080 | 201,163 |
| 13 | Recoveries & Revenue | (1,021,110) | (1,152,944) | 131,834 |
| 14 | **Non-Labour Costs** | **22,432,302** | **21,390,455** | **1,041,848** |
| 15 | **Total Gross O&M Expense** | **$ 31,521,839** | **$ 29,852,121** | **$ 1,669,718** |

**OPERATING AND MAINTENANCE EXPENSES (Activity View)**

| Line No. | Particulars | Reference | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| | **OPERATING** | | | | |
| 1 | Distribution Supervision | 100-11 | $ 1,942,972 | $ 1,826,630 | $ 116,342 |
| 2 | Distribution Supervision Total | 100-10 | 1,942,972 | 1,826,630 | 116,342 |
| 3 | Operation Centre - Distribution | 100-21 | 602,986 | 443,454 | 159,533 |
| 4 | Preventative Maintenance - Distribution | 100-23 | 143,415 | 193,136 | (49,721) |
| 5 | Distribution Operations - General | 100-24 | 1,173,583 | 1,068,717 | 104,867 |
| 6 | Emergency Management | 100-26 | 1,021,629 | 820,179 | 201,450 |
| 7 | Distribution Operations Total | 100-20 | 2,941,614 | 2,525,486 | 416,128 |
| 8 | Distribution Corrective - Meters | 100-31 | 204,802 | 300,783 | (95,981) |
| 9 | Distribution Corrective - Leak Repair | 100-33 | 100,395 | 85,660 | 14,735 |
| 10 | Distribution Corrective - Stations | 100-34 | 13,658 | 12,752 | 906 |
| 11 | Distribution Corrective - General | 100-35 | 47,832 | 67,996 | (20,164) |
| 12 | Distribution Maintenance Total | 100-30 | 366,688 | 467,191 | (100,503) |
| 13 | **Distribution Total** | **100** | **5,251,274** | **4,819,307** | **431,967** |
| 14 | Transmission Supervision | 200-11 | 353,999 | - | 353,999 |
| 15 | Transmission Supervision Total | 200-10 | 353,999 | **-** | **353,999** |
| 16 | Pipeline Operation - Operations | 200-21 | 520,478 | 1,316,301 | (795,823) |
| 17 | Right of Way | 200-22 | 453,844 | 113,842 | 340,002 |
| 18 | Compression - Operations | 200-23 | 718,047 | 919,463 | (201,416) |
| 19 | Transmission Pipeline Integrity Project (TPIP) | 200-25 | 162,124 | | 162,124 |
| 20 | Transmission - Operation | 200-20 | 1,854,494 | 2,349,606 | (495,112) |
| 21 | Pipeline Operation - Maintenance | 200-31 | 104,946 | 490,079 | (385,133) |
| 22 | Compression - Maintenance | 200-32 | 406,470 | 715,512 | (309,042) |
| 23 | TPIP - Maintenance | 200-33 | 80,266 | - | 80,266 |
| 24 | Transmission - Maintenance | 200-30 | 591,682 | 1,205,591 | (613,909) |
| 25 | **Transmission Total** | **200** | **2,800,175** | **3,555,197** | **(755,022)** |
| 26 | LNG Plant Operation | 300-10 | 1,584,672 | 438,097 | 1,146,576 |
| 27 | **LNG Total** | **300** | **1,584,672** | **438,097** | **1,146,575** |
| 28 | Measurement Operations | 400-11 | 486,526 | 459,388 | 27,138 |
| 29 | Measurement - Operation | 400-10 | 486,526 | 459,388 | 27,138 |
| 30 | Measurement Maintenance | 400-21 | 364,890 | 457,259 | (92,369) |
| 31 | Measurement - Maintenance | 400-20 | 364,890 | 457,259 | (92,369) |
| 32 | **Measurement Total** | **400** | **851,416** | **916,647** | **(65,231)** |
| 33 | Facilities Management | 500-10 | 1,590,373 | 1,459,732 | 130,641 |
| 34 | Operations Engineering | 500-30 | 698,834 | 749,927 | (51,093) |
| 35 | System Integrity | 500-50 | 114,710 | 119,407 | (4,697) |
| 36 | **General Operations Total** | **500** | **2,403,916** | **2,329,066** | **74,850** |
| 37 | **TOTAL OPERATING** | | **12,891,453** | **12,058,314** | **833,139** |
| | **GENERAL & ADMINISTRATION** | | | | |
| 38 | Corporate & Marketing Communications | 600-30 | 53,545 | 136,652 | (83,107) |
| 39 | **Marketing Total** | **600** | **53,545** | **136,652** | **(83,107)** |
| 40 | Customer Contact - ABSU contract | 700-20 | 5,233,322 | 4,890,845 | 342,477 |
| 41 | Bad Debt Management and Administration | 700-30 | 286,861 | 312,363 | (25,502) |
| 42 | Customer Management & Sales | 700-40 | 1,129,966 | 1,094,705 | 35,261 |
| 43 | **Customer Care Total** | **700** | **6,650,148** | **6,297,913** | **352,235** |
| 44 | Application Management | 800-20 | 413,252 | 387,435 | 25,817 |
| 45 | **Business & IT Services Total** | **800** | **413,252** | **387,435** | **25,817** |
| 46 | Administration & General - inc insurance | 900-11 | 453,996 | 232,365 | 221,631 |
| 47 | Insurance | 900-12 | 904,441 | 861,000 | 43,441 |
| 48 | Finance and Regulatory Affairs | 900-13 | 430,569 | 381,175 | 49,393 |
| 49 | Shared Services | 900-14 | 8,638,000 | 8,326,000 | 312,000 |
| 50 | Corporate Administration Total | 900-10 | 10,427,006 | 9,800,540 | 626,467 |
| 51 | Community Relations | 900-31 | 245,996 | 234,267 | 11,729 |
| 52 | Public Affairs | 900-30 | 245,996 | 234,267 | 11,729 |
| 53 | Human Resources | 900-50 | 438 | - | 438 |
| 54 | Other Post Employment Benefits | 900-60 | 840,000 | 937,000 | (97,000) |
| 55 | **Administration & General Total** | **900** | **11,513,441** | **10,971,807** | **541,634** |
| 56 | **TOTAL GENERAL AND ADMINISTRATION** | | **18,630,386** | **17,793,807** | **836,579** |
| 57 | **Total Gross O&M Expense** | | **$ 31,521,839** | **$ 29,852,121** | **$ 1,669,718** |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **6.0.0**
**ANNUAL REPORT - 2011**
**PIPELINE METRES**

| Line No. | Pipe Size mm | 2011 Plastic | Steel | HP/TP Steel Mains | MOPP | P. Sys Bet. | Total |
|---|---|---|---|---|---|---|---|
| 1 | 33-44 | 1,357,407 | 15,495 | 0 | 90,752 | 26,029 | 1,489,683 |
| 2 | 60 | 863,855 | 100,269 | 0 | 32,257 | 15,055 | 1,011,436 |
| 3 | 88 | 419,841 | 5,534 | 19,252 | 5,456 | 4,858 | 454,941 |
| 4 | 114 | 243,204 | 42,456 | 67,639 | 2,562 | 16,541 | 372,402 |
| 5 | 168 | 102,423 | 16,378 | 72,108 | 0 | 4,710 | 195,619 |
| 6 | 219 | 0 | 52,758 | 68,265 | 0 | 4,167 | 125,190 |
| 7 | 273 | 0 | 0 | 504,768 | 0 | 0 | 504,768 |
| 8 | 323 | 0 | 0 | 45,875 | 0 | 602 | 46,477 |
| 9 | Total | 2,986,730 | 232,890 | 777,907 | 131,027 | 71,962 | 4,200,516 |

| Line No. | Pipe Size mm | 2010 Plastic | Steel | HP/TP Steel Mains | MOPP | P. Sys Bet. | Total |
|---|---|---|---|---|---|---|---|
| 10 | 33-44 | 1,352,691 | 15,495 | 0 | 90,752 | 26,587 | 1,485,525 |
| 11 | 60 | 846,722 | 100,269 | 0 | 32,257 | 14,862 | 994,111 |
| 12 | 88 | 419,841 | 5,534 | 19,252 | 5,456 | 5,105 | 455,188 |
| 13 | 114 | 238,853 | 42,376 | 61,749 | 2,562 | 16,071 | 361,611 |
| 14 | 168 | 102,423 | 16,378 | 72,048 | 0 | 4,703 | 195,552 |
| 15 | 219 | 0 | 52,758 | 68,285 | 0 | 4,167 | 125,210 |
| 16 | 273 | 0 | 0 | 500,520 | 0 | 0 | 500,520 |
| 17 | 323 | 0 | 0 | 45,855 | 0 | 602 | 46,457 |
| 18 | Total | 2,960,530 | 232,810 | 767,709 | 131,027 | 72,097 | 4,164,174 |

| | | 2011 ADDITIONS Plastic | Steel | HP/TP Steel Mains | MOPP | P. Sys Bet. | Total |
|---|---|---|---|---|---|---|---|
| 19 | 33-44 | 4,716 | 0 | 0 | 0 | (558) | 4,157 |
| 20 | 60 | 17,133 | 0 | 0 | 0 | 193 | 17,326 |
| 21 | 88 | 0 | 0 | 0 | 0 | (247) | (247) |
| 22 | 114 | 4,351 | 80 | 5,890 | 0 | 470 | 10,791 |
| 23 | 168 | 0 | 0 | 60 | 0 | 8 | 68 |
| 24 | 219 | 0 | 0 | (20) | 0 | 0 | (20) |
| 25 | 273 | 0 | 0 | 4,248 | 0 | 0 | 4,248 |
| 26 | 323 | 0 | 0 | 20 | 0 | 0 | 20 |
| 27 | Total | 26,200 | 80 | 10,198 | 0 | (135) | 36,343 |

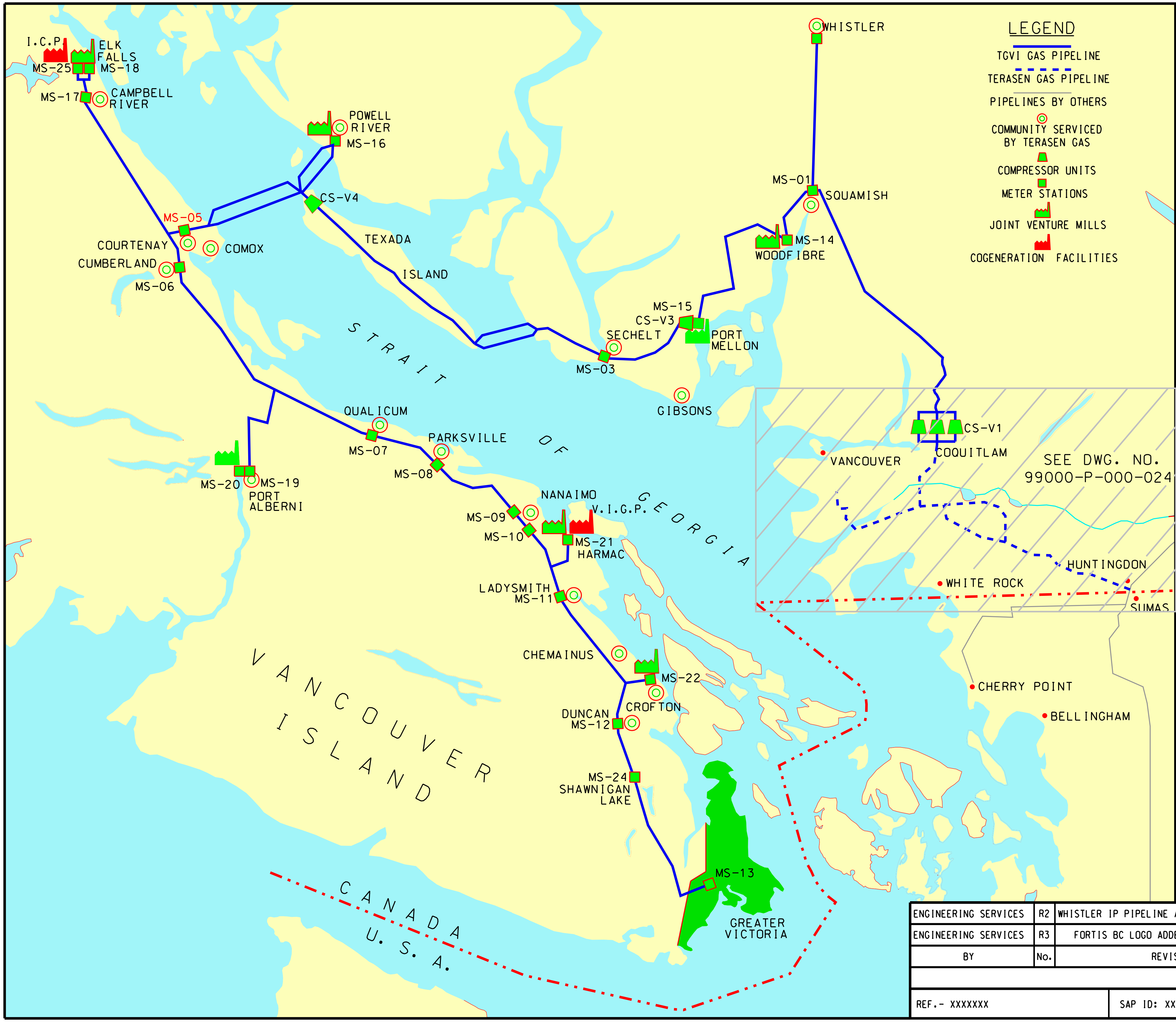
# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
# ANNUAL REPORT - 2011
# SERVICE INTERRUPTIONS AND PROPERTY DAMAGE

## 1. Service Interruptions

There were no significant system interruptions to report in 2011.

## 2. Damage/Injury

There were no significant property and personal injury claims to report in 2011.




# FORTIS BC (VANCOUVER ISLAND) NATURAL GAS SYSTEM MAP

## PIPELINE SYSTEM

**OVERLAND - MAIN PIPELINES**

31.571 km of 12" (323.9 mm) O.D. ON MAINLAND
132.048 km of 10" (273.1 mm) O.D. ON MAINLAND
50.145 km of 10" (273.1 mm) O.D. ON TEXADA ISLAND
216.824 km of 10" (273.1 mm) O.D. ON VANCOUVER ISLAND (MAINLINE)
430.588 km

**MARINE PIPELINES**

12.278 km of 10" (273.1 mm) O.D. SECRET COVE NORTH
12.270 km of 10" (273.1 mm) O.D. SECRET COVE SOUTH
10.900 km of 10" (273.1 mm) O.D. POWELL RIVER NORTH
10.957 km of 10" (273.1 mm) O.D. POWELL RIVER SOUTH
23.679 km of 10" (273.1 mm) O.D. LITTLE RIVER NORTH
23.670 km of 10" (273.1 mm) O.D. LITTLE RIVER SOUTH
93.754 km

**EXTENSION PIPELINES**

0.717 km of 4" (114.3 mm) O.D. PT. MELLON EXTENSION
0.495 km of 4" (114.3 mm) O.D. WOODFIBRE EXTENSION
1.060 km of 4" (114.3 mm) O.D. POWELL RIVER EXTENSION
1.853 km of 6" (168.3 mm) O.D. PT. ALBERNI MILL EXTENSION
4.125 km

**LATERALS**

49.532 km of 8" (219.1 mm) O.D. CAMPBELL RIVER LATERAL
21.696 km of 6" (168.3 mm) O.D. PT. ALBERNI LATERAL
5.092 km of 6" (168.3 mm) O.D. CROFTON LATERAL
9.720 km of 6" (168.3mm) O.D. HARMAC LATERAL
86.040 km

**TOTALS**

430.588 km of OVERLAND PIPELINES (10" & 12")
93.754 km of MARINE PIPELINES (10")
90.165 km of LATERALS & EXTENSIONS (4",6" & 8")
614.507 km of TOTAL PIPELINES

**NOTE:**

LENGTHS OF PIPELINES ARE APPROX. ONLY

| | | | | | | |
|---|---|---|---|---|---|---|
| ENGINEERING SERVICES | R2 | WHISTLER IP PIPELINE ADDED | W KUMPULA | | | 09-07-26 |
| ENGINEERING SERVICES | R3 | FORTIS BC LOGO ADDED | FSEDLAR | | | 11-03-01 |
| BY | No. | REVISION | DRAWN | DESIGNED | CHECKED | DATE(YY-MM-DD) |
| | | | MICROFILMED | | | SCALE- AS SHOWN |

| | | |
|---|---|---|
| REF.- XXXXXXX | SAP ID: XXXXXXXXXX | DRAWING No. 96000-P-000-101-R2 |

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## WORKING CAPITAL REQUIREMENTS

| Line No. | Particulars | Reference | 2011 | 2010 |
|---|---|---|---|---|
| 1 | Cash Working Capital Requirements[1] | 9.1.0 | $2,254,462 | $2,067,783 |
| | Inventory: | | | |
| 2 | Gas in Storage | 9.2.0 | 10,442,932 | 10,717,417 |
| 3 | Withholdings From Employees | 9.2.0 | (323,984) | (243,241) |
| 4 | Refundable Contributions | 9.2.0 | (289,301) | (289,033) |
| 5 | Reserve for Bad Debts | 9.2.0 | (1,137,443) | (890,372) |
| 6 | Sub-Total | | $8,692,204 | $9,294,771 |
| | Deferred Expenses, Mid-Year: | 1.8.0 | | |
| 7 | Gas Cost Variance Account | | ($2,126,619) | ($1,041,166) |
| 8 | Energy Efficiency & Conservation (EEC) | | 2,010,552 | 639,863 |
| 9 | Olympic Security Costs | | 111,226 | 85,185 |
| 10 | IFRS Conversion Costs | | 82,492 | 63,029 |
| 11 | 2010-2011 Revenue Requirement Costs | | 63,162 | 146,941 |
| 12 | 2012-2013 Revenue Requirement Costs | | 43,598 | - |
| 13 | 2009 ROE Capital Structure Costs | | 49,457 | 63,620 |
| 14 | CCE CPCN Application Costs | | 23,077 | 24,797 |
| 15 | Victoria Regional Centre CPCN Application | | 24,534 | 6,032 |
| 16 | PCEC Start Up Costs | | 1,073,730 | 1,117,630 |
| 17 | IFRS Transitional Deferral | | 387,225 | 191,187 |
| 18 | Pension & OPEB Funding | | (4,309,873) | (2,257,186) |
| 19 | Gains / Losses on Asset Disposition | | 1,150,011 | 330,019 |
| 20 | Deferred Removal Costs | | 490,098 | 162,321 |
| 21 | Vancouver Island HST Implementation | | (78,924) | (24,268) |
| 22 | US GAAP Conversion Costs | | 32,351 | - |
| 23 | Compressor Fired Hours | | - | (491,972) |
| 24 | LNG | | - | 205,560 |
| 25 | VIGP (Duke Point) | | - | 3,706 |
| 26 | Financing Costs | | - | 1,088,411 |
| 27 | Preliminary Survey & Investigation Costs | | - | 17,981 |
| 28 | Sub-Total | | ($973,903) | $331,690 |
| 29 | TOTAL WORKING CAPITAL REQUIREMENTS | | $9,972,763 | $11,694,244 |

[1] 2010 figures have been restated.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## CASH WORKING CAPITAL REQUIREMENTS

| Line No. | Particulars | Reference | Days | Expenses | Working Capital |
|---|---|---|---|---|---|
| | CASH WORKING CAPITAL | | | | |
| 1 | Revenue Lag Days | | 39.5 | | |
| 2 | Expenses Lead Days | | 33.9 | | |
| 3 | Net Lead/(Lag) Days | | 5.6 | $146,315,181 | $2,254,462 |

| Line No. | Particulars | Reference | Revenue | Lag Days Service to Collection | Dollar Days |
|---|---|---|---|---|---|
| | REVENUE | | | | |
| 4 | Gas Sales and Transporation Service Revenue | | | | |
| 5 | Residential and Commercial | 4.1.0 | $184,210,712 | 38.7 | $7,128,954,554 |
| 6 | T-Service | 4.1.0 | 24,038,729 | 38.4 | 923,087,194 |
| 7 | Total Gas Sales | | 208,249,441 | 38.7 | 8,052,041,748 |
| 8 | Other Revenues | | | | |
| 9 | Late Payment Charges | 4.2.0 | 361,584 | 38.9 | 14,065,618 |
| 10 | Returned Cheque Charges | 4.2.0 | 5,880 | 38.9 | 228,732 |
| 11 | Connection Charges | 4.2.0 | 329,604 | 38.9 | 12,821,596 |
| 12 | Royalty Revenue | 4.2.0 | 15,302,854 | 45.6 | 697,810,142 |
| 13 | LNG Mitigation Revenue from FEI | 4.2.0 | 11,959,992 | 45.6 | 545,375,635 |
| 14 | FEVI LNG Costs tsf'd to Commodity | 4.2.0 | 1,576,575 | 45.6 | 71,891,820 |
| 15 | Miscellaneous | 4.2.0 | (23,164) | 38.9 | (901,080) |
| 16 | Total Revenue | | $237,762,766 | 39.5 | $9,393,334,211 |

| Line No. | Particulars | Reference | Expense | Lead Days Expense to Payment | Dollar Days |
|---|---|---|---|---|---|
| | EXPENSES | | | | |
| 17 | Gas Purchases | 4.0.0 | $82,027,685 | 40.2 | $3,297,512,929 |
| 18 | Less: Gas Cost Variance Account (GCVA) | 1.8.0 | (8,764,546) | 40.2 | (352,334,749) |
| 19 | | | 73,263,139 | 40.2 | 2,945,178,180 |
| 20 | Transportation Costs | 10.0.0 | 3,771,532 | 40.2 | 151,615,605 |
| 21 | O&M Expenses | 5.0.0 | 28,135,606 | 35.8 | 1,007,254,695 |
| 22 | Taxes Other than Income | | | | |
| 23 | Municipal Taxes | 10.0.0 | 9,311,870 | 2.6 | 24,210,862 |
| 24 | Carbon Tax | | 13,791,212 | 29.5 | 406,840,752 |
| 25 | HST | | 6,027,827 | 39.8 | 239,907,506 |
| 26 | Income Tax | 10.1.0 | 12,013,995 | 15.2 | 182,612,722 |
| 27 | Total Expenses | | $146,315,181 | 33.9 | $4,957,620,321 |

FORTISBC ENERGY (VANCOUVER ISLAND) INC. 
ANNUAL REPORT - 2011
WORKING CAPITAL REQUIREMENTS - 13 MONTH AVERAGE

| Line No. | Particulars | 2011 Y/E Balance | 2011 13 Month Average | 2010 Y/E Balance | 2010 13 Month Average |
|---|---|---|---|---|---|
| 1 | Gas in Storage | $12,521,220 | $10,442,932 | $10,455,131 | $10,717,417 |
| 2 | Withholdings From Employees | ($250,712) | ($323,984) | ($186,956) | ($243,241) |
| 3 | Refundable Contributions | ($288,947) | ($289,301) | ($288,900) | ($289,033) |
| 4 | Reserve for Bad Debt | ($1,261,481) | ($1,137,443) | ($913,388) | ($890,372) |

## FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## EARNED RETURN



| Line No. | Particulars | Reference | 2011 | 2010 |
|---|---|---|---|---|
| 1 | Gas Sales (GJ) | 4.0.0 | 12,547,590 | 11,491,394 |
| 2 | Gas Revenue at Existing Rates | 4.1.0 | $184,210,712 | $169,789,496 |
| 3 | Cost of Gas | 4.0.0 | 82,027,685 | 74,343,207 |
| 4 | GROSS MARGIN REVENUE | | $102,183,027 | $95,446,289 |
| 5 | Transportation Revenue | 4.1.0 | 24,038,729 | 23,620,718 |
| 6 | Other Revenue | 4.2.0 | 29,513,325 | 17,904,692 |
| 7 | TOTAL REVENUE | | $155,735,081 | $136,971,699 |
| 8 | Operating Expenses | 5.0.0 | $28,135,606 | $26,858,632 |
| 9 | Transportation Costs | 9.1.0 | 3,771,532 | 4,019,245 |
| 10 | Municipal taxes | 9.1.0 | 9,311,870 | 9,039,046 |
| 11 | Depreciation Expense | 3.1.0 | 28,817,247 | 25,974,706 |
| 12 | Amortization of CIAC | 2.5.0 | (4,427,894) | (4,420,493) |
| 13 | Amortization of Deferreds | 1.8.0 | 1,123,084 | (584,576) |
| 14 | Amortization of Gas Cost Variance Account | 1.8.0 | 3,282,074 | (5,624,745) |
| 15 | Amortization of 2009 Revenue Surplus | 1.8.0 | (1,481,000) | (1,481,000) |
| 16 | Removal Costs | | 344,004 | 342,816 |
| 17 | IFRS Revenue Requirement Adjustment | | (1,400,000) | 1,400,000 |
| 18 | Revenue Surplus Deferred[1] | | 28,577,478 | 31,693,021 |
| 19 | Interest on Subordinated Debt | | 0 | 261,281 |
| 20 | TOTAL EXPENSES | | $96,054,000 | $87,477,934 |
| 21 | Utility Earned Return before Taxes | | $59,681,081 | $49,493,765 |
| 22 | Total Taxes Payable[1] | 10.1.0 | 12,013,995 | 12,911,947 |
| 23 | | | $47,667,086 | $36,581,818 |
| 24 | Calculated Earned Return[1] | 12.0.0 | $49,534,086 | $38,448,818 |
| 25 | Less: Special Direction Provision | | 1,867,000 | 1,867,000 |
| 26 | ALLOWED EARNED RETURN | | $47,667,086 | $36,581,818 |
| 27 | UTILITY RATE BASE1 | 11.0.0 | $666,114,363 | $547,565,519 |
| 28 | Return on Rate Base %[1] | | 7.16% | 6.68% |
| 29 | Allowed Return %[1] | 12.0.0 | 7.44% | 7.02% |
| 30 | Variance | | -0.28% | -0.34% |

[1] 2010 figures have been restated.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **10.1.0**
**ANNUAL REPORT - 2011**
**INCOME TAXES**

| Line No. | Particulars | Reference | 2011 | 2010 |
|---|---|---|---|---|
| 1 | Utility Earned Return after Taxes[1] | 12.0.0 | $49,534,086 | $38,448,818 |
| 2 | Less: Special Direction Provision | 10.0.0 | (1,867,000) | (1,867,000) |
| 3 | Add: Variance in OM&A expenses | 5.0.0 | 1,180,161 | 1,378,879 |
| 4 | Less: Financing Expenses[1] | 12.0.0 | (22,889,511) | (16,546,197) |
| 5 | Achieved Return on Equity for Tax Purpose | | $25,957,736 | $21,414,500 |
| | Add: | | | |
| 6 | Revenue Surplus Deferred - Current Year[1] | 10.0.0 | $28,577,478 | $31,693,021 |
| 7 | Depreciation | 3.1.0 | 28,817,247 | 25,974,706 |
| 8 | Amortization of CIAC | 2.5.0 | (4,427,894) | (4,420,493) |
| 9 | Amortization of Deferreds | 1.8.0 | 2,924,158 | (7,690,321) |
| 10 | Non Allowable Portion of Club Dues | | 3,245 | 0 |
| 11 | Non Allowable Portion of Meals & Entertainment | | 98,151 | 59,976 |
| 12 | Non-deductible Reserve | | 0 | 273,159 |
| 13 | Pension/ Post Retirement Expensed In Accounts | | 1,863,000 | 2,345,000 |
| 14 | Taxable Capital gain | | 0 | 21,400 |
| 15 | HST Savings | | 12,338 | 0 |
| 16 | IFRS Revenue Requirement Adjustment | | (1,400,000) | 1,400,000 |
| 17 | Total Additions | | $56,467,722 | $49,656,449 |
| | Deduct: | | | |
| 18 | Capital Cost Allowance | 10.1.1 | $39,532,258 | $29,165,711 |
| 19 | Cumulative Eligible Capital Deduction | | 384,768 | 353,829 |
| 20 | AFUDC Capitalized in Accounts[1] | | 2,444,794 | 3,473,698 |
| 21 | Indirect Overheads Capitalized in the Accounts | | 2,935,539 | 2,810,808 |
| 22 | Allowable Portion of Financing Expenses per ITA 20(1)(e) | | 313,642 | 495,454 |
| 23 | Deductible Inspections Costs | | 0 | 544,069 |
| 24 | Pension/Post Retirement Contributions | | 2,875,274 | 1,638,145 |
| 25 | O&M Adjustment - Prior Year | | 300,000 | 0 |
| 26 | Total Deductions | | $48,786,275 | $38,481,714 |
| 27 | Net Income (Loss) for Tax Purposes | | $33,639,183 | $32,589,235 |
| 28 | Charitable Donations Utilized | | 0 | 0 |
| | Non-Capital Loss Carry Forward Utilized | | 0 | 0 |
| 29 | TAXABLE INCOME AFTER TAX | | $33,639,183 | $32,589,235 |
| 30 | Tax Gross-Up | | 73.50% | 71.50% |
| 31 | TAXABLE INCOME | | $45,767,596 | $45,579,350 |
| 32 | Federal Tax[1] | 26.00% | $11,899,575 | $12,762,218 |
| 33 | Less: Tax Abatement[1] | 10.00% | 4,576,760 | 4,557,935 |
| 34 | Net Federal Tax | | $7,322,815 | $8,204,283 |
| 35 | Federal Surcharge | 0.00% | $0 | $0 |
| 36 | Provincial Tax[1] | 10.50% | 4,805,598 | 4,785,832 |
| 37 | Income Tax Expense | 26.50% | $12,128,413 | $12,990,115 |
| 38 | Less Federal Surcharge offset by LCT | 0.00% | 0 | 0 |
| 39 | Net Income Tax Expense | 26.50% | $12,128,413 | $12,990,115 |
| 40 | Previous Year Adjustment | | (114,418) | (78,168) |
| 41 | Total Income Tax Expense | | $12,013,995 | $12,911,947 |

[1] 2010 figures have been restated.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **10.1.1**
**ANNUAL REPORT - 2011**
**UCC CONTINUITY - REGULATORY PURPOSES (Customer)**

**Year Ended December 31, 2011**

| Line | Description | Class | Rate | (1) Jan 1, 2011 UCC Opening | (2) Opening Adjustments | (3) Cost of Net Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) UCC Balance | (7) 1/2 of (3)-(4)+(5) | (8) UCC available for CCA | (9) CCA | (10) Dec 31, 2011 UCC Closing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $283,821,751 | | $0 | | | $283,821,751 | $0 | $283,821,751 | $11,352,870 | $272,468,881 |
| 2 | Building and Utility - post March 19, 2007 | 1.3 | 6% | $5,199,307 | | $6,251,885 | | | $11,451,192 | $3,125,943 | $8,325,250 | $556,756 | $10,894,436 |
| 3 | Utility Plant - pre 88 | 2 | 6% | $6,689,097 | | - | | | 6,689,097 | - | 6,689,097 | 401,346 | 6,287,752 |
| 4 | Building - post 87 | 3 | 5% | $135,611 | | - | | | 135,611 | - | 135,611 | 6,781 | 128,830 |
| 5 | Buildings Portable | 6 | 10% | $5,691 | | - | | | 5,691 | - | 5,691 | 569 | 5,122 |
| 6 | Trans Pipe Comp Equip | 7 | 15% | $16,293,627 | | $864,064 | | | 17,157,691 | 432,032 | 16,725,659 | 2,508,849 | 14,648,842 |
| 7 | F&F/Commun Equip - post 76 | 8 | 20% | $6,084,927 | | 854,318 | | | 6,939,245 | 427,159 | 6,512,086 | 1,302,417 | 5,636,828 |
| 8 | Commun Equip - pre 77 | 9 | 25% | $1 | | - | | | 1 | - | 1 | 0 | 1 |
| 9 | Vehicles/Comp Equip/Tools | 10 | 30% | $1,674,020 | | 617,686 | | | 2,291,706 | 308,843 | 1,982,863 | 594,859 | 1,696,847 |
| 10 | Computer Software | 12 | 100% | $536,606 | | 5,512,315 | | | 6,048,921 | 2,756,158 | 3,292,764 | 3,292,764 | 2,756,158 |
| 11 | Leasehold Improvements | 13 | 1/6 | $153,908 | | 419,364 | | | 573,272 | 209,682 | 363,590 | 104,944 | 468,328 |
| 12 | Franchises | 14 | 1/5 | $300,000 | | - | | | 300,000 | - | 300,000 | 25,000 | 275,000 |
| 13 | Roads | 17 | 8% | $869,880 | | 950,000 | | | 1,819,880 | 950,000 | 869,880 | 145,590 | 1,674,290 |
| 14 | Heavy Work Improvement | 38 | 30% | $570,228 | | 50 | | | 570,278 | 25 | 570,253 | 171,076 | 399,202 |
| 15 | General EDP H/W | 45 | 45% | $71,094 | | - | | | 71,094 | - | 71,094 | 31,992 | 39,102 |
| 16 | Liquid Natural Gas Equipment | 47 | 8% | $76,499,643 | | 89,502,716 | | | 166,002,359 | 74,616,798 | 91,385,561 | 12,089,315 | 153,913,044 |
| 17 | Trns Pipe/Meas/Comm & Reg Eqp | 49 | 8% | $28,601,455 | | 7,884,145 | | | 36,485,600 | (456,727) | 36,942,327 | 2,939,117 | 33,546,483 |
| 18 | General EDP H/W post March 19, 2007 | 50 | 55% | $183,990 | | 1,166,263 | | | $1,350,253 | 583,132 | $767,121 | 421,917 | 928,336 |
| 19 | Natural Gas Distribution Lines | 51 | 6% | $47,577,569 | | 13,993,778 | | | $61,571,347 | $6,996,889 | $54,574,458 | 3,274,467 | 58,296,879 |
| 20 | Natural Gas Distribution Lines | 52 | 100% | $0 | | 311,628 | | | $311,628 | $0 | $311,628 | 311,628 | - |
| 21 | | | | $475,268,405 | $0 | $128,328,212 | $0 | $0 | $603,596,617 | $89,949,932 | $513,646,685 | $39,532,257 | $564,064,360 |

**Year Ended December 31, 2010 (trued-up to 2010 T2s)**

| Line | Description | Class | Rate | (1) Jan 1, 2010 UCC Opening | (2) Opening Adjustments | (3) Cost of Net Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) UCC Balance | (7) 1/2 of (3)-(4)+(5) | (8) UCC available for CCA | (9) CCA | (10) Dec 31, 2010 UCC Closing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $294,287,558 | | $1,360,100 | | | $295,647,658 | $0 | $295,647,658 | 11,825,906 | $283,821,751 |
| 2 | Building and Utility - post March 19, 2007 | 1.3 | 6% | 5,181,202 | | $339,152 | | | $5,520,354 | 169,576 | $5,350,778 | 321,047 | $5,199,307 |
| 3 | Utility Plant - pre 88 | 2 | 6% | 7,116,061 | | - | | | 7,116,061 | - | 7,116,061 | 426,964 | 6,689,097 |
| 4 | Building - post 87 | 3 | 5% | 142,748 | | - | | | 142,748 | - | 142,748 | 7,137 | 135,611 |
| 5 | Buildings Portable | 6 | 10% | 6,323 | | - | | | 6,323 | - | 6,323 | 632 | 5,691 |
| 6 | Trans Pipe Comp Equip | 7 | 15% | 18,180,207 | | 908,596 | | | 19,088,803 | 454,298 | 18,634,505 | 2,795,176 | 16,293,627 |
| 7 | F&F/Commun Equip - post 76 | 8 | 20% | 6,958,046 | | 576,100 | | | 7,534,146 | 288,050 | 7,246,096 | 1,449,219 | 6,084,927 |
| 8 | Commun Equip - pre 77 | 9 | 25% | 2 | | | | | 2 | - | 2 | 1 | 1 |
| 9 | Vehicles/Comp Equip/Tools | 10 | 30% | 1,796,293 | | 490,136 | | | 2,286,429 | 245,068 | 2,041,361 | 612,408 | 1,674,020 |
| 10 | Computer Software | 12 | 100% | 621,164 | | 1,073,212 | | | 1,694,376 | 536,606 | 1,157,770 | 1,157,770 | 536,606 |
| 11 | Leasehold Improvements | 13 | 1/6 | 108,165 | | 67,907 | | | 176,072 | 33,954 | 142,119 | 22,164 | 153,908 |
| 12 | Franchises | 14 | 1/5 | 325,000 | | - | | | 325,000 | - | 325,000 | 25,000 | 300,000 |
| 13 | Roads | 17 | 8% | - | | 941,000 | | | 941,000 | - | 941,000 | 71,120 | 869,880 |
| 14 | Heavy Work Improvement | 38 | 30% | 504,484 | | 255,399 | | | 759,883 | 127,700 | 632,183 | 189,655 | 570,228 |
| 15 | General EDP H/W | 45 | 45% | 129,263 | | - | | | 129,263 | - | 129,263 | 58,168 | 71,094 |
| 16 | Liquid Natural Gas Equipment | 47 | 8% | - | | 81,382,600 | | | 81,382,600 | - | 81,382,600 | 4,882,957 | 76,499,643 |
| 17 | Trns Pipe/Meas/Comm & Reg Eqp | 49 | 8% | 28,700,876 | | 2,323,093 | | | 31,023,969 | 323,547 | 30,700,422 | 2,422,514 | 28,601,455 |
| 18 | General EDP H/W post March 19, 2007 | 50 | 55% | 408,866 | | - | | | $408,866 | - | $408,866 | 224,876 | 183,990 |
| 19 | Natural Gas Distribution Lines | 51 | 6% | 38,415,087 | | 11,822,048 | | | $50,237,135 | 5,911,024 | $44,326,111 | 2,659,567 | 47,577,569 |
| 20 | Natural Gas Distribution Lines | 52 | 100% | - | | 210,997 | | | $210,997 | - | $210,997 | 210,997 | - |
| 21 | | | | $402,881,343 | $0 | $101,750,340 | $0 | $0 | $504,631,683 | $8,089,822 | $496,541,861 | $29,363,278 | $475,268,405 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**UCC CONTINUITY - INCOME TAX PURPOSES (Shareholder)**

## Year Ended December 31, 2011

| Line | Description | Class | Rate | (1) Jan 1, 2011 UCC Opening | (2) Opening Adjustments | (3) Cost of Net Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) UCC Balance | (7) 1/2 of (3)-(4)+(5) | (8) UCC available for CCA | (9) CCA | (10) Dec 31, 2011 UCC Closing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $283,821,751 | | $0 | | | $283,821,751 | $0 | $283,821,751 | $11,352,870 | $272,468,881 |
| 2 | Building and Utility - post 2007 | 1.3 | 6% | 5,199,307 | | 6,251,885 | | | 11,451,192 | 3,125,943 | 8,325,250 | 556,756 | 10,894,436 |
| 3 | Utility Plant - pre 88 | 2 | 6% | 6,689,097 | | - | | | 6,689,097 | - | 6,689,097 | 401,346 | 6,287,752 |
| 4 | Building - post 87 | 3 | 5% | 135,611 | | - | | | 135,611 | - | 135,611 | 6,781 | 128,830 |
| 5 | Buildings Portable | 6 | 10% | 5,691 | | - | | | 5,691 | - | 5,691 | 569 | 5,122 |
| 6 | Trans Pipe Comp Equip | 7 | 15% | 16,293,627 | | 864,064 | | | 17,157,691 | 432,032 | 16,725,659 | 2,508,849 | 14,648,842 |
| 7 | F&F/Commun Equip - post 76 | 8 | 20% | 6,084,927 | | 854,318 | | | 6,939,245 | 427,159 | 6,512,086 | 1,302,417 | 5,636,828 |
| 8 | Commun Equip - pre 77 | 9 | 25% | 1 | | - | | | 1 | - | 1 | 0 | 1 |
| 9 | Vehicles/Comp Equip/Tools | 10 | 30% | 1,674,020 | | 617,686 | | | 2,291,706 | 308,843 | 1,982,863 | 594,859 | 1,696,847 |
| 10 | Computer Software | 12 | 100% | 536,606 | | 5,512,315 | | | 6,048,921 | 2,756,158 | 3,292,764 | 3,292,764 | 2,756,158 |
| 11 | Leasehold Improvements | 13 | 1/6 | 153,908 | | 419,364 | | | 573,272 | 209,682 | 363,590 | 104,944 | 468,328 |
| 12 | Franchises | 14 | 1/5 | 300,000 | | - | | | 300,000 | - | 300,000 | 25,000 | 275,000 |
| 13 | Heavy Work Improvement | 17 | 1/5 | 869,880 | | 950,000 | | | 1,819,880 | 950,000 | 869,880 | 145,590 | 1,674,290 |
| 14 | Heavy Work Improvement | 38 | 30% | 570,228 | | 50 | | | 570,278 | 25 | 570,253 | 171,076 | 399,202 |
| 15 | General EDP H/W | 45 | 45% | 71,094 | | - | | | 71,094 | - | 71,094 | 31,992 | 39,102 |
| 16 | Trns Pipe/Meas/Comm & Reg Eqp | 47 | 8% | 76,499,643 | | 89,502,716 | | | 166,002,359 | 74,616,798 | 91,385,561 | 12,089,315 | 153,913,044 |
| 17 | Trns Pipe/Meas/Comm & Reg Eqp | 49 | 8% | 28,601,455 | | 7,884,145 | | | 36,485,600 | (456,727) | 36,942,327 | 2,939,117 | 33,546,483 |
| 18 | General EDP H/W post March 19, 2007 | 50 | 55% | 183,990 | | 1,166,263 | | | 1,350,253 | 583,132 | 767,121 | 421,917 | 928,336 |
| 19 | Natural Gas Distribution Lines | 51 | 6% | 47,577,569 | | 13,993,778 | | | 61,571,347 | 6,996,889 | 54,574,458 | 3,274,467 | 58,296,879 |
| 20 | Natural Gas Distribution Lines | 52 | 100% | - | | 311,628 | | | 311,628 | - | 311,628 | 311,628 | - |
| 21 | | | | $475,268,405 | $0 | $128,328,212 | $0 | $0 | $603,596,617 | $89,949,932 | $513,646,685 | $39,532,257 | $564,064,360 |

## Year Ended December 31, 2010 (trued-up to 2010 T2s)

| Line | Description | Class | Rate | (1) Jan 1, 2010 UCC Opening | (2) Opening Adjustments | (3) Cost of Net Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) UCC Balance | (7) 1/2 of (3)-(4)+(5) | (8) UCC available for CCA | (9) CCA | (10) Dec 31, 2010 UCC Closing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $294,287,558 | | $1,360,100 | | | $295,647,658 | $0 | $295,647,658 | $11,825,906 | $283,821,751 |
| 2 | Building and Utility - post 2007 | 1.3 | 6% | 5,181,202 | | 339,152 | | | 5,520,354 | 169,576 | 5,350,778 | 321,047 | 5,199,307 |
| 3 | Utility Plant - pre 88 | 2 | 6% | 7,116,061 | | - | | | 7,116,061 | - | 7,116,061 | 426,964 | 6,689,097 |
| 4 | Building - post 87 | 3 | 5% | 142,748 | | - | | | 142,748 | - | 142,748 | 7,137 | 135,611 |
| 5 | Buildings Portable | 6 | 10% | 6,323 | | - | | | 6,323 | - | 6,323 | 632 | 5,691 |
| 6 | Trans Pipe Comp Equip | 7 | 15% | 18,180,207 | | 908,596 | | | 19,088,803 | 454,298 | 18,634,505 | 2,795,176 | 16,293,627 |
| 7 | F&F/Commun Equip - post 76 | 8 | 20% | 6,958,046 | | 576,100 | | | 7,534,146 | 288,050 | 7,246,096 | 1,449,219 | 6,084,927 |
| 8 | Commun Equip - pre 77 | 9 | 25% | 2 | | - | | | 2 | - | 2 | 1 | 1 |
| 9 | Vehicles/Comp Equip/Tools | 10 | 30% | 1,796,293 | | 490,136 | | | 2,286,429 | 245,068 | 2,041,361 | 612,408 | 1,674,020 |
| 10 | Computer Software | 12 | 100% | 621,164 | | 1,073,212 | | | 1,694,376 | 536,606 | 1,157,770 | 1,157,770 | 536,606 |
| 11 | Leasehold Improvements | 13 | 1/6 | 108,165 | | 67,907 | | | 176,072 | 33,954 | 142,119 | 22,164 | 153,908 |
| 12 | Franchises | 14 | 1/5 | 325,000 | | - | | | 325,000 | - | 325,000 | 25,000 | 300,000 |
| 13 | Roads | 17 | 1/5 | - | | 941,000 | | | 941,000 | - | 941,000 | 71,120 | 869,880 |
| 14 | Heavy Work Improvement | 38 | 30% | 504,484 | | 255,399 | | | 759,883 | 127,700 | 632,183 | 189,655 | 570,228 |
| 15 | General EDP H/W | 45 | 45% | 129,263 | | - | | | 129,263 | - | 129,263 | 58,168 | 71,094 |
| 16 | Liquid Natural Gas Equipment | 47 | 8% | - | | 81,382,600 | | | 81,382,600 | - | 81,382,600 | 4,882,957 | 76,499,643 |
| 17 | Trns Pipe/Meas/Comm & Reg Eqp | 49 | 8% | 28,700,876 | | 2,323,093 | | | 31,023,969 | 323,547 | 30,700,422 | 2,422,514 | 28,601,455 |
| 18 | General EDP H/W post March 19, 2007 | 50 | 55% | 408,866 | | - | | | 408,866 | - | 408,866 | 224,876 | 183,990 |
| 19 | Natural Gas Distribution Lines | 51 | 6% | 38,415,087 | | 11,822,048 | | | 50,237,135 | 5,911,024 | 44,326,111 | 2,659,567 | 47,577,569 |
| 20 | Natural Gas Distribution Lines | 52 | 100% | - | | 210,997 | | | 210,997 | - | 210,997 | 210,997 | - |
| 21 | | | | $402,881,343 | $0 | $101,750,340 | $0 | $0 | $504,631,683 | $8,089,822 | $496,541,861 | $29,363,278 | $475,268,405 |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.** **10.1.3**
**ANNUAL REPORT - 2011**
**FUTURE INCOME TAXES (FIT)**

| Line No. | Particulars | As at Dec. 31/11 |
|---|---|---|
| 1 | Property, Plant & Equipment | |
| 2 | Net Book Value | ($812,568,556) |
| 3 | Less: Undepreciated Capital Cost * | (592,849,679) |
| 4 | | (219,718,877) |
| 5 | Weighted Average Future Tax Rate | 25% |
| 6 | | (54,929,719) |
| 7 | Total FIT Liability - After tax (PP&E) | (54,929,719) |
| 8 | Total FIT Liability - After tax (Non-PP&E) | 238,514 |
| 9 | Total FIT Liability - After tax | (54,691,205) |
| 10 | Tax Gross Up | (18,230,402) |
| 11 | FIT Liability/Asset - End of Year | (72,921,607) |
| 12 | FIT Liability/Asset - Opening Balance | (63,783,427) |
| 13 | FIT Liability/Asset - Mid Year | ($68,352,517) |

* Undepreciated Capital Cost of $564,064,361 per Schedule 10.1.1 plus tax value of land and WIP of $28,785,318

## FORTISBC ENERGY (VANCOUVER ISLAND) INC.
## ANNUAL REPORT - 2011
## UTILITY RATE BASE



| Line No. | Particulars | Reference | 2011 | 2010 |
|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | |
| 1 | Beginning of Year | 2.1.0 | $1,023,378,559 | $1,007,359,300 |
| 2 | End of Year | 2.1.0 | 1,252,735,744 | 1,023,378,559 |
| 3 | Average Balance - Mid-Year | | $1,138,057,152 | $1,015,368,929 |
| | ACCUMULATED DEPRECIATION - PLANT | | | |
| 4 | Beginning of Year | 3.1.0 | ($267,254,082) | ($244,628,217) |
| 5 | End of Year | 3.1.0 | (294,007,621) | (267,254,082) |
| 6 | Average Balance - Mid-Year | | ($280,630,851) | ($255,941,149) |
| | CIAC | | | |
| 7 | Beginning of Year | 2.5.0 | ($275,876,143) | ($278,712,005) |
| 8 | End of Year | 2.5.0 | (276,650,044) | (275,876,143) |
| 9 | Average Balance - Mid-Year | | ($276,263,094) | ($277,294,074) |
| | ACCUMULATED DEPRECIATION - CIAC | | | |
| 10 | Beginning of Year | 2.5.0 | $54,799,368 | $50,378,875 |
| 11 | End of Year | 2.5.0 | 59,227,262 | 54,799,368 |
| 12 | Average Balance - Mid-Year | | $57,013,315 | $52,589,122 |
| 13 | NET MID-YEAR PLANT IN SERVICE | | $638,176,522 | $534,722,828 |
| 14 | Work in Progress - No AFUDC | | 2,428,680 | 2,279,866 |
| 15 | 13-month average adjustment | | 15,536,398 | (1,131,419) |
| 16 | Working Capital Requirements[1] | 9.0.0 | 9,972,763 | 11,694,244 |
| 17 | Future Income Taxes Regulatory Asset | 10.1.3 | 68,352,517 | 60,306,325 |
| 18 | Future Income Taxes Liability | 10.1.3 | (68,352,517) | (60,306,325) |
| 19 | UTILITY RATE BASE, MID-YEAR [1] | | $666,114,363 | $547,565,519 |

[1] 2010 figures have been restated.

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**CAPITAL STRUCTURE AND COST OF CAPITAL**

**2011**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 1 | Short Term Debt | | $34,142,620 | 5.13% | 6.80% | 0.35% | 2,320,759 | 2,320,759 |
| 2 | Long Term Debt | | 365,525,998 | 54.87% | 5.63% | 3.09% | 20,568,752 | 20,568,752 |
| 3 | Common Equity | | 266,445,745 | 40.00% | 10.00% | 4.00% | 26,644,575 | |
| 4 | Mid Year Rate Base | 11.0.0 | $666,114,363 | 100.00% | | 7.44% | 49,534,086 | 22,889,511 |

Long Term Debt Continuity Schedule

| Line | Particulars | Balance Jan 1, 2011 | Additions | Repayments | Balance Dec 31, 2011 | Weighted Avg Balance | % of Total | Interest Expense | Annual Effective Rate | Weighted Average % |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | $350 million Bond | 350,000,000 | - | - | 350,000,000 | 350,000,000 | 95.75% | 20,374,537 | 5.82% | 5.57% |
| 6 | PCEPA Repayment Loan | 15,525,998 | - | - | 15,525,998 | 15,525,998 | 4.25% | 293,455 | 1.89% | 0.08% |
| 7 | Adjustment - BA Discount, Hedged Interest, etc. | - | - | - | - | - | 0.00% | 389,719 | n.a. | 0.00% |
| 8 | Capitalized Long Term Interest on CPCNs | | | | | | | (488,959) | | |
| 9 | Total | $365,525,998 | $0 | $0 | $365,525,998 | $365,525,998 | 100.00% | $20,568,752 | 5.63% | 5.63% |

**2010**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 10 | Short Term Debt[1] | | $55,752,361 | 10.18% | 2.10% | 0.21% | $1,169,968 | $1,169,968 |
| 11 | Long Term Debt[1] | | 272,786,950 | 49.82% | 5.64% | 2.81% | 15,376,229 | 15,376,229 |
| 12 | Common Equity[1] | | 219,026,208 | 40.00% | 10.00% | 4.00% | 21,902,621 | |
| 13 | Mid Year Rate Base[1] | 11.0.0 | $547,565,519 | 100.00% | | 7.02% | 38,448,818 | 16,546,197 |

Long Term Debt Continuity Schedule

| Line | Particulars | Balance Jan 1, 2009 | Additions | Repayments | Balance Dec 31, 2008 | Weighted Avg Balance | % of Total | Interest Expense | Annual Effective Rate | Weighted Average % |
|---|---|---|---|---|---|---|---|---|---|---|
| 14 | $350 million Bond | 250,000,000 | 100,000,000 | - | 350,000,000 | 258,333,333 | 94.70% | 15,533,126 | 6.01% | 5.69% |
| 15 | PCEPA Repayment Loan | 13,381,236 | 2,144,762 | - | 15,525,998 | 14,453,617 | 5.30% | 209,818 | 1.45% | 0.08% |
| 16 | Adjustment - BA Discount, Hedged Interest, etc. | - | - | - | - | - | 0.00% | 328,025 | n.a. | 0.00% |
| 17 | Capitalized Long Term Interest on CPCNs[1] | | | | | | | (694,740) | | |
| 18 | Total | $263,381,236 | $102,144,762 | $0 | $365,525,998 | $272,786,950 | 100.00% | $15,376,229 | 5.64% | 5.64% |

[1] 2010 figures have been restated.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
# ANNUAL REPORT - 2011
# EXECUTIVE COMPENSATION

With a single management and support team for the entire FortisBC Energy Inc. group of companies, services are delivered on a shared basis. Utilizing a framework similar to that used by FortisBC Holdings Inc. to allocate corporate center management fees to FortisBC Energy Inc., the allocated shared services cost to FortisBC Energy (Vancouver Island) Inc. from FortisBC Energy Inc. was $7.54 million in 2011.

# FORTISBC ENERGY (VANCOUVER ISLAND) INC.
# ANNUAL REPORT – 2011
# NEW DIRECTIONS TO THE UTILITIES UNDER BCUC'S JURISDICTION

## 1. Outlook 2012 Capital Projects

Projected capital expenditures may be found in the 2012/2013 Revenue Requirements Application Evidentiary Update filed with the Commission in September 2011. Below are the material capital projects and their current forecast expenditures in 2012 (identified projects exclude AFUDC).

FEVI considers material capital expenditures to be those projects with expenditures equal to or greater than 1% of rate base.

- Victoria Regional Operations Centre Project - $6.8 million in 2012

## 2. 2011 Material Capital Projects

Mt. Hayes LNG Storage Facility

FEVI filed an application with the Commission on June 5, 2007 seeking approval for the Mt. Hayes Storage Project, including construction and ownership of an LNG peak-shaving storage facility, at Mt. Hayes near Ladysmith, and various associated facilities to connect the LNG Storage Facility to FEVI's natural gas transmission system. The Application sought approval of a storage and delivery agreement between FEVI and FEI.

In November 2007, the Commission issued Order No. C-9-07 to grant conditional approval for the project and later confirmed in April 2008 that the conditions were met. The total approved project capital cost is at $193.3 million (excluding AFUDC) with completion in 2011.

FEVI has completed on-site construction and the facility was put in service in May 2011. The final project spend is $190.4 million (excluding AFUDC). For more detailed progress updates throughout 2011, please refer to the quarterly progress reports filed with the Commission.

Victoria Regional Operations Centre Project

FEVI filed an application with the Commission on October 13, 2010 seeking approval to acquire property and construct a new regional facility replacing its existing leased facility.

In January 2011, the Commission issued Order No. C-1-11 to grant conditional approval for the acquisition of the property and deferred approval for construction until completion and review of the staffing report. FEVI filed the required report on February 28, 2011. On March 23, 2011 the Commission issued Order No. C-

6-11 granting approval to construct the Victoria Regional Operations Centre. The total project capital cost is estimated at $13.2 million (excluding AFUDC). Purchase of the property was complete in April 2011 for approximately $5 million. Majority of the construction to take place in 2012. Completion of the project is expected in October 2012.

## 3. Income Tax Assessments

Income tax assessments and re-assessments received in 2011 are attached.

## 4. Management Letters

The Company's auditors issued a management letter for FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. Please see the FortisBC Energy Inc. annual report for details.

## 5. Internal Audit

There were no internal audits specifically addressing FortisBC Energy (Vancouver Island) Inc. matters only. Any reports that are relevant to FEVI are included in Tab 13 of the FEI Annual Report.

## 6. Reconciliation

The reconciliation of the Annual Report with the financial statements is on pages 1.6.0 and 1.7.1 of the Annual Report.

## 7. Regulatory Compliance

FEVI's accounting system conforms to the Uniform System of Accounting with the exception of Operations & Maintenance expenses which are reported according to both a resource view and an activity view as approved by order G-154-07. This is in accordance with the Commission's financial directions.

## 8. Refundable Contributions

Refundable contributions of $2,536 were received in 2011.
Customers were refunded prior contributions of $2,489 in 2011. No amount was transferred to Contribution In Aid Of Construction.

## 9. System Outages

Outages affecting customers on the FortisBC Energy (Vancouver Island) system during 2011 were as follows:

| | |
|---|---|
| System Total | |
| Outages: | 204 |
| Outages caused by Third Party: | 204 |
| Customers Affected: | 175 |
| Maximum Customers Affected by an Outage: | 27 |

## 10. Leaks per Kilometer of Transmission Pipeline

Under Provincial Spill Reporting guidelines, there were zero through-wall pipe leaks in 2011.

## 11. Leaks per Kilometer of Distribution Pipeline

This directional indicator measures below ground leaks on distribution mains and services only (excludes above ground leaks). For 2011, FEVI's leaks per kilometer of distribution pipeline were 0.009 (51 leaks on 5,672 km of distribution pipe).

## 12. Emergency Response Time

This indicator measures the duration between the time the incident is first reported to the time first responder is on-site. In 2011, FEVI's emergency response time was 18.9 minutes.

## 13. Reconciliation of Regulatory Accounts to Canadian GAAP

As requested by BCUC Order G-117-11, a reconciliation of amounts reported for regulatory accounting to those amounts that would be reported under 2011 Canadian GAAP is attached.

Canada Revenue Agency | Agence du revenu du Canada

Surrey BC V3T 5E1



| | |
|---|---|
| Date of mailing | August 22, 2011 |
| Business Number | 12174 3074 RC0001 |
| Tax year-end | December 31, 2010 |

FORTISBC ENERGY (VANCOUVER
ISLAND) INC.
10FL-1111 GEORGIA ST W
VANCOUVER BC V6E 4M3

0007134

# CORPORATION NOTICE OF ASSESSMENT

## RESULTS

**Thank you for choosing to use our Corporation Internet Filing service.**

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

| | | |
|---|---|---|
| Result of this Assessment : | $ | 1.00 Cr |
| Administrative adjustment: | $ | 1.00 |
| Prior balance: | $ | 0.00 |
| | | ================ |
| Total balance: | $ | 0.00 |

We do not charge or refund an amount of $2.00 or less.

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

FORTISBC ENERGY (VANCOUVER ISLAND) INC.



| | |
|---|---|
| Date of mailing | August 22, 2011 |
| Business Number | 12174 3074 RC0001 |
| Tax year-end | December 31, 2010 |

# CORPORATION NOTICE OF ASSESSMENT

## SUMMARY OF ASSESSMENT

| | $ Reported | $ Assessed |
|---|---|---|
| **Federal Tax:** | | |
| Part I | 6,873,883.00 | 6,873,883.00 |
| Part I.3 | 0.00 | 0.00 |
| Part II | 0.00 | 0.00 |
| Part III.1 | 0.00 | 0.00 |
| Part IV | 0.00 | 0.00 |
| Part IV.1 | 0.00 | 0.00 |
| Part VI | 0.00 | 0.00 |
| Part VI.1 | 0.00 | 0.00 |
| Part XIII.1 | 0.00 | 0.00 |
| Part XIV | 0.00 | 0.00 |
| **Total Federal Tax:** | | $ 6,873,883.00 |
| **Net Provincial and Territorial Tax/Credit:** | | |
| British Columbia | 4,009,766.00 | 4,009,766.00 |
| **Total Net Provincial and Territorial Tax/Credit:** | | $ 4,009,766.00 |
| Instalment(s) applied | | 10,883,650.00 Cr |
| Net balance: | | $ 1.00 Cr |
| Result of this assessment: | | $ 1.00 Cr |
| Administrative adjustment: | | $ 1.00 |
| Prior balance: | | $ 0.00 |
| Total balance: | | $ 0.00 |

Linda Lizotte-MacPherson
Commissioner of Revenue

## EXPLANATION

We have provided a breakdown of the provincial and territorial tax and credit amounts.

Net British Columbia tax/credit consists of the following:
British Columbia tax $ 4,009,766.00

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide" or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information online.

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

Canada Revenue Agency / Agence du revenu du Canada

FORTISBC ENERGY (VANCOUVER ISLAND) INC.



| | |
|---|---|
| Date of mailing | August 22, 2011 |
| Business Number | 12174 3074 RC0001 |
| Tax year-end | December 31, 2010 |

0007135

**CORPORATION NOTICE OF ASSESSMENT**

For information visit www.cra.gc.ca or contact:

Business Enquiries: 1-800-959-5525
Surrey Tax Centre
9755 King George Boulevard
Surrey BC V3T 5E1
Fax 604-585-5772

Vancouver Tax Services Office

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**Summary of Refundable Contributions - 2011**

| Date | Description | Actual Contribution | Refunds / Transfers | Balance |
|---|---|---|---|---|
| Mar-2001 | Origin Adult Communities Inc (Fairwinds) | 288,000.00 | - | 288,000.00 |
| Jun-2005 | 653476 BC LTD | 900.00 | - | 900.00 |
| Mar-2011 | Edward Brackett | 2,489.14 | (2,489.14) | - |
| Aug-2011 | Chris Starkey | 46.74 | - | 46.74 |
| **Total** | | $ 291,435.88 | $ (2,489.14) | $ 288,946.74 |

| | |
|---|---|
| **Total contributions in 2011** | **$ 2,535.88** |
| **Total refunds / transfers in 2011** | **$ (2,489.14)** |

**FORTISBC ENERGY (VANCOUVER ISLAND) INC.**
**ANNUAL REPORT - 2011**
**RECONCILIATION OF REGULATORY ACCOUNTS TO CANADIAN GAAP FINANCIAL STATEMENTS**

| BALANCE SHEET | Financial | Reclasses | Reg Differences | Timing Differences | Annual Report Page 1.6 | Annual Report Rate Base (exc. Mid-year) | Non Rate Base /Non Reg | Description |
|---|---|---|---|---|---|---|---|---|
| **ASSETS** | | | | | | | | |
| *Current Assets* | | | | | | | | |
| Cash & Cash Equivalents | $ 14,948 | | | | $ 14,948 | $ 2,233 | $ 12,715 | Cash working capital component broken out |
| Accounts Receivable | $ 35,434 | $ 3,268 [3,17] | $ (794) [5] | | $ 37,908 | $ (1,261) | $ 39,169 | Reserve for bad debt broken out |
| Due from Related Parties | $ - | | | | $ - | | $ - | Investments in subs not regulated |
| Gas Inventory | $ 12,521 | | | | $ 12,521 | $ 12,521 | $ - | |
| Prepaid Expenses | $ 814 | | | | $ 814 | | $ 814 | Not included in working capital calculation |
| Future Income Taxes | $ 2,806 | | $ 70,813 [9] | | $ 73,619 | | $ 73,619 | Not included in working capital calculation |
| Employee Benefit Plan | $ 2,199 | $ (2,199) [4] | | | $ - | | $ - | |
| Gas Plant in Service | $ 768,204 | $ 553,653 [1,2,15,19] | | $ (20,000) [9] | $ 1,301,857 | $ 1,301,857 | $ - | |
| Gas Plant under Construction | $ 15,241 | $ 6,881 [15,20] | | | $ 22,122 | $ 2,497 | $ 19,625 | Not included in rate base |
| Non-Rate Base Plant | $ 896 | $ 13 [1] | | | $ 909 | | $ 909 | Non-rate base land and Sooke assets |
| Regulated CIAC | $ - | $ (276,650) [19] | | $ - | $ (276,650) | $ (276,650) | $ - | |
| Unamortized Debt Discount and Expense | $ - | $ 3,356 [6] | | | $ 3,356 | | $ 3,356 | Long-term debt issue costs are non-regulated |
| Deferred Charges | $ 123,747 | $ 22 [20] | $ (120,229) [7,8,9,18] | | $ 3,540 | $ (531) | $ 4,071 | Goodwill, VIJV legal costs are non-rate base |
| **TOTAL ASSETS** | $ 976,810 | $ 288,344 | $ (50,210) | $ (20,000) | $ 1,194,944 | | | |
| **LIABILITIES** | | | | | | | | |
| *Current Liabilities* | | | | | | | | |
| Short term notes | $ 62,000 | $ 15,526 [16] | | | $ 77,526 | | $ 77,526 | Debt for financial purposes only |
| Accounts Payable and Accrued | $ 66,825 | $ 2,007 [17] | $ (48,378) [5,7,18] | | $ 20,454 | $ (251) | $ 20,203 | Employee withholdings included in rate base |
| Due to related parties | $ 1,224 | | | | $ 1,224 | | $ 1,224 | Investments in subs not regulated |
| Income and other taxes | $ 6,308 | | | | $ 6,308 | | $ 6,308 | Tax payable for financial purposes only |
| Security Deposits | $ 1,504 | | | | $ 1,504 | | $ 1,504 | Not included in working capital calculation |
| Current Portion of Long Term Debt | $ 35,526 | $ (15,526) [16] | | $ (20,000) [9] | $ - | | $ - | |
| Allowance for Doubtful Accounts | $ - | $ 1,261 [3] | | | $ 1,261 | | $ 1,261 | Not included in working capital calculation |
| | | | | | | | $ - | |
| Accumulated Revenue Surplus | $ 87,887 | | $ (22,464) [8] | $ (18) [21] | $ 65,405 | | $ 65,405 | Not part of rate base |
| Pension Liabilities | $ 6,286 | $ (2,199) [4] | | $ 18 [21] | $ 4,105 | $ (4,105) | $ - | |
| Customer Deposits | $ 289 | | | | $ 289 | $ (289) | $ - | |
| Accumulated Depreciation - Gas Plant | $ - | $ 294,008 [1] | | | $ 294,008 | $ (294,008) | $ - | |
| Accumulated Depreciation - Non-Rate Base Plant | $ - | $ 13 [1] | | | $ 13 | | $ 13 | Depreciation on non rate base plant above |
| Accumulated Depreciation - Regulated CIAC | $ - | $ (59,227) [1] | | | $ (59,227) | $ 59,227 | $ - | |
| Deferred Credits | $ 186 | | $ (76) [8] | | $ 110 | $ (110) | $ - | |
| Long Term Debt | $ 346,642 | $ 3,358 [6] | | | $ 350,000 | | $ 350,000 | Debt for financial purposes only |
| Future Income Taxes | $ 52,910 | | $ 20,708 [8] | | $ 73,618 | | $ 73,618 | To recognize non-regulated portion of FIT |
| **EQUITY** | | | | | | | | |
| Common Stock | $ 151,977 | | | | $ 151,977 | | $ 151,977 | |
| Contributed Surplus | $ 62,259 | | | | $ 62,259 | | $ 62,259 | |
| Contributions and Grants (Government Loan) | $ - | $ 49,123 [2] | | | $ 49,123 | $ (49,123) | $ - | |
| Retained Earnings, opening difference | $ - | | | | $ - | | $ - | |
| Retained Earnings, current year-regulated | $ 94,987 | $ - | $ 3,098 | $ - | $ 98,085 | | $ 98,085 | |
| Retained Earnings, current year-other | $ - | | $ (3,098) [10,11,12,13,14] | | $ (3,098) | | $ (3,098) | |
| **TOTAL LIABILITIES + EQUITY** | $ 976,810 | $ 288,344 | $ (50,210) | $ (20,000) | $ 1,194,944 | $ 752,007 | | |
| | | | | | $ 0 | 752,006 | amount per annual report | |
| | | | | | | $ 1 | rounding/unexplained | |

**TGVI**
**INCOME STATEMENT**

| | Financial | Reclasses | Reg Differences | Timing Differences | Annual Report Page 12.0 | |
|---|---|---|---|---|---|---|
| **REVENUE** | | | | | | |
| Natural Gas Distribution | $ 201,838 | $ 1,697 [22] | $ (3,714) [10] | | $ 199,821 | |
| Transportation | $ 24,039 | | | | $ 24,039 | |
| Royalty Income | $ 15,303 | | | | $ 15,303 | |
| **TOTAL REVENUE** | $ 241,180 | $ 1,697 | $ (3,714) | $ - | $ 239,163 | |
| **EXPENSES** | | | | | | |
| Cost of natural gas | $ 85,310 | | | | $ 85,310 | |
| Operation and Maintenance | $ 27,299 | | | | $ 27,299 | |
| Depreciation & Amortization | $ 24,041 | | | | $ 24,041 | |
| Property and other taxes | $ 9,629 | | | | $ 9,629 | |
| Wheeling | $ 3,455 | | | | $ 3,455 | |
| **TOTAL EXPENSES** | $ 149,734 | $ - | $ - | $ - | $ 149,734 | |
| **OPERATING INCOME (LOSS)** | $ 91,446 | $ 1,697 | $ (3,714) | $ - | $ 89,429 | |
| Financing costs | $ 21,254 | $ 1,697 [22] | $ (61) [11] | | $ 22,890 | Earned Return on Short-term + Long-term debt |
| Interest on Sub-ordinated Debt | $ - | | | | $ - | |
| **EARNINGS (LOSS) BEFORE INCOME TAXES** | $ 70,192 | $ - | $ (3,653) | $ - | $ 66,539 | |
| Income tax expense (recovery) | $ 11,824 | | | | $ 11,824 | |
| **EARNINGS (LOSS) BEFORE REVENUE SURPLUS** | $ 58,368 | $ - | $ (3,653) | $ - | $ 54,715 | |
| Revenue Surplus | $ 28,625 | | | | $ 28,625 | |
| Higher Rate Base for financial than regulatory | $ - | | $ 132 [12] | | $ 132 | |
| Special Direction Provision | $ - | | $ (1,867) [13] | | $ (1,867) | |
| O&M expense adjustment from actual to allowed | $ - | | $ 1,180 [14] | | $ 1,180 | |
| **NET INCOME (LOSS)** | $ 29,743 | $ - | $ (3,098) | $ - | $ 26,645 | Earned Return on Equity |
| **RETAINED EARNINGS** | | | | | | |
| Balance Beginning of Year | $ 87,244 | | | | $ 79,301 | |
| Add: Net Income | $ 29,743 | $ - | $ (3,098) | $ - | $ 26,645 | |
| Less: Dividends | $ (22,000) | | | | $ (20,500) | |
| Balance End of Year | $ 94,987 | | | | $ 85,446 | |

**FEVI Entries**

[1] Reclass accumulated depreciation classified as liability for reg purposes and asset for financial purposes
[2] Reclass Contributions and Grants classified as equity for reg purposes and asset for financial purposes
[3] Reclass allowance for doubtful account classified as liability for reg purposes and asset for financial purposes
[4] Reclass employee benefit plan classified as liability for reg purposes and asset for financial purposes.
[5] Reclass Royalty Revenue receivable classified as liability for reg purposes and asset for financial purposes.
[6] Reclass unamortized long-term debt issue costs classified as assets for reg purposes and liabilities for financial purposes
[7] Ineffective hedges relating to cost of gas for financial purposes only
[8] Non-regulated FIT for financial purposes only (FIT included on Reg schedules beginning 2011).
[9] Government loan reclass-timing. Booked in Reg books in 2011, financial books in 2010.
[10] To recognize AFUDC-Equity is non-regulated
[11] To recognize Interest on Goodwill is non-regulated
[12] To recognize that rate base for financial purposes is higher than rate base for Reg purposes
[13] Special Direction provision dis-allowed for Reg purposes
[14] To adjust O&M from actual to allowed for Reg purposes
[15] Reclass CCE project additions as WIP for reg purposes and asset for financial purposes
[16] Reclass PCEPA loan from current portion as short term debt for reg purposes and long term debt for financial purposes
[17] Reclass as accounts payable for reg purposes and accounts receivable for financial purposes
[18] Deferral provisions for financial purposes only (non-regulated)
[19] To separate out Regulated CIAC embedded in Property, Plant & Equipment
[20] Reclass as deferral for for reg purposes and WIP for financial purposes.
[21] Pension adjustment-timing. Booked in Reg books 2011, financial books 2012.
[22] Reclass RSDA interest classified as interest expense for reg purposes and revenue for financial purposes.

**8. Historical (2002-2011) regulatory financial information by year:**

a. Capital Structure Components: common equity, preferred equity, long and short-term debt:

   i. Rate Base: opening, closing and mid-year,

   ii. Gross rate base if different from rate base that is subject to debt and equity return,

   iii. Income statement,

   iv. Summary and full detailed description of all deferral and reserve accounts:

b. Summary and full detailed description of all deferral and reserve accounts:

   i. Average percentage of delivery revenue covered by each account,

   ii. Average percentage of total revenue (including commodity/energy cost) covered by each amount

- See attached **electronic** documents for FEVI’s financial information

**9. Price to Book Value Ratios (including supporting calculations) since 2000 when the utility or its corporate parent has been acquired by another firm:**

- See section 9 of FEI's Minimum Filing Requirements

a. Interpretation of Price to Book Values Ratios

- The FBCU interprets the above Price to Book Value ratios as representative of transactions that occurred at a point in time and that there are factors other than the Price to Book Value ratios that are more relevant in determining a fair return.

- For discussion on the general relevance of Price to Book Value with respect to the Generic Cost of Capital proceeding, please see the Price to Book Value section in the expert testimony of Aaron Engen as part of FBCU's Other Filing Requirements submission.

**10. Full explanation of any significant changes in accounting policy in the last 10 years.**

- See the attachment for discussion on FEVI's accounting policy changes in the last 10 years.

## FortisBC Energy (Vancouver Island Inc.
## 10 Year Summary of Significant Changes in Accounting Policy included in Regulatory Applications (2002-2011)

**2002 Revenue Requirements Application**

Centra Gas' revenue requirement period was from 2000 to 2002; therefore no changes in accounting policies were implemented in 2002 for regulatory purposes.

**2003 - 2005 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2003 Annual Review of 2004 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2004 Annual Review of 2005 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2006 - 2007 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2006 Annual Review of 2007 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2007 Application for the Approval of a Two-Year Extension of the 2006-2007 Revenue Requirement Settlement Agreement for 2008-2009**

The 2006-2007 Revenue Requirement Settlement Agreement was extended for two more years with no material changes.

**2007 Annual Review of 2008 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2008 Annual Review of 2009 Revenue Requirements Application**

This application included one accounting policy change:

| | | |
|---|---|---|
| Section 6.8 | Financial Accounting Matters – Inventories | Pages 43 |

Section 3031, Inventories, requires inventories to be measured at the lower of cost or net realizable value, disallows the use of a last-in first-out inventory costing methodology, and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the writedown is to be reversed. This standard is to be applied retrospectively. As at January 1, 2008, supplies and other inventories of approximately $1 million were reclassified to property, plant and equipment from inventory on the balance sheet as they are held for the development, construction, maintenance and repair of other property, plant and equipment. A reclassification from inventory to PP&E WIP has no effect on the utility's Rate Base since both Inventory and WIP (not attracting AFUDC) are calculated based on a 13 month average balance.

**2010-2011 Revenue Requirements Application**

This Application included the following accounting policy changes:

| | | |
|---|---|---|
| Section 11 | Accounting and Other Policies – Section a | Page 362 |

Currently, TGVI uses the taxes payable (flow-through) method to calculate income tax for regulatory purposes. In accordance with Canadian GAAP, a future income tax liability and offsetting regulatory future income tax asset is also recognized.

Depending on the outcome of the proposed IASB exposure draft on Rate-regulated Activities, to the extent this resulting asset meets the recognition criteria under the new standard, the current treatment would continue.

For purposes of this RRA, TGVI has assumed that the current treatment would be acceptable under IFRS, and proposes to record in rate base both the Future Income Tax Liability compliant with both Canadian GAAP and IFRS, and an offsetting Regulated Future Income Tax asset according to Canadian GAAP. Once the exposure draft for Rate-regulated Accounting is released, TGVI will consider whether an application to the BCUC is appropriate to reflect a revised approach.

| | | |
|---|---|---|
| Section 11 | Accounting and Other Policies – Sections a and b | Pages 354 - 363 |

As a result of the Negotiated Settlement Agreement (NSA), the Company adopted the following new accounting policies on a prospective basis.

i. Training and Feasibility Study Costs to be treated as O&M expense, rather than capital.
ii. Capitalization of Major Inspection and Overhaul Costs, including the creation of new Asset Classes.
iii. Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects.
iv. Capitalization of Depreciation on Assets used in Construction.
v. All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time.
vi. Adoption of the effective interest method for calculating interest expense on long-term debt.
vii. Asset removal costs are recorded in operating and maintenance expense on the statement of earnings and comprehensive earnings. The annual amount of such costs approved for recovery in customer rates in 2010 is $343 thousand. Actual costs incurred in excess of or below the approved amount are to be recorded in a regulatory deferral account for recovery from, or

refund to, customers in future rates starting in 2012. For the year ended December 31, 2010, the Company incurred $782 thousand of actual removal costs, with $439 thousand being recorded in the deferral account. Prior to January 1, 2010, actual asset removal costs were recorded against accumulated amortization on the consolidated balance sheet.

viii. Gains and losses on the sale or removal of utility capital assets are recorded in a regulatory deferral account on the balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval. For the year ended December 31, 2010, $660 thousand of losses were deferred and recorded in the related long-term regulatory asset on the balance sheet. Prior to January 1, 2010, gains and losses on the sale or disposal of utility capital assets were recorded against accumulated amortization.

# Appendix C

# COMPANY SPECIFIC INFORMATION FOR FEW

## FortisBC Energy (Whistler) Inc. ("FEW")

FEW is a company incorporated under the laws of the Province of British Columbia, operating since 1980. Until 2009, FEW was serviced by a piped propane distribution system. Today, FEW is engaged in sales and transportation services of natural gas to residential and commercial customers in Whistler, currently serving approximately 2,600 customers throughout the Province. FEW's service is provided through approximately 139 kilometres of pipeline. FEW's distribution network serves more than 0.25 percent of natural gas customers in BC and delivers more than 0.05 percent of the total energy consumed in the Province. Table below summarizes FEW's company profile.

| | |
|---|---|
| **Type of Utility** | Local Distribution Company |
| **Energy Product Offering** | Natural gas |
| **Service Area** | Whistler |
| **Rate Base*** | $41.5 (millions) |
| **Sales/Transportation Volumes*** | 716 TJs |
| **Number of Customers*** | 2,629 |
| **Customer Additions*** | 19 |
| **Customer Growth Rate*** | 1% |
| **Customer Profile by Demand*** | |
| Residential | 33% |
| Commercial | 67% |
| **Customer Profile by Margin*** | |
| Residential | 35% |
| Commercial | 65% |

*Based on 2012 Forecast, 2012-2013 RRA

## 1. Most recent Annual Report

- Annual Financial Statements for the Year-ended December 31, 2011

**Filed Confidentially**

**2. Credit Rating Agency reports for the utility and corporate parent since 2006:**

- There are no Credit Rating Agency reports for FEW as it has no third party long-term debt
- Its direct parent, Fortis Holdings Inc. and its ultimate parent, Fortis Inc. (FTS).can be found in section 2 of FEI's Company Related Document filings

a. Debt Rating
- Ratings are included in the reports - See reports for FHI and FTS in section 2 of FEI's Company Related Document filings

b. Schedule showing the history of any debt rating changes since 2002
- For FHI and FTS, see schedule – "Changes in ratings since 2002" in section 2 of FEI's Company Related Document filings

c. Interest coverage ratio and other agency's key debt ratios since 2006
- Rating Agency reports include key ratios – See reports for FHI and FTS in section 2 of FEI's Company Related Document filings

**3. Reports by investment analysts for the utility and corporate parent since 2006, where applicable:**

- There are no equity investment analyst reports for FEW or its direct parent, FHI Inc.
- See section 3 of FEI's Company Related Documents for equity investment analyst reports for FEW's ultimate parent, Fortis Inc. (FTS)
- There are no debt investment analyst reports for FEW
- See section 3 of FEI's Company Related Documents filing for debt investment analyst reports for FEW's ultimate parent, Fortis Inc. (FTS)

4. **All Prospectuses of Debt Offerings of the utility and/or its corporate parent within the last five years, if applicable:**

   - FEW did not have any debt issues during this time
   - FEW's direct parent, FortisBC Holdings Inc. (FHI) did not have any debt issues during this time
   - For Prospectuses of Debt Offerings by FEW's ultimate parent, Fortis Inc., see section 4 of FEI's Company Related Documents

   a. **Monthly (month end) spread data (market yield minus the yield on Government of Canada bond with similar time to maturity remaining) from 2006 to present date for a representative long-term bond issued by the utility**

      - Not Applicable

      i. **The time to maturity of both the utility bond and the government bond**

         - Not Applicable

      ii. **The trading liquidity of both bonds,**

         - Not Applicable

      iii. **The ratings on the bond for each quarter**

         - Not Applicable

      iv. **For the latest placement of bond, the spread over the corresponding Government bond yields, the current spread and the maturity date**

         - Not Applicable

**5. Full listing of each bond issue applicable for the 2012 Test Year including any future anticipated issues with full details (e.g. principal face value, nominal interest rate, effective rate if issued at discount or premium, relevant benchmark Government of Canada bond, credit spread benchmark, date of issue, date of maturity, length of maturity, etc.**

- Not Applicable as FEW does not have a bond issue

6. **All Prospectuses of Equity Offerings of the utility and/or its corporate parent within the last six years, if applicable:**

    - FEW is a wholly-owned private entity and only issues equity to its parent, FortisBC Holdings Inc.
    - FEW is indirectly and wholly-owned by its ultimate parent, Fortis Inc. (FTS – a TSX listed company).
    - See section 6 of FEI's Company Related Documents for FTS equity offerings

    a. **Details of any new equity issues from the financial market for the utility and/or corporate parent, if applicable:**

**7. Latest annual filing to the Commission of Operational and Financial Results.**

- See attached documents for FEW's latest annual filing

FORTIS BC™

**Diane Roy**
Director, Regulatory Affairs - Gas
**FortisBC Energy Inc.**

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

April 30, 2012

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

**Re: FortisBC Energy (Whistler) Inc.**
**2011 Annual Report of FortisBC Energy (Whistler) Inc.**

---

Please find attached, for the British Columbia Utilities Commission (the "Commission") review, three (3) copies of the FortisBC Energy (Whistler) Inc. (the "Company") 2011 Annual Report of Actual results.

We trust that the Commission will find this filing in order. If there are any questions regarding this filing, please contact the undersigned.

Yours very truly,

**FORTISBC ENERGY (WHISTLER) INC.**

***Original signed:***

Diane Roy

Attachment

GAS COMPANIES

ANNUAL REPORT

OF

FortisBC Energy (Whistler) Inc.

(Exact Legal Name of Utility)

16705 Fraser Highway, Surrey, B.C.  V4N 0E8

(Address of Principal Business Office)

TO THE

BRITISH COLUMBIA

UTILITIES COMMISSION

For the Period January 1, 2011 To December 31, 2011

**FORTISBC ENERGY (WHISTLER) INC.**

**ANNUAL REPORT FISCAL YEAR 2011**

## TABLE OF CONTENTS


**Page No.**

**Tab 1** Declaration ........................................ 1.0.0
Directors and Officers ........................................ 1.1.0
Control Over Utility and Corporations Controlled by Utility ........................................ 1.2.0
Important Changes During the Year ........................................ 1.3.0
Comparative Balance Sheet – Assets ........................................ 1.4.0
Comparative Balance Sheet – Liabilities ........................................ 1.5.0
Reconciliation of Annual Report to Financial Statements ........................................ 1.6.0
Statement of Net Income and Retained Earnings ........................................ 1.7.0
Reconciliation of Financial Statement Net Income to
Allowed Earned Return on Equity ........................................ 1.7.1
Deferred Regulatory Commission Expenses ........................................ 1.8.0
Lease/Rental Payments Charged to Operating Expenses ........................................ 1.9.0

**Tab 2** Gas Plant in Service Summary ........................................ 2.0.0
Gas Plant in Service ........................................ 2.1.0
Gas Plant Variance Explanation ........................................ 2.2.0
Gas Plant Under Construction & Held for Future Use ........................................ 2.3.0
Construction Overheads ........................................ 2.4.0
Contributions in Aid of Construction ........................................ 2.5.0

**Tab 3** Accumulated Provision for Depreciation Summary ........................................ 3.0.0
Accumulated Provision for Depreciation ........................................ 3.1.0

**Tab 4** Gas Account ........................................ 4.0.0
Gas Operating Revenues ........................................ 4.1.0
Other Revenue ........................................ 4.2.0
Temperature Normalization Adjustment ........................................ 4.3.0

**Tab 5** Gas Operating Expenses Summary ........ 5.0.0
Gas Operating Expenses ........ 5.1.0

**Tab 6** Pipeline Metres ........ 6.0.0

**Tab 7** Service Interruptions and Property Damage ........ 7.0.0

**Tab 8** System Map ........ 8.0.0

**Tab 9** Working Capital Requirements ........ 9.0.0
Cash Working Capital Requirements ........ 9.1.0
Working Capital – 13 Month Average ........ 9.2.0

**Tab 10** Earned Return ........ 10.0.0
Income Taxes ........ 10.1.0
UCC Continuities for Regulatory ........ 10.1.1
UCC Continuities for Income Tax ........ 10.1.2
Future Income Taxes ........ 10.1.3

**Tab 11** Utility Rate Base ........ 11.0.0

**Tab 12** Cost of Capital ........ 12.0.0

**Tab 13** Executive Compensation ........ 13.0.0

**Tab 14** New Directions to the Utilities Under BCUC's Jurisdiction
And Other Related Information ........ 14.0.0

**Tab 15** Unaudited Financial Statements ........ 15.0.0

# FORTISBC ENERGY (WHISTLER) INC.

## DECLARATION

## AS AT APRIL 30, 2012

**I, Roger Dall'Antonia, of Surrey, British Columbia, do hereby certify:**

1. That I am Vice President, Strategic Planning, Corporate Development & Regulatory Affairs of FortisBC Energy (Whistler) Inc. with its Operations Centre at 16705 Fraser Highway, Surrey, British Columbia, V4N 0E8.

2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 of the Utilities Commission Act.

3. That I confirm the Utility's compliance with the Commission's financial directions contained in Decisions and Orders.

***Original signed:***

Roger Dall'Antonia,
Vice President, Strategic Planning, Corporate Development & Regulatory Affairs

Name, title and address of office or other person to whom any questions concerning this report should be addressed:

Diane Roy,
Director, Regulatory Affairs (Gas)

FortisBC Energy (Whistler) Inc.
16705 Fraser Highway
Surrey, B.C.
V4N 0E8

# FORTISBC ENERGY (WHISTLER) INC.

## DIRECTORS AND OFFICERS

## AS AT DECEMBER 31, 2011

### OFFICERS

| Name | Business Address | Office Held |
|---|---|---|
| John C. Walker | 10th FLR - 1111 W Georgia St., Vancouver | President & CEO |
| Scott A. Thomson | 10th FLR - 1111 W Georgia St., Vancouver | Executive Vice President, Finance, Regulatory & Energy Supply |
| Douglas L. Stout | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Energy Solutions & External Relations |
| Dwain Bell | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Operations |
| Michael A. Mulcahy | 10th FLR - 1111 W Georgia St., Vancouver | Executive Vice President, Human Resources, Customer & Corporate Services |
| David C. Bennett | 10th FLR - 1111 W Georgia St., Vancouver | Vice President & General Counsel |
| Cynthia Des Brisay | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Energy Supply & Resource Development |
| Roger Dall'Antonia | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Finance & CFO; Treasurer |
| Robert M. Samels | 10th FLR - 1111 W Georgia St., Vancouver | Vice President, Business Planning |
| Thomas A. Loski | 10th FLR - 1111 W Georgia St., Vancouver | Vice-President, Customer Service |
| Debra G. Nelson | 10th FLR - 1111 W Georgia St., Vancouver | Corporate Secretary |
| Doyle Sam | 10th FLR - 1111 W Georgia St., Vancouver | Vice-President, Engineering & Generation |

### DIRECTORS

| Name | Business Address | Office Held |
|---|---|---|
| John C. Walker | 10th FLR - 1111 W Georgia St., Vancouver | Director and Chair |
| Michael A. Mulcahy | 10th FLR - 1111 W Georgia St., Vancouver | Director |
| Scott A. Thomson | 10th FLR - 1111 W Georgia St., Vancouver | Director |
| Douglas L. Stout | 10th FLR - 1111 W Georgia St., Vancouver | Director |

**FORTISBC ENERGY (WHISTLER) INC.**

**ANNUAL REPORT – 2011**

## CONTROL OVER UTILITY AND CORPORATIONS CONTROLLED BY UTILITY

FORTIS INC.

100%

FORTISBC HOLDINGS INC.

100%

FORTISBC ENERGY (WHISTLER) INC.

# FORTISBC ENERGY (WHISTLER) INC.

## IMPORTANT CHANGES DURING THE YEAR

- Customers served increased from 2,592 in 2010 to 2,649 in 2011, a 2.2% increase.
- Gas consumed by sales customers decreased from 753,195 GJ in 2010 to 736,844 GJ in 2011, a 2.17% decrease.
- Gas sales revenues decreased from $13,586,846 in 2010 to $12,175,955 in 2011, a 10.38% decrease.
- Approximately 2.932 kilometers of mains were installed in 2011 bringing the total pipe (mains) installed to approximately 98 kilometers at year-end.

**FORTISBC ENERGY (WHISTLER) INC.** **1.4.0**
**ANNUAL REPORT - 2011**
**COMPARATIVE BALANCE SHEET - Assets**

| Line No. | Particulars | Account No. | As At Dec. 31/11 ($000) | As At Dec. 31/10 ($000) | Increase (Decrease) ($000) |
|---|---|---|---|---|---|
| | Gross Plant | | | | |
| 1 | Gas Plant in Service | 100 | $ 16,823 | $ 16,408 | $ 415 |
| 2 | Gas Plant Leased to Others | 101 | | | - |
| 3 | Gas Plant Held for Future Use | 102 | | | - |
| 4 | Retirement Work in Progress | 103 | | | - |
| 5 | Other Plant | 110 | | | - |
| 6 | Gas Plant Under Construction | 115 | 221 | 107 | 114 |
| 7 | Other Plant Under Construction | 116 | | | - |
| 8 | Utility Plant Acquisition Adjustment | 117 | | | - |
| 9 | Total Plant | | $ 17,044 | $ 16,515 | $ 529 |
| | Long Term Investments | | | | |
| 10 | Investments in Affiliated Companies | 120 | | | $ - |
| 11 | Other Long Term Investments | 121 | | | - |
| 12 | Sinking Funds | 122 | | | - |
| 13 | Miscellaneous Special Funds | 123 | | | - |
| 14 | Company Long Term Debt Owned | 124 | | | - |
| 15 | Second Mortgage Receivable | 125 | | | - |
| 16 | Total Long Term Investments | | $ - | $ - | $ - |
| | Current and Accrued Assets | | | | |
| 17 | Cash | 130 | | | $ - |
| 18 | Special Deposits | 131 | | | - |
| 19 | Temporary Cash Investments | 132 | | | - |
| 20 | Accounts Receivable - Trade | 140 | 2,170 | 3,617 | (1,447) |
| 21 | Accounts Receivable - Other* | 141 | 1,745 | 46 | 1,699 |
| 22 | Accounts Receivable - Affiliated Co's | 142 | 657 | 560 | 97 |
| 23 | Interest and Dividends Receivable | 147 | | | - |
| 24 | Materials and Supplies - Gas | 150 | | | - |
| 25 | Materials and Supplies - Other | 151 | | | - |
| 26 | Gas Stored Underground | 152 | 654 | 958 | (304) |
| 27 | Transmission Line Pack | 153 | - | - | - |
| 28 | Prepayments | 160 | 14 | 20 | (6) |
| 29 | Other Current and Accrued Accounts | 162 | - | - | - |
| 30 | Total Current and Accrued Assets* | | $ 5,240 | $ 5,201 | $ 39 |
| | Deferred Charges | | | | |
| 31 | Future Income Taxes | | $ 2,286 | $ 1,932 | $ 354 |
| 32 | Unamortized Debt Discount and Expense | 170 | | | - |
| 33 | Extraordinary Plant Losses | 171 | | | - |
| 34 | Preliminary Surveys | 172 | 1,699 | 1,793 | (94) |
| 35 | Other Work in Progress | 173 | | | - |
| 36 | Unamortized Conversion Expenses | 175 | 7,885 | 8,307 | (422) |
| 37 | Public Improvements | 176 | | | - |
| 38 | Capital Stock Expense | 177 | | | - |
| 39 | Organization Expense | 178 | | | - |
| 40 | Other Deferred Charges | 179 | 22,173 | 22,310 | (137) |
| 41 | Total Deferred Charges | | $ 34,043 | $ 34,342 | $ (299) |
| 42 | Total Assets* | | $ 56,327 | $ 56,058 | $ 269 |

* 2010 comparatives have been restated.

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**COMPARATIVE BALANCE SHEET - Liabilities**

| Line No. | Particulars | Account No. | As At Dec. 31/11 ($000) | As At Dec. 31/10 ($000) | Increase (Decrease) ($000) |
|---|---|---|---|---|---|
| | Capital Stock and Surplus | | | | |
| 1 | Preferred Stock | 200 | | | |
| 2 | Common Stock | 205 | $ 16,671 | $ 16,671 | $ - |
| 3 | Contributed Surplus | 210 | | | - |
| 4 | Contributions and Grants | 211 | | | - |
| 5 | Retained Earnings* | 212 | 3,507 | 4,799 | (1,292) |
| 6 | Appropriated Retained Earnings* | 215 | | | - |
| 7 | Excess of RE-determined Value of | | | | - |
| 8 | Plant over Depreciated Cost | 216 | | | - |
| 9 | Total Capital Stock & Surplus* | | $ 20,178 | $ 21,470 | $ (1,292) |
| | Long Term Debt | | | | |
| 10 | Long Term Debt | 220 | | | $ - |
| 11 | Advances from Affiliated Companies | 248 | | | - |
| 12 | Other Long Term Debt | 249 | | | - |
| 13 | Total Long Term Debt | | $ - | $ - | $ - |
| | Current and Accrued Liabilities | | | | |
| 14 | Loans and Notes Payable | 250 | $ - | $ - | $ - |
| 15 | Accounts Payable and Accrued | 251 | 89 | 113 | (24) |
| 16 | Accounts Payable - Affiliated Companies | 252 | 28,740 | 26,757 | 1,983 |
| 17 | Dividends Payable | 253 | | | - |
| 18 | Customers' Security Deposits | 254 | 100 | 110 | (10) |
| 19 | Customers' Advances for Construction | 255 | 12 | 13 | (1) |
| 20 | Taxes Accrued* | 256 | 326 | 838 | (512) |
| 21 | Interest Payable and Accrued | 257 | 1 | - | 1 |
| 22 | Long Term Debt Due Within One Year | 258 | | | - |
| 23 | Other Current and Accrued Liabilities | 259 | | | - |
| 24 | Total Current and Accrued Liabilities | | $ 29,268 | $ 27,831 | $ 1,437 |
| | Deferred Credits | | | | |
| 25 | Unamortized Debt Premium | 270 | | | $ - |
| 26 | Unearned Charges on Custs.' Acct. Rec.(Cr) | 271 | | | - |
| 27 | Gas Cost and Maintenance Equalization | 275 | | | - |
| 28 | Future Income Taxes | 276 | 2,286 | 1,932 | 354 |
| 29 | Other Deferred Credits | 279 | 1,160 | 1,653 | (493) |
| 30 | Total Deferred Credits | | $ 3,446 | $ 3,585 | $ (139) |
| | Reserves | | | | |
| 31 | Accumulated Depreciation - Gas Plant | 105 | $ 3,420 | $ 3,156 | $ 264 |
| 32 | Accumulated Amortization - Gas Plant | 106 | | | - |
| 33 | Accumulated Depreciation - Other Plant | 111 | | | - |
| 34 | Accumulated Amortization - Other Plant | 112 | | | - |
| 35 | Allowance for Loss in Value of Investments | 126 | | | - |
| 36 | Allowance for Doubtful Accounts | 145 | 15 | 16 | (1) |
| 37 | Insurance Reserves | 290 | | | - |
| 38 | Welfare and Pension Reserves | 291 | | | - |
| 39 | Injuries and Damages Reserves | 292 | | | - |
| 40 | Other Reserves | 293 | | | - |
| 41 | Total Reserves | | $ 3,435 | $ 3,172 | $ 263 |
| 42 | Total Liabilities and Other Credits* | | $ 56,327 | $ 56,058 | $ 269 |

* 2010 comparatives have been restated.

**FORTISBC ENERGY (WHISTLER) INC.** **1.6.0**
**ANNUAL REPORT - 2011**
**RECONCILIATION OF ANNUAL REPORT TO FINANCIAL STATEMENTS**

| Line No. | Particulars | | As At Dec. 31/11 ($000) | | As At Dec. 31/10 ($000) | | Increase (Decrease) ($000) |
|---|---|---|---|---|---|---|---|
| 1 | Total Assets per page 1.4.0 of the Annual Report* | $ | 56,327 | $ | 56,058 | $ | 269 |
| 2 | Accumulated Depreciation | | (3,420) | | (3,156) | | (264) |
| 3 | Allowance for Doubtful Accounts | | (15) | | (16) | | 1 |
| 4 | Deferred Charges and Credits adjustments* | | 447 | | 544 | | (97) |
| 5 | FIT embedded in deferrals | | 827 | | 741 | | 86 |
| 6 | Allocated Gas in Storage | | - | | - | | - |
| 7 | Total Assets per Financial Statements* | $ | 54,166 | $ | 54,171 | $ | (5) |
| 8 | Total Liabilities per page 1.5.0 of the Annual Report* | $ | 56,327 | $ | 56,058 | $ | 269 |
| 9 | Accumulated Depreciation | | (3,420) | | (3,156) | | (264) |
| 10 | Allowance for Doubtful Accounts | | (15) | | (16) | | 1 |
| 11 | Deferred Charges and Credits adjustments* | | 447 | | 544 | | (97) |
| 12 | FIT embedded in deferrals | | 827 | | 741 | | 86 |
| 13 | Allocated Gas in Storage | | - | | - | | - |
| 14 | Total Liabilities per Financial Statements | $ | 54,166 | $ | 54,171 | $ | (5) |

* 2010 comparatives have been restated.

**FORTISBC ENERGY (WHISTLER) INC.** **1.7.0**
**ANNUAL REPORT - 2011**
**STATEMENT OF NET INCOME**

| Line No. | Particulars | Account No. | For the year ended Dec. 31/11 ($000) | For the year ended Dec. 31/10 ($000) | Increase (Decrease) ($000) |
|---|---|---|---|---|---|
| | Utility Income | | | | |
| 1 | Operating Revenue | 300 | $ 12,551 | $ 13,834 | $ (1,283) |
| 2 | Revenue from Gas Plant Leased to Others | 307 | | | - |
| 3 | Total Utility Operating Revenue | | $ 12,551 | $ 13,834 | $ (1,283) |
| | Operating Expense | | | | |
| 4 | Operating Expense including Cost of Gas | 301 | $ 7,228 | $ 8,082 | $ (854) |
| 5 | Maintenance Expense | 302 | - | 2 | (2) |
| 6 | Depreciation | 303 | 348 | 349 | (1) |
| 7 | Amortization | 304 | 940 | 1,509 | (569) |
| 8 | Municipal and Other Taxes | 305 | 278 | 285 | (7) |
| 9 | Income Taxes | 306 | 500 | 505 | (5) |
| 10 | Rent for Gas Plant Leased from Others | 308 | | | - |
| 11 | Total Utility Operating Expenses | | $ 9,294 | $ 10,732 | $ (1,438) |
| 12 | Net Utility Income | | $ 3,257 | $ 3,102 | $ 155 |
| | Other Income and Deductions | | | | |
| | Other Income | | | | |
| 13 | Revenue from Other Plant | 310 | | | $ - |
| 14 | Non-Operating Revenue | 312 | | | - |
| 15 | Income from Investments | 314 | | | - |
| 16 | Income from Investment in Affiliated Companies | 315 | | | - |
| 17 | Income from Sinking and Other Funds | 316 | | | - |
| 18 | Gain on Foreign Exchange | 317 | | | - |
| 19 | Other Income - Margin Volume Deferral | 319 | | | - |
| 20 | Allowance for Funds Used During Construction | 324 | 9 | 2 | 7 |
| 21 | Total Other Income | | $ 9 | $ 2 | $ 7 |
| | Other Income Deductions | | | | |
| 22 | Expense of Other Plant | 311 | | | $ - |
| 23 | Non-Operating Expense | 313 | | | - |
| 24 | Interest on Long Term Debt | 320 | 1,022 | 1,022 | - |
| 25 | Amortization of Debt Discount, Premium and Expense | 321 | | | - |
| 26 | Interest Due Affiliated Companies | 322 | | | - |
| 27 | Other Interest Expense | 323 | 236 | 211 | 25 |
| 28 | Loss on Foreign Exchange | 325 | | | - |
| 29 | Other Income Deductions | 329 | | | - |
| 30 | Total Other Income Deductions | | $ 1,258 | $ 1,233 | $ 25 |
| 31 | Income Before Extraordinary Items | | $ 2,008 | $ 1,871 | $ 137 |
| | Extraordinary Items | | | | |
| 32 | Extraordinary Income | 331 | | | $ - |
| 33 | Extraordinary Deductions | 332 | | | - |
| 34 | Net Extraordinary Items | | $ - | $ - | $ - |
| 35 | Net Income | 350 | $2,008 | $1,871 | $137 |
| 36 | Retained Earnings | | | | |
| 37 | Balance Beginning of Year | 212 | $ 4,799 | $ 3,996 | $ 803 |
| 38 | Balance Transferred from Net Income | 350 | 2,008 | 1,871 | 137 |
| 39 | Appropriations of Retained Earnings | 351 | | | - |
| 40 | Dividend Appropriations | 357 | (3,300) | - | (3,300) |
| 41 | Adjustments to Retained Earnings* | 359 | - | (1,068) | 1,068 |
| 42 | Retained Earnings End of Year* | 212 | $ 3,507 | $ 4,799 | $ (1,292) |

* 2010 comparatives have been restated.

**FORTISBC ENERGY (WHISTLER) INC.** **1.7.1**
**ANNUAL REPORT - 2011**
**RECONCILIATION OF FINANCIAL STATEMENT NET INCOME**
**TO ALLOWED EARNED RETURN ON EQUITY**

| Line No. | Particulars | Reference | 2011 ($000) | 2010 ($000) |
|---|---|---|---|---|
| 1 | NET INCOME PER FINANCIAL STATEMENTS | | $ 1,877 | $ 5,893 |
| 2 | Deferred Expense Adjustments Reported in 2009 (Net of Tax) | | - | (248) |
| 3 | Deferred Expense Adjustments Reported in 2010 (Net of Tax) | | 4 | (4) |
| 4 | Deferred Expense Adjustments Reported in 2011 (Net of Tax) | | 128 | - |
| 5 | Provision for Conversion Costs (Net of Tax) | | - | (3,769) |
| 6 | Rounding | | (1) | (1) |
| 7 | NET INCOME PER FINANCIAL STATEMENTS - Regulatory | 1.7.0 | $ 2,008 | $ 1,871 |
| | Add differences between Financial Statements and Regulatory: | | | |
| 8 | Difference in Total Taxes for Regulatory Purposes | | $ 19 | $ (154) |
| 9 | Previous Year Income Tax Adjustment | | - | - |
| 10 | Equity component of AFUDC | | (6) | (1) |
| 11 | Regulatory Cost Provisioning | | - | 9 |
| 12 | Difference in Total Interest for Regulatory Purposes | | (136) | - |
| 13 | Rounding | | (1) | (0) |
| 14 | ACTUAL EARNED RETURN ON EQUITY | 10.1.0 | $ 1,884 | $ 1,725 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**DEFERRED MATTERS**



| Line No. | Particulars | Balance **Dec 31, 2010** | Adjustment | Additions | Interest | Tax | Amortization | Balance at **Dec 31, 2011** | Mid-Year Balance |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Rate Base Deferrals** | | | | | | | | |
| 2 | **Margin Related** | | | | | | | | |
| 3 | Gas Cost Reconciliation Account (GCRA) | $ 11,492,149 | $ - | $ - | $ - | $ - | $ - | $ 11,492,149 | $ 11,492,149 |
| 4 | Cost of Gas - Rate Rider | (12,014,993) | - | 512,700 | - | (135,866) | - | (11,638,159) | (11,826,576) |
| 5 | Gas Cost Reconciliation Account (GCRA) - Net | (522,844) | - | 512,700 | - | (135,866) | - | (146,010) | (334,427) |
| 6 | Sales Margin Differential | 464,412 | - | - | - | - | - | 464,412 | 464,412 |
| 7 | Revenue Stabilization Adjustment Mechanism (RSAM) | 150,809 | - | 354,803 | - | (94,023) | - | 411,589 | 281,199 |
| 8 | RSAM/MCRA/CCRA/Gas in Storage Interest | 134 | - | (1,542) | - | 409 | - | (999) | (433) |
| 9 | Midstream Cost Reconciliation Account (MCRA) | 39,150 | - | (6,130) | - | 2,720 | - | 35,740 | 37,445 |
| 10 | Commodity Cost Reconciliation Account (CCRA) | (58,084) | - | (67,786) | - | 16,339 | - | (109,531) | (83,808) |
| 11 | **Whistler Pipeline and Conversion Costs** | | | | | | | | |
| 12 | Natural Gas Pipeline Development Costs | 1,792,823 | - | - | - | - | (94,300) | 1,698,523 | 1,745,673 |
| 13 | Decommissioning of Propane Assets | 4,408,489 | - | 72 | - | - | (225,005) | 4,183,556 | 4,296,023 |
| 14 | Capital Gain on Sale of Propane Land | 26,640 | - | - | - | - | 26,640 | 53,280 | 39,960 |
| 15 | Property Tax - Propane Plant | 53,261 | - | 53,100 | - | (14,071) | - | 92,289 | 72,775 |
| 16 | Capital Contribution to TGVI | 16,693,320 | - | - | - | - | (340,680) | 16,352,640 | 16,522,980 |
| 17 | Appliance Conversion Planning Costs | 694,912 | - | - | - | - | (35,085) | 659,827 | 677,370 |
| 18 | Direct Customer Appliance Conversion Costs | 7,611,801 | - | - | - | - | (386,500) | 7,225,301 | 7,418,551 |
| 19 | **Non Controllable Items** | | | | | | | | |
| 20 | Interest Rate Differential | (311,656) | - | (142,986) | - | 37,891 | - | (416,751) | (364,204) |
| 21 | Property Tax Differential | (1,810) | - | (7,458) | - | 1,976 | - | (7,292) | (4,551) |
| 22 | IFRS Implementation Costs | 8,242 | - | 4,694 | - | (1,244) | (2,000) | 9,692 | 8,967 |
| 23 | 2010 Olympic Games Security Costs | 13,347 | - | - | - | - | (9,100) | 4,247 | 8,797 |
| 24 | Income Tax Variance | (1,788) | - | 1,802 | - | - | - | 14 | (887) |
| 25 | IFRS Transitional Adjustments | (58,069) | - | 152 | - | - | - | (57,917) | (57,993) |
| 26 | Gains and Losses on Asset Disposition | 132,125 | - | 111,945 | - | - | - | 244,070 | 188,098 |
| 27 | Deferred Removal Costs | 3,464 | - | 8,182 | - | (2,149) | - | 9,497 | 6,481 |
| 28 | US GAAP Conversion Costs | - | - | 2,539 | - | (673) | - | 1,866 | 933 |
| 29 | **Cost of Current Applications** | | | | | | | | |
| 30 | 2010-2011 Revenue Requirements Application | 297,751 | - | 1,324 | - | (351) | (35,250) | 263,474 | 280,613 |
| 31 | 2009 ROE and Capital Structure Application | 5,982 | - | 310 | - | (82) | (980) | 5,230 | 5,606 |
| 32 | CCE CPCN Application | 2,682 | - | - | - | - | (420) | 2,262 | 2,472 |
| 33 | 2012 Revenue Requirement Application | - | - | 11,863 | - | (3,144) | - | 8,719 | 4,360 |
| 34 | **Residual Deferred Charges** | | | | | | | | |
| 35 | Deferred ROE Variance (2005-2009) | (209,869) | - | - | - | - | 162,800 | (47,069) | (128,469) |
| 36 | 2009 Revenue Requirements Application | 947 | - | - | - | - | - | 947 | 947 |
| 37 | **Total Rate Base Deferrals** | 31,236,171 | - | 837,586 | - | (192,268) | (939,880) | 30,941,606 | 31,088,890 |
| 38 | **Non-Rate Base Deferrals** | | | | | | | | |
| 39 | CCE Project O&M Costs | 4,941 | - | 43,488 | 1,305 | (11,386) | - | 38,348 | 21,645 |
| 40 | IFRS Revenue Requirement Adjustment | 6,000 | - | (6,000) | - | - | - | - | 3,000 |
| 41 | Amalgamation Costs | - | - | 837 | - | - | - | 837 | 419 |
| 42 | 2012 Rate Design Application | - | - | 3,979 | 113 | (1,046) | - | 3,047 | 1,524 |
| 43 | **Total Non-Rate Base Deferrals** | 10,941 | - | 42,304 | 1,418 | (12,432) | - | 42,232 | 26,588 |
| 44 | **Total Deferrals** | $ 31,247,112 | $ - | $ 879,890 | $ 1,418 | $ (204,699) | $ (939,880) | $ 30,983,838 | $ 31,115,478 |

**FORTISBC ENERGY (WHISTLER) INC.** **1.9.0**
**ANNUAL REPORT - 2011**
**LEASE / RENTAL PAYMENTS CHARGED TO OPERATING EXPENSES**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Office / Warehouse | $ 28,175 | $ 28,563 | $ (388) |
| 2 | Vehicle | - | - | - |
| 3 | Other | - | - | - |
| 4 | Total | $ 28,175 | $ 28,563 | $ (388) |

**FORTISBC ENERGY (WHISTLER) INC.** **2.0.0**
**ANNUAL REPORT - 2011**
**GROSS GAS PLANT IN SERVICE**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Intangible Plant | $ 95,226 | $ 95,226 | $ - |
| 2 | Manufactured Gas Plant | 898,701 | 898,701 | - |
| 3 | Local Storage | - | - | - |
| 4 | Transmission | - | - | - |
| 5 | Distribution | 15,552,600 | 15,120,472 | 432,128 |
| 6 | General Plant | 478,040 | 479,565 | (1,526) |
| 7 | TOTAL GAS PLANT IN SERVICE | $ 17,024,567 | $ 16,593,964 | $ 430,603 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**GROSS PLANT IN SERVICE**

| Line No. | Account No. | Particulars | Balance (Net of WIP) @ Dec 31/2010 | 2010 WIP | 2011 Additions | 2011 Adjustments | 2011 Retirements | 2011 Overhead Allocation | 2011 AFUDC Allocation | Gross Plant @ Dec 31/2011 | 2011 WIP | Total Net Plant @ Dec 31/2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 401 | Franchise & Consents | $ 8,239 | $ - | $ - | $ - | $ - | $ - | $ - | $ 8,239 | $ - | $ 8,239 |
| 2 | 402 | Other Intangible Plant | - | 55,334 | 72,309 | - | - | - | 5,580 | 133,224 | (133,224) | - |
| 3 | 175 | Unamortized Conversion Expense | - | - | - | - | - | - | - | - | - | - |
| 4 | 431 | Land Rights | 86,987 | - | - | - | - | - | - | 86,987 | - | 86,987 |
| 5 | **Total Intangible Plant** | | 95,226 | 55,334 | 72,309 | - | - | - | 5,580 | 228,450 | (133,224) | 95,226 |
| 6 | 430 | Land | 898,701 | - | - | - | - | - | - | 898,701 | - | 898,701 |
| 7 | 431 | Land Rights | - | - | - | - | - | - | - | - | - | - |
| 8 | 432 | Structure & Improvements | - | - | - | - | - | - | - | - | - | - |
| 9 | 433 | Manufacturing Equipment | - | - | - | - | - | - | - | - | - | - |
| 10 | 434 | Gas Holders | - | - | - | - | - | - | - | - | - | - |
| 11 | 436 | Compressor Equipment | - | - | - | - | - | - | - | - | - | - |
| 12 | 437 | Meas & Reg Equipment | - | - | - | - | - | - | - | - | - | - |
| 13 | 438 | Purification Equipment | - | - | - | - | - | - | - | - | - | - |
| 14 | **Total Manufactured Gas Plant** | | 898,701 | - | - | - | - | - | - | 898,701 | - | 898,701 |
| 15 | 470 | Land | - | - | - | - | - | - | - | - | - | - |
| 16 | 471 | Land Rights | - | - | - | - | - | - | - | - | - | - |
| 17 | 472 | Structures & Improvements | 1,617 | - | - | - | - | - | - | 1,617 | - | 1,617 |
| 18 | 473 | Services | 3,888,564 | 6,434 | 115,562 | - | (32,337) | 29,250 | - | 4,007,474 | (4,053) | 4,003,421 |
| 19 | 474 | Meter & Regulator Installation | 1,401,865 | 10,581 | 48,707 | - | - | 12,025 | - | 1,473,178 | (10,799) | 1,462,380 |
| 20 | 475 | Mains | 8,723,443 | 668 | 323,370 | - | (133,745) | 80,196 | - | 8,993,933 | (668) | 8,993,264 |
| 21 | 476 | Compressor Equipment | 0 | - | - | - | - | - | - | 0 | - | 0 |
| 22 | 477 | Measuring & Reg. Equipment | 642,542 | - | 307 | - | - | 76 | - | 642,925 | - | 642,925 |
| 23 | 478 | Meters | 462,440 | - | - | (13,448) | - | - | - | 448,993 | - | 448,993 |
| 24 | 478 | Meter Set Installation | - | - | - | - | - | - | - | - | - | - |
| 25 | **Total Distribution Plant** | | 15,120,472 | 17,683 | 487,947 | (13,448) | (166,082) | 121,548 | - | 15,568,120 | (15,520) | 15,552,600 |
| 26 | 480 | Land | - | - | - | - | - | - | - | - | - | - |
| 27 | 481 | Land Rights | - | - | - | - | - | - | - | - | - | - |
| 28 | 482 | Structures & Improvements | 17,236 | 23,450 | 13,231 | - | - | - | 2,087 | 56,003 | (38,767) | 17,236 |
| 29 | 483 | Office Furniture & Equipment | 7,951 | 839 | 12,973 | 740 | (2,447) | - | 257 | 20,313 | (9,069) | 11,244 |
| 30 | 483 | Systems - MIS | 740 | - | - | (740) | - | - | - | - | - | - |
| 31 | 483 | Systems - CSS | - | 1,503 | 609 | - | - | - | (30) | 2,082 | (2,082) | - |
| 32 | 483 | Computer Equipment | - | 2,633 | 12,212 | - | - | - | 383 | 15,228 | (15,228) | - |
| 33 | 484 | Transportation Equipment | 154,309 | - | - | - | - | - | - | 154,309 | - | 154,309 |
| 34 | 485 | Heavy Work Equipment | 95,256 | - | - | - | (3,290) | - | - | 91,966 | - | 91,966 |
| 35 | 486 | Tools & Work Equipment | 188,447 | - | 17,300 | - | (10,914) | - | - | 194,833 | - | 194,833 |
| 36 | 487 | Equip. on Customer Premises | - | - | - | - | - | - | - | - | - | - |
| 37 | 488 | Communications Equipment | 15,627 | 82 | 6 | - | (7,174) | - | 5 | 8,546 | (93) | 8,453 |
| 38 | 499 | Plant Suspense | - | 5,419 | 1,838 | - | - | - | - | 7,256 | (7,256) | - |
| 39 | **Total General Plant** | | 479,565 | 33,925 | 58,169 | - | (23,826) | - | 2,701 | 550,535 | (72,495) | 478,040 |
| 40 | **TOTAL PLANT** | | $ 16,593,964 | $ 106,943 | $ 618,424 | $ (13,448) | $ (189,908) | $ 121,548 | $ 8,282 | $ 17,245,806 | $ (221,239) | $ 17,024,567 |

**FORTISBC ENERGY (WHISTLER) INC.** **2.2.0**
**ANNUAL REPORT - 2011**
**GROSS GAS PLANT IN SERVICE VARIANCE**

| Line No. | | 2011 Year End Balance | 2010 Year End Balance | Increase (Decrease) |
|---|---|---|---|---|
| 1 | **Manufactured Gas Plant** | $ 898,701 | $ 898,701 | $ - |
| 2 | **Distribution** | $ 15,552,600 | $ 15,120,472 | $ 432,128 |
| 3 | FEW added 3 km of mains in 2011 to support 57 additional customers. | | | |
| 4 | **General Plant** | $ 478,040 | $ 479,565 | $ (1,526) |
| 5 | FEW retired office equipment and telephone equipment. | | | |

**FORTISBC ENERGY (WHISTLER) INC.** **2.3.0**
**ANNUAL REPORT - 2011**
**GAS PLANT UNDER CONSTRUCTION & HELD FOR FUTURE USE (GPHFFU)**

| Line No. | | As At Dec. 31/11 | As At Dec. 31/10 | Increase (Decrease) |
|---|---|---|---|---|
| | GAS PLANT UNDER CONSTRUCTION | | | |
| 1 | Direct Costs | $ 211,701 | $ 105,687 | $ 106,015 |
| 2 | Overhead Allocation | - | - | - |
| 3 | AFUDC | 9,538 | 1,256 | 8,282 |
| 4 | Total Gas Plant Under Construction | $ 221,239 | $ 106,943 | $ 114,296 |
| | GAS PLANT HELD FOR FUTURE USE | | | |
| 5 | Direct Costs | $ - | $ - | $ - |
| 6 | Overhead Allocation | - | - | - |
| 7 | AFUDC | - | - | - |
| 8 | Total Gas Plant Held for Future Use | $ - | $ - | $ - |

Note: Allowance for Funds Utilized During Construction (AFUDC)

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**CONSTRUCTION OVERHEADS (Direct & Indirect & AFUDC)**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Overheads and AFUDC in Opening GPHFFU & Opening CWIP | $ 1,256 | $ - | $ 1,256 |
| 2 | AFUDC allocated to deferrals | - | - | - |
| 3 | Overheads and AFUDC Additions during year | 129,830 | 120,062 | 9,768 |
| 4 | Overheads and AFUDC in Closing GPHFFU & Closing CWIP | 9,538 | 1,256 | 8,282 |
| 5 | Total Overheads and AFUDC Cleared to Plant in Service | $ 121,548 | $ 118,806 | $ 2,742 |
| 6 | Cost of Construction | $ 487,947 | $ 376,863 | $ 111,084 |
| 7 | % Overheads to Construction | 24.9% | 31.5% | -6.6% |

**TERASEN GAS (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)**



| Line No. | Particulars | Opening Balance | 2011 Additions | 2011 Adjustments | 2011 Retirements | Ending Balance |
|---|---|---|---|---|---|---|
| 1 | **CIAC** | | | | | |
| 2 | Distribution Contributions | $ (186,195) | $ (15,595) | $ - | $ - | $ (201,790) |
| 3 | | | | | | |
| 4 | **Total Contributions** | (186,195) | (15,595) | - | - | (201,790) |
| 5 | | | | | | |
| 6 | **Amortization** | | | | | |
| 7 | Distribution Contributions | $ 11,677 | $ 4,909 | $ - | $ - | $ 16,586 |
| 8 | | | | | | |
| 9 | **Total Amortization** | 11,677 | 4,909 | - | - | 16,586 |
| 10 | | | | | | |
| 11 | **NET CONTRIBUTIONS** | **$ (174,518)** | **$ (10,686)** | **$ -** | **$ -** | **$ (185,204)** |

**FORTISBC ENERGY (WHISTLER) INC.** **3.0.0**
**ANNUAL REPORT - 2011**
**ACCUMULATED DEPRECIATION**

| Line No. | Particulars | | 2011 | | 2010 | | (Increase) Decrease |
|---|---|---|---|---|---|---|---|
| 1 | Intangible Plant | $ | (12,670) | $ | (12,332) | $ | (339) |
| 2 | Manufactured Gas Plant | | - | | - | | - |
| 3 | Local Storage | | - | | - | | - |
| 4 | Transmission | | - | | - | | - |
| 5 | Distribution | | (3,145,423) | | (2,893,139) | | (252,284) |
| 6 | General Plant | | (278,264) | | (262,283) | | (15,981) |
| 7 | TOTAL ACCUMULATED DEPRECIATION | $ | (3,436,358) | $ | (3,167,754) | $ | (268,603) |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**Accumulated Depreciation**



| Line No. | Account No | Particulars | 2011 Mid-Year Net Additions | Deprec. Rate | Accumulated Depreciation @ Dec 31/2010 | 2011 Depreciation Expense | 2011 Adjustments | 2011 Retirements | Accumulated Depreciation @ Dec 31/2011 |
|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 1 | 501 | Franchise & Consents | $8,239 | 4.11% | ($2,147) | ($339) | $0 | $0 | ($2,485) |
| 2 | 502 | Other Intangible Plant | - | 0.00% | - | - | - | - | - |
| 3 | 531 | Land Rights | 86,987 | 0.00% | (10,185) | - | - | - | (10,185) |
| 4 | **Total Intangible Plant** | | 95,226 | | (12,332) | (339) | - | - | (12,670) |
| 5 | 530 | Land | 898,701 | | - | - | - | - | - |
| 6 | 531 | Land Rights | - | 0.00% | - | - | - | - | - |
| 7 | 532 | Structure & Improvements | - | 2.50% | - | - | - | - | - |
| 8 | 533 | Manufacturing Equipment | - | 14.35% | - | - | - | - | - |
| 9 | 534 | Gas Holders | - | 2.74% | - | - | - | - | - |
| 10 | 536 | Compressor Equipment | - | 5.18% | - | - | - | - | - |
| 11 | 537 | Meas & Reg Equipment | - | 13.16% | - | - | - | - | - |
| 12 | 538 | Purification Equipment | - | 0.00% | - | - | - | - | - |
| 13 | **Total Manufactured Gas Plant** | | 898,701 | | - | - | - | - | - |
| 14 | 570 | Land | - | | - | - | - | - | - |
| 15 | 571 | Land Rights | - | 0.00% | - | - | - | - | - |
| 16 | 572 | Structures & Improvements | 1,617 | 3.26% | (93) | (53) | - | - | (146) |
| 17 | 573 | Services | 3,945,993 | 1.94% | (666,898) | (75,501) | - | 5,049 | (737,350) |
| 18 | 574 | Meter & Regulator Installation | 1,432,122 | 3.33% | (338,356) | (47,257) | - | - | (385,612) |
| 19 | 575 | Mains | 8,858,354 | 1.66% | (1,749,105) | (145,075) | - | 50,618 | (1,843,562) |
| 20 | 576 | Compressor Equipment | 0 | 0.00% | - | - | - | - | - |
| 21 | 577 | Measuring & Reg. Equipment | 642,734 | 4.60% | (31,861) | (29,570) | - | - | (61,431) |
| 22 | 578 | Meters | 455,716 | 4.66% | (106,826) | (22,000) | 11,505 | - | (117,322) |
| 23 | 578 | Meter Set Installation | - | 0.00% | - | - | - | - | - |
| 24 | **Total Distribution Plant** | | 15,336,536 | | (2,893,139) | (319,456) | 11,505 | 55,668 | (3,145,423) |
| 25 | 580 | Land | - | | - | - | - | - | - |
| 26 | 581 | Land Rights | - | 0.00% | - | - | - | - | - |
| 27 | 582 | Structures & Improvements | 17,236 | 4.41% | (1,941) | (657) | - | - | (2,598) |
| 28 | 583 | Office Furniture & Equipment | 9,598 | 6.67% | (5,684) | 133 | (153) | 2,039 | (3,664) |
| 29 | 583 | Systems - MIS | 370 | 0.00% | - | - | - | - | - |
| 30 | 583 | Systems - CSS | - | 0.00% | - | - | - | - | - |
| 31 | 583 | Computer Equipment | - | 20.00% | - | - | - | - | - |
| 32 | 584 | Transportation Equipment | 154,309 | 16.01% | (60,978) | (24,705) | - | - | (85,683) |
| 33 | 585 | Heavy Work Equipment | 93,611 | 4.63% | (67,885) | (4,300) | - | 3,290 | (68,894) |
| 34 | 586 | Tools & Work Equipment | 191,640 | 5.00% | (113,341) | (9,494) | - | 10,914 | (111,921) |
| 35 | 587 | Equip. on Customer Premises | - | 0.00% | - | - | - | - | - |
| 36 | 588 | Communications Equipment | 12,040 | 6.67% | (12,455) | 972 | - | 5,978 | (5,504) |
| 37 | **Total General Plant** | | 478,803 | | (262,283) | (38,050) | (153) | 22,222 | (278,264) |
| 38 | **TOTAL PLANT** | | $16,809,266 | | ($3,167,754) | ($357,845) | $11,352 | $77,890 | ($3,436,358) |
| 39 | | Less: Vehicle depreciation allocated to capital | | | | 4,708 | | | |
| 40 | | | | | | ($353,137) | | | |

## FORTISBC ENERGY (WHISTLER) INC.
## ANNUAL REPORT - 2011
## GAS ACCOUNT
## GJs of Gas as Measured



| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | GAS RECEIVED [1] | | | |
| 1 | Natural Gas | 736,844 | 753,193 | (16,349) |
| 2 | Total Receipts | 736,844 | 753,193 | (16,349) |
| | GAS DELIVERED | | | |
| 3 | Sales to Ultimate Customers - Natural Gas | 736,844 | 753,195 | (16,351) |
| 4 | Total Deliveries | 736,844 | 753,195 | (16,351) |
| 5 | Natural Gas Receipts less Deliveries | 0 | (2) | 2 |
| 6 | Total Gas Receipts less Deliveries | 0 | (2) | 2 |
| 7 | % Natural Gas Unaccounted | 0.00% | 0.00% | 0.00% |
| 8 | Total % Unaccounted | 0.00% | 0.00% | 0.00% |
| 9 | Total Cost of Gas Sold ($) | $4,156,093 | $4,985,961 | ($829,868) |
| 10 | Total Cost of Gas Sold ($/GJ) | $5.64 | $6.62 | ($0.98) |

[1] Excluding own use gas.

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**ACTUAL GAS SALES, REVENUE AND CUSTOMERS**

| Line No. | Particulars | Residential $ | Residential GJ | Commercial $ | Commercial GJ | Industrial $ | Industrial GJ | Total $ | Total GJ |
|---|---|---|---|---|---|---|---|---|---|
| | GAS SALES & REVENUE | | | | | | | | |
| | Distribution: | | | | | | | | |
| 1 | 2011 Year End | $ 3,841,786 | 221,686 | $ 8,334,169 | 515,158 | $ - | - | $ 12,175,955 | 736,844 |
| 2 | 2010 Year End | $ 4,176,571 | 218,386 | $ 9,410,275 | 534,809 | $ - | - | $ 13,586,846 | 753,195 |
| 3 | Increase (Decrease) | $ (334,785) | 3,300 | $ (1,076,106) | (19,651) | $ - | - | $ (1,410,891) | (16,351) |

| | | Residential 2011 Year End | Residential 2010 Year End | Commercial 2011 Year End | Commercial 2010 Year End | Industrial 2011 Year End | Industrial 2010 Year End | Total 2011 Year End | Total 2010 Year End |
|---|---|---|---|---|---|---|---|---|---|
| | CUSTOMERS | | | | | | | | |
| | Distribution: | | | | | | | | |
| 4 | Year End | 2,296 | 2,262 | 353 | 330 | - | - | 2,649 | 2,592 |
| 5 | Average | 2,279 | 2,256 | 342 | 330 | - | - | 2,621 | 2,586 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**OTHER REVENUE**



| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Penalty Revenue | $ 820 | $ 430 | $ 390 |
| 2 | Connection Charge Revenue | 1,855 | 4,000 | (2,145) |
| 3 | LPC Revenue | 19,580 | 19,090 | 490 |
| 4 | Service Work | - | - | - |
| 5 | NSP Provision* | (6,000) | 6,000 | (12,000) |
| 6 | Miscellaneous* | 3,920 | 6,378 | (2,458) |
| 7 | Total Other Revenue | $20,175 | $35,898 | ($15,723) |

* 2010 comparative figures have been restated.

# FORTISBC ENERGY (WHISTLER) INC.
## ANNUAL REPORT - 2011
## TEMPERATURE NORMALIZATION ADJUSTMENT



| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | Degree Day Information | | | |
| 1 | Actual Degree Days | 4,190.7 | 4,095.0 | 95.7 |
| 2 | Normal Average Degree Days | 4,051.1 | 4,068.1 | (17.0) |
| 3 | Difference | 139.6 | 26.9 | 112.7 |
| 4 | % Change = Difference/Normal Average | 3.45% | 0.66% | 2.78% |
| | Effect on Sales Volume (GJ): | | | |
| 5 | Residential | (6,705) | 5,754 | (12,459) |
| 6 | Commercial | (9,386) | 6,534 | (15,920) |
| 7 | Industrial | | | |
| 8 | Total Sales Volume [1] | (16,091) | 12,288 | (28,379) |
| | Effect on Sales Revenue ($): | | | |
| 9 | Residential | ($116,664) | $111,989 | ($228,653) |
| 10 | Commercial | (150,635) | 109,587 | (260,222) |
| 11 | Industrial | | | |
| 12 | Total Sales Revenue | ($267,299) | $221,577 | ($488,875) |
| | Effect on Purchases: | | | |
| 13 | Volume (GJ) [1] | (11,521) | 27,036 | (38,558) |
| 14 | Cost of Gas ($) | ($64,986) | $179,157 | ($244,143) |
| 15 | Net Effect on Gross Margin ($): | ($202,313) | $42,419 | ($244,733) |

| Line No. | Note: | UAF |
|---|---|---|
| 16 | 1. 2011 normalized UAF | |
| 17 | 2009 | 1.88% |
| 18 | 2010 | 0.00% |
| 19 | 2011 | 0.00% |
| 20 | Rolling 3-year average | 0.63% |

| Line No. | | Actual GJs | Normalized GJs | Normalized Effect |
|---|---|---|---|---|
| 21 | Purchase Volume | 736,844 | 725,323 | (11,521) |
| 22 | Sales Volume | 736,844 | 720,753 | (16,091) |
| 23 | UAF Volume | - | 4,570 | |
| 24 | UAF % | 0.00% | 0.63% | |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**OPERATING & MAINTENANCE EXPENSES - SUMMARY**

| Line No. | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| 1 | Total Gross O&M Expenses* | 803,252 | $772,638 | $30,615 |
| 2 | Capitalization | (121,550) | (118,806) | (2,744) |
| 3 | TOTAL NET DIRECT O&M EXPENSES | $681,702 | $653,832 | $27,871 |
| 4 | Average Employee Count | 2.00 | 1.83 | 0.17 |

**ANNUAL REPORT - 2011**

**OPERATING AND MAINTENANCE EXPENSES (Resource View)**

| | Particulars | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| 1 | M&E Costs | $15,035 | $59,118 | ($44,083) |
| 2 | COPE Costs | 4,695 | 1,216 | 3,478 |
| 3 | IBEW Costs | 199,697 | 211,673 | (11,976) |
| 4 | **Labour Costs** | **$219,427** | **$272,007** | **($52,580)** |
| 5 | Vehicle costs | $17,747 | $28,295 | ($10,548) |
| 6 | Employee Expenses | 6,813 | (17,051) | 23,865 |
| 7 | Materials and Supplies | 8,195 | 20,815 | (12,620) |
| 8 | Computer Costs and Office Furniture | 541 | 1,304 | (763) |
| 9 | Fees & Admin, Promotion & Advertising | 360,427 | 289,010 | 71,417 |
| 10 | Contractors costs | 154,230 | 133,289 | 20,941 |
| 11 | Facilities | 44,010 | 59,293 | (15,282) |
| 12 | Recoveries & Revenue | (8,138) | (14,324) | 6,186 |
| 13 | **Non-Labour Costs** | **$583,826** | **$500,631** | **$83,195** |
| 14 | **Total Gross O&M Expense** | **$803,252** | **$772,638** | **$30,615** |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**OPERATING AND MAINTENANCE EXPENSES (Activity View)**

| Line No. | Particulars | Reference | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| 1 | Distribution - Supervision* | 100-10 | $90,938 | $150,636 | (59,698) |
| 2 | Distribution - Operation | 100-20 | 157,758 | 137,965 | 19,793 |
| 3 | Distribution - Maintenance | 100-30 | 51,556 | 46,334 | 5,221 |
| 4 | **Distribution Total** | **100** | **300,252** | **334,935** | **(34,684)** |
| 5 | Measurement Operations | 400-10 | 9,613 | 9,461 | 152 |
| 6 | Measurement Maintenance | 400-20 | - | - | - |
| 7 | **Measurement Total** | **400** | **9,613** | **9,461** | **152** |
| 8 | Customer Contact - ABSU contract* | 700-20 | 151,493 | 125,195 | 26,298 |
| 9 | Bad Debt Management and Administration | 700-30 | 23,480 | 21,494 | 1,986 |
| 10 | **Customer Care Total** | **700** | **174,973** | **146,689** | **28,284** |
| 11 | Business & IT - Supervision* | 800-10 | - | - | - |
| 12 | **Business & IT Services** | **800** | **-** | **-** | **-** |
| 13 | Shared Services Allocation and Direct Charges | 900-14 | 261,147 | 250,660 | 10,487 |
| 14 | Administration & General - inc insurance* | 900-11 | 57,268 | 30,893 | 26,375 |
| 15 | **Administration & General Total** | **900** | **318,415** | **281,553** | **36,862** |
| 16 | **Total Gross O&M Expense** | | **$803,252** | **$772,638** | **$30,615** |

* 2010 comparative figures have been re-classed.

# FORTISBC ENERGY (WHISTLER) INC.
## ANNUAL REPORT - 2011
## PIPELINE METRES - DISTRIBUTION MAINS



| Line No. | Pipe Size mm | 2011 | | | | | |
|---|---|---|---|---|---|---|---|
| | | Plastic | Steel | HP Steel | MOPP | P. Sys Bet. | Total |
| 1 | 33-48 | 17,537 | - | - | 1,641 | 23 | 19,201 |
| 2 | 60 | 22,933 | 331 | - | 1,416 | (118) | 24,562 |
| 3 | 88 | 8,446 | 298 | - | - | 508 | 9,252 |
| 4 | 114 | 30,196 | 511 | 1,376 | 263 | 428 | 32,774 |
| 5 | 168 | 25 | 1,128 | - | - | 840 | 1,993 |
| 6 | 219 | - | 540 | - | - | 9,469 | 10,009 |
| 7 | 273 | - | - | - | - | - | - |
| 8 | 323 | - | - | - | - | - | - |
| 9 | Total | 79,137 | 2,808 | 1,376 | 3,320 | 11,150 | 97,791 |

| | | 2010 | | | | | |
|---|---|---|---|---|---|---|---|
| | | Plastic | Steel | HP Steel | MOPP | P. Sys Bet. | Total |
| 10 | 33-48 | 17,313 | - | - | 1,641 | 23 | 18,977 |
| 11 | 60 | 21,023 | 331 | - | 1,416 | (118) | 22,652 |
| 12 | 88 | 8,446 | 298 | - | - | 508 | 9,252 |
| 13 | 114 | 29,421 | 488 | 1,376 | 263 | 428 | 31,976 |
| 14 | 168 | 25 | 1,128 | - | - | 840 | 1,993 |
| 15 | 219 | - | 540 | - | - | 9,469 | 10,009 |
| 16 | 273 | - | - | - | - | - | - |
| 17 | 323 | - | - | - | - | - | - |
| 18 | Total | 76,228 | 2,785 | 1,376 | 3,320 | 11,150 | 94,859 |

| | | Additions | | | | | |
|---|---|---|---|---|---|---|---|
| | | Plastic | Steel | HP Steel | MOPP | P. Sys Bet. | Total |
| 19 | 33-48 | 224 | - | - | - | - | 224 |
| 20 | 60 | 1,910 | - | - | - | - | 1,910 |
| 21 | 88 | - | - | - | - | - | - |
| 22 | 114 | 775 | 23 | - | - | - | 798 |
| 23 | 168 | - | - | - | - | - | - |
| 24 | 219 | - | - | - | - | - | - |
| 25 | 273 | - | - | - | - | - | - |
| 26 | 323 | - | - | - | - | - | - |
| 27 | Total | 2,909 | 23 | - | - | - | 2,932 |

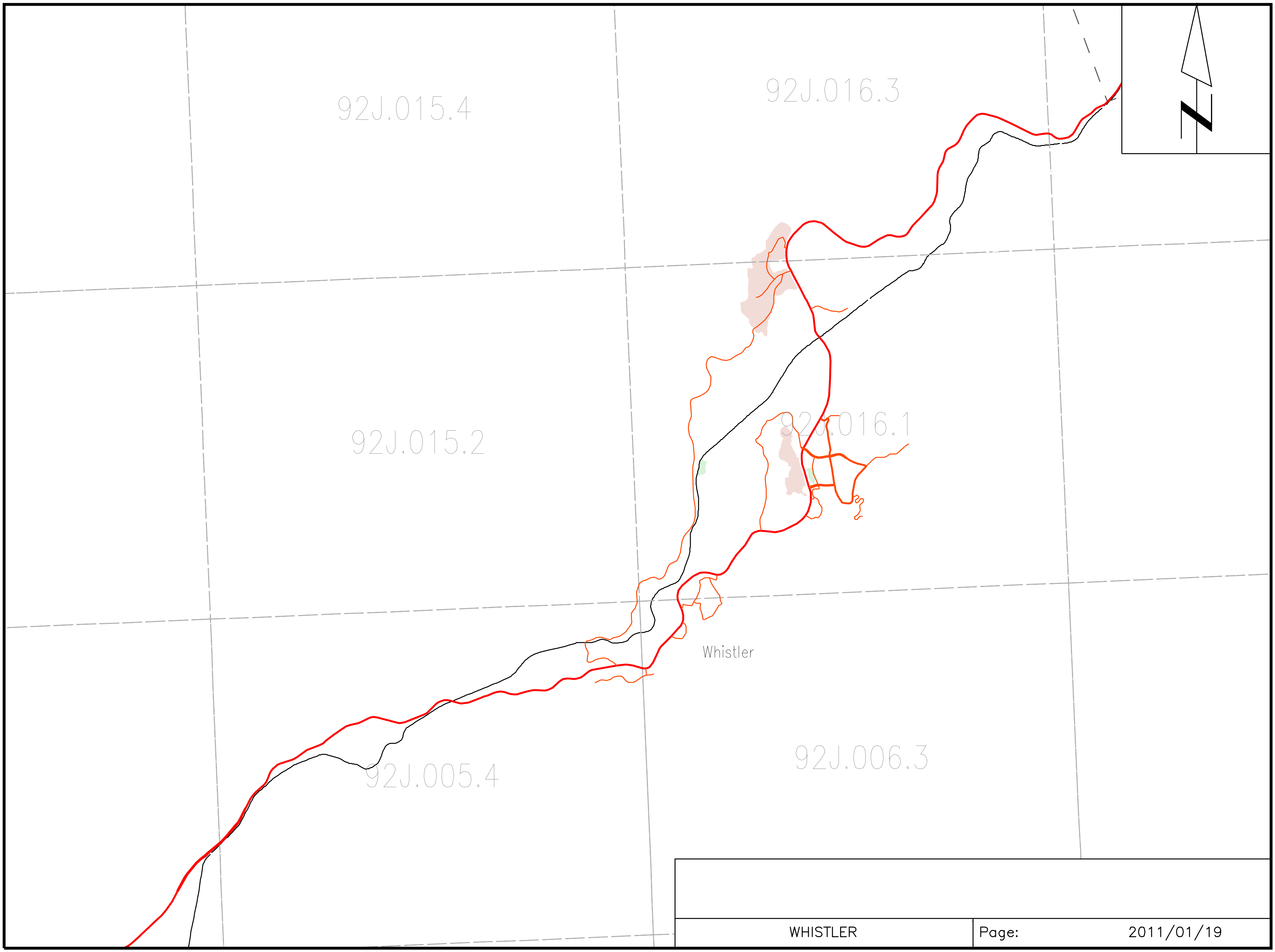
**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**SERVICE INTERRUPTIONS AND PROPERTY DAMAGE**

## 1. Service Interruptions

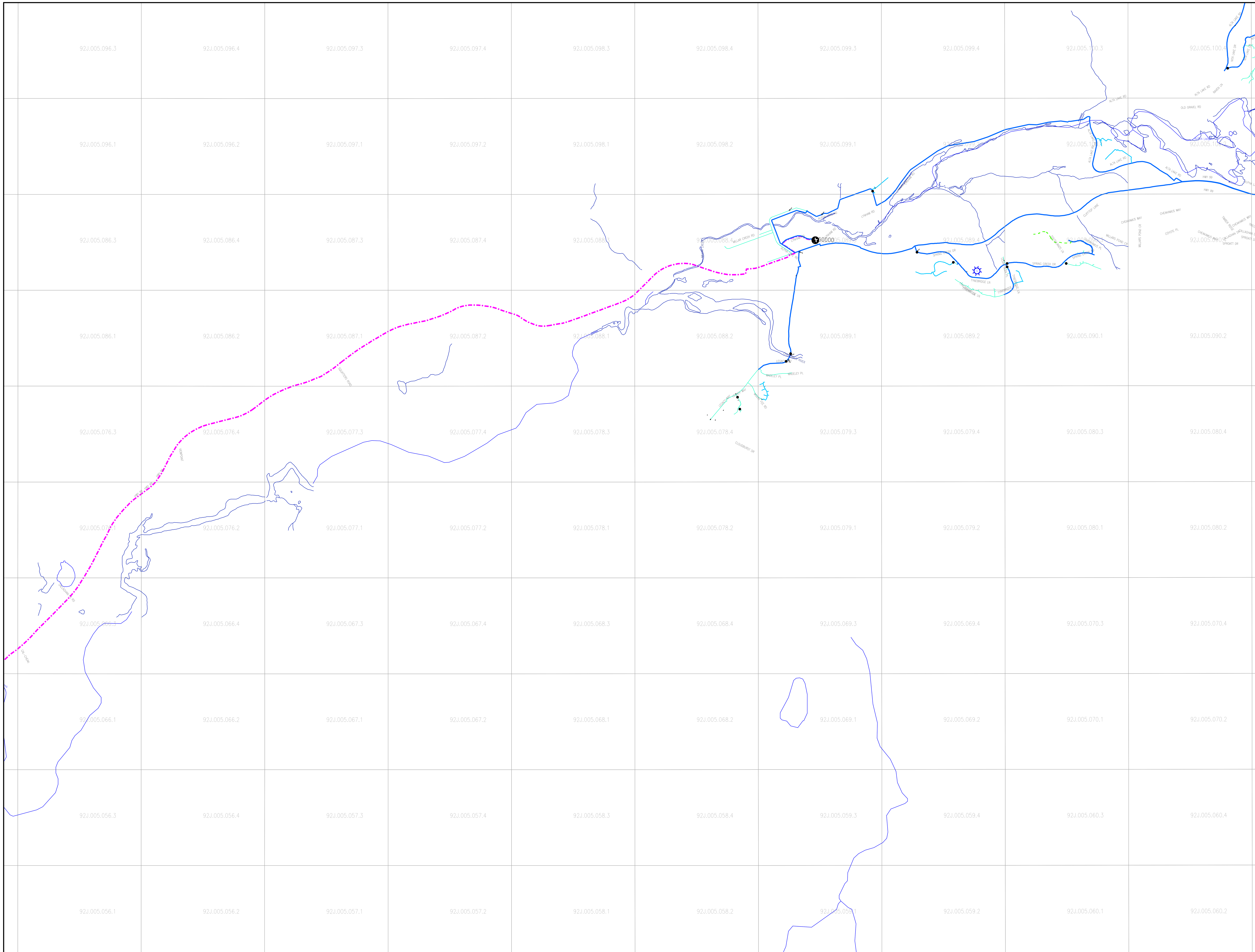
There were no important interruptions of service due to failure of the utility's facilities or failure of our gas supply in 2011.

## 2. Damage/Injury

No significant property and personal injury claims were filed.




WHISTLER | Page: | 2011/01/19



Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

DATE LAST REVISED

2011/01/19

PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

| | | |
|---|---|---|
| 92J.015.1 | 92J.015.2 | 92J.016.1 |
| 92J.005.3 | 92J.005.4 | 92J.006.3 |
| 92J.005.1 | 92J.005.2 | 92J.006.1 |


Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

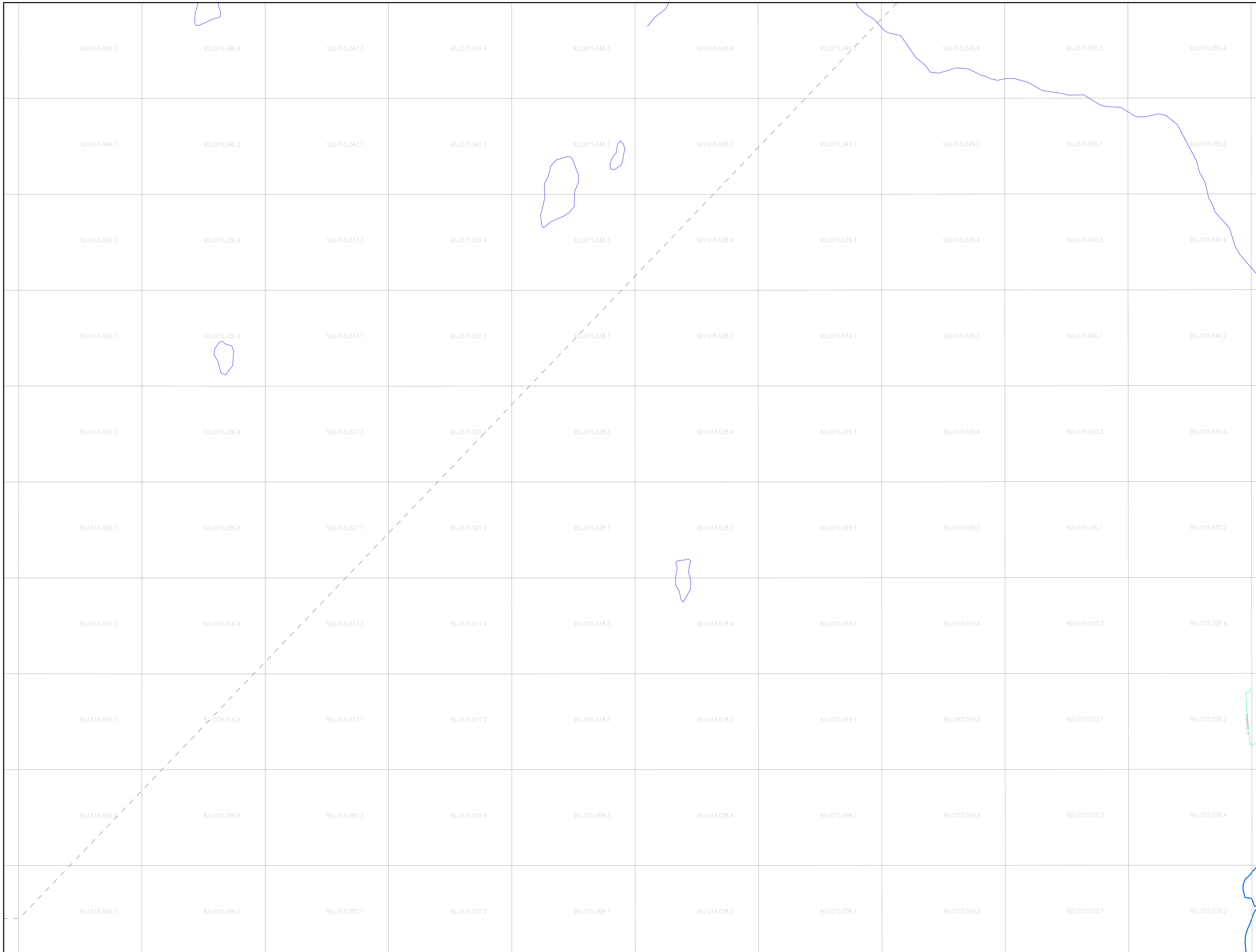
PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

| | | |
|---|---|---|
| 92J.015.2 | 92J.016.1 | 92J.016.2 |
| 92J.005.4 | 92J.006.3 | 92J.006.4 |
| 92J.005.2 | 92J.006.1 | 92J.006.2 |




Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

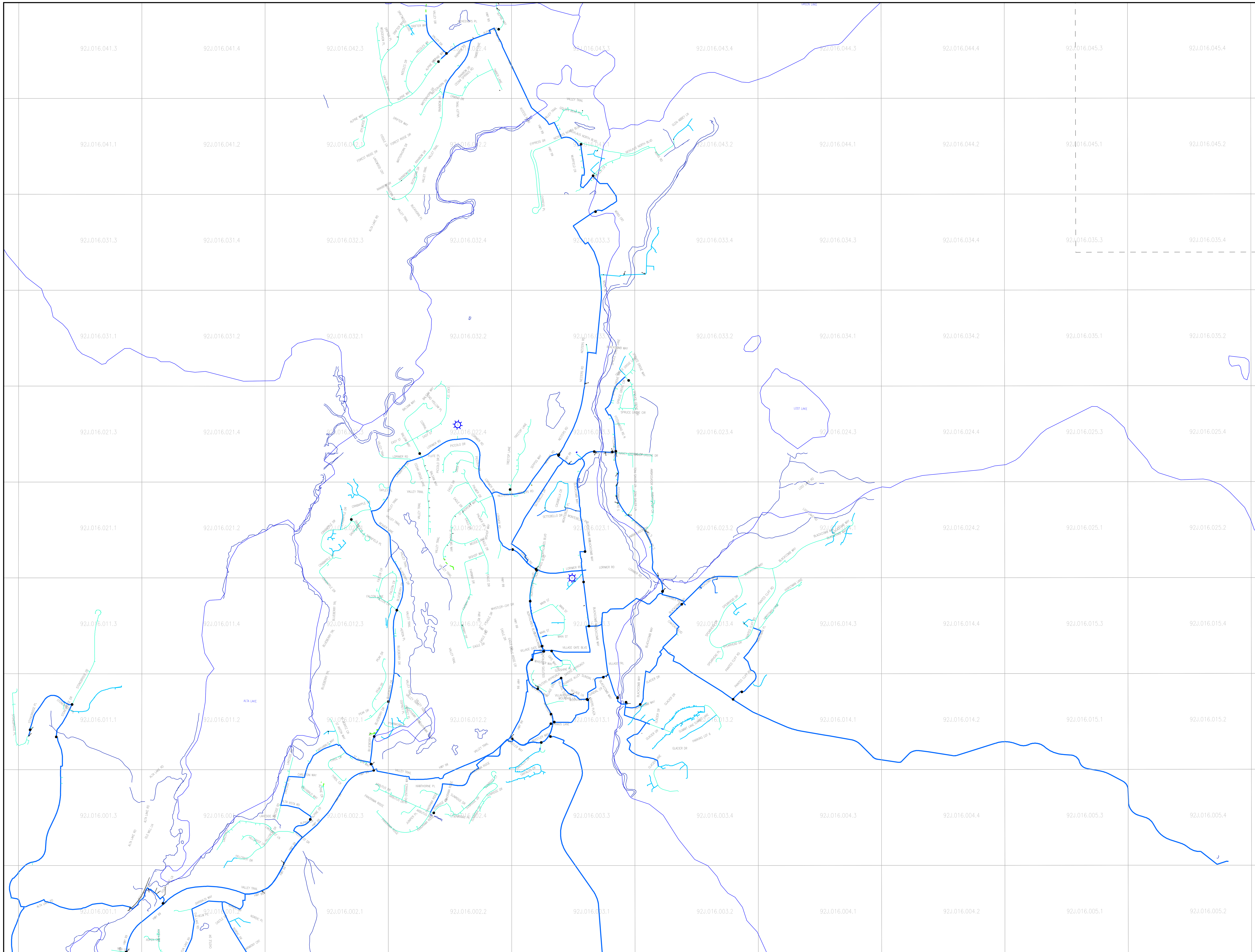
PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE - 60mm AND SMALLER
DISTRIBUTION PRESSURE - 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

| | | |
|---|---|---|
| 92J.015.3 | 92J.015.4 | 92J.016.3 |
| 92J.015.1 | 92J.015.2 | 92J.016.1 |
| 92J.005.3 | 92J.005.4 | 92J.006.3 |




Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

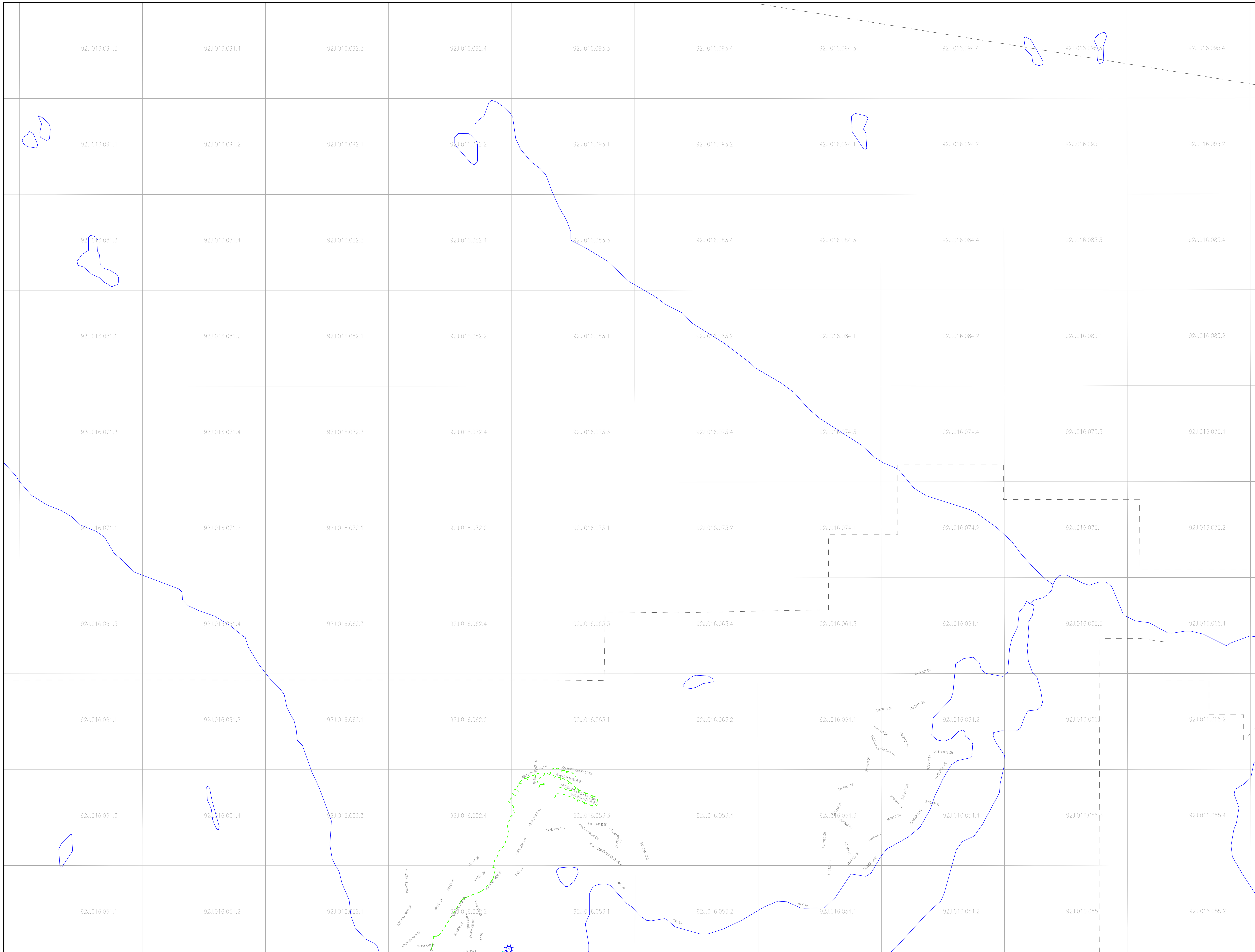
PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

| | | |
|---|---|---|
| 92J.015.4 | 92J.016.3 | 92J.016.4 |
| 92J.015.2 | 92J.016.1 | 92J.016.2 |
| 92J.005.4 | 92J.006.3 | 92J.006.4 |



Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

| | | |
|---|---|---|
| 92J.025.2 | 92J.026.1 | 92J.026.2 |
| 92J.015.4 | 92J.016.3 | 92J.016.4 |
| 92J.015.2 | 92J.016.1 | 92J.016.2 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**WORKING CAPITAL REQUIREMENTS**

| Line No. | Particulars | Reference | Actual 2011 | Adjust to Normal | Normalized 2011 | Actual 2010 | Adjust to Normal | Normalized 2010 |
|---|---|---|---|---|---|---|---|---|
| 1 | Cash Working Capital Requirements | 9.1.0 | $ 53,900 | $ (3,184) | $ 50,715 | $ 60,471 | $ 42 | $ 60,514 |
| | Inventory: | | | | | | | |
| 2 | Material and Supplies | 9.2.0 | - | | - | - | | - |
| 3 | Gas in Storage | 9.2.0 | 817,605 | | 817,605 | 623,110 | | 623,110 |
| 4 | Customer Deposits | 9.2.0 | - | | - | - | | - |
| 5 | Refundable Contributions | 9.2.0 | (12,025) | | (12,025) | (12,879) | | (12,879) |
| 6 | Withholdings from employees | 9.2.0 | (46,395) | | (46,395) | (53,564) | | (53,564) |
| 7 | Sub-Total | | $ 759,185 | $ - | $ 759,185 | $ 556,667 | $ - | $ 556,667 |
| | Deferred Expenses, Mid-Year: | 1.8.0 | | | | | | |
| 8 | Interest Rate Differential | | (364,204) | | (364,204) | (230,749) | | (230,749) |
| 9 | Gas Cost Reconciliation Account (GCRA) | | 11,492,149 | | 11,492,149 | 11,483,841 | | 11,483,841 |
| 10 | Property Tax Differential | | (4,551) | | (4,551) | 192 | | 192 |
| 11 | Cost of Gas - Rate Rider | | (11,826,576) | | (11,826,576) | (12,483,199) | | (12,483,199) |
| 12 | Sales Margin Differential | | 464,412 | | 464,412 | 558,212 | | 558,212 |
| 13 | 2009 Revenue Requirements Application | | 947 | | 947 | (30,800) | | (30,800) |
| 14 | 2010-2011 Revenue Requirements Application | | 280,613 | | 280,613 | 163,692 | | 163,692 |
| 15 | 2012 Revenue Requirement Application | | 4,360 | | 4,360 | | | |
| 16 | Deferred ROE Variance (2005-2009) | | (128,469) | | (128,469) | (281,419) | | (281,419) |
| 17 | IFRS Implementation Costs | | 8,967 | | 8,967 | 6,576 | | 6,576 |
| 18 | Capital Contribution to TGVI | | 16,522,980 | | 16,522,980 | 16,863,660 | | 16,863,660 |
| 19 | 2010 Olympic Games Security Costs | | 8,797 | | 8,797 | 8,519 | | 8,519 |
| 20 | 2009 ROE and Capital Structure Application | | 5,606 | | 5,606 | 6,592 | | 6,592 |
| 21 | CCE CPCN Application | | 2,472 | | 2,472 | 2,502 | | 2,502 |
| 22 | Appliance Conversion Planning Costs | | 677,370 | | 677,370 | 712,455 | | 712,455 |
| 23 | Direct Customer Appliance Conversion Costs | | 7,418,551 | | 7,418,551 | 8,352,084 | | 8,352,084 |
| 24 | US GAAP Conversion Costs | | 933 | | 933 | 119,950 | | 119,950 |
| 25 | Revenue Stabilization Adjustment Mechanism (RSAM) | | 281,199 | | 281,199 | 75,405 | | 75,405 |
| 26 | RSAM/MCRA/CCRA/Gas in Storage Interest | | (433) | | (433) | 67 | | 67 |
| 27 | Midstream Cost Reconciliation Account (MCRA) | | 37,445 | | 37,445 | 19,575 | | 19,575 |
| 28 | Commodity Cost Reconciliation Account (CCRA) | | (83,808) | | (83,808) | (29,042) | | (29,042) |
| 29 | Natural Gas Pipeline Development Costs | | 1,745,673 | | 1,745,673 | 1,839,973 | | 1,839,973 |
| 30 | Decommissioning of Propane Assets | | 4,296,023 | | 4,296,023 | 2,204,245 | | 2,204,245 |
| 31 | Capital Gain on Sale of Propane Land | | 39,960 | | 39,960 | 13,320 | | 13,320 |
| 32 | Property Tax - Propane Plant | | 72,775 | | 72,775 | 26,631 | | 26,631 |
| 33 | Income Tax Variance | | (887) | | (887) | (894) | | (894) |
| 34 | IFRS Transitional Adjustments | | (57,993) | | (57,993) | (29,035) | | (29,035) |
| 35 | Gains and Losses on Asset Disposition | | 188,098 | | 188,098 | 66,063 | | 66,063 |
| 36 | Deferred Removal Costs | | 6,481 | | 6,481 | 1,732 | | 1,732 |
| 37 | Sub-Total | | $ 31,088,890 | $ - | $ 31,088,890 | $ 29,440,148 | $ - | $ 29,440,148 |
| 38 | Future Income Taxes: | | | | | | | |
| 39 | Future Income Taxes Regulatory Asset | 10.1.3 | 2,108,375 | | 2,108,375 | 1,799,835 | | 1,799,835 |
| 40 | Future Income Taxes Liability | 10.1.3 | (2,108,375) | | (2,108,375) | (1,799,835) | | (1,799,835) |
| 41 | Sub-Total | | $ - | $ - | $ - | $ - | $ - | $ - |
| 42 | TOTAL WORKING CAPITAL REQUIREMENTS | | $ 31,901,975 | $ (3,184) | $ 31,898,790 | $ 30,057,286 | $ 42 | $ 30,057,329 |

**ANNUAL REPORT - 2011**

**CASH WORKING CAPITAL REQUIREMENTS**

| Line No. | Particulars | Reference | Days | Expenses | Working Capital |
|---|---|---|---|---|---|
| | CASH WORKING CAPITAL, RECORDED | | | | |
| 1 | Revenue Lag Days | | 38.7 | | |
| 2 | Expenses Lead Days | | 36.7 | | |
| 3 | Net Lead/(Lag) Days | | 2.0 | $9,966,039 | $53,900 |
| | CASH WORKING CAPITAL, NORMALIZED | | | | |
| 4 | Revenue Lag Days | | 38.7 | | |
| 5 | Expenses Lead Days | | 36.8 | | |
| 6 | Net Lead/(Lag) Days | | 1.9 | $9,847,440 | $50,715 |

| Line No. | Particulars | Reference | Revenue | Lag Days Service to Collection | Dollar Days |
|---|---|---|---|---|---|
| | REVENUE, RECORDED | | | | |
| 7 | Residential and Commercial | 4.1.0 | $12,175,955 | 38.7 | $471,209,459 |
| | Other Revenues | | | | |
| 8 | Penalty Revenue | 4.2.0 | 820 | 38.9 | 31,898 |
| 9 | Connection Charge Revenue | 4.2.0 | 1,855 | 38.9 | 72,160 |
| 10 | LPC Revenue | 4.2.0 | 19,580 | 38.9 | 761,644 |
| 11 | Miscellaneous | 4.2.0 | (2,080) | 38.9 | (80,912) |
| 12 | Total Revenue | | $12,196,130 | 38.7 | $471,994,248 |

| Line No. | Particulars | Reference | Revenue | Lag Days Service to Collection | Dollar Days |
|---|---|---|---|---|---|
| | REVENUE, NORMALIZED | | | | |
| 13 | Residential and Commercial | 10.0.0 | $11,751,321 | 38.7 | $454,776,119 |
| | Other Revenues | | | | |
| 14 | Penalty Revenue | 4.2.0 | 820 | 38.9 | 31,898 |
| 15 | Connection Charge Revenue | 4.2.0 | 1,855 | 38.9 | 72,160 |
| 16 | LPC Revenue | 4.2.0 | 19,580 | 38.9 | 761,644 |
| 17 | Miscellaneous | 4.2.0 | (2,080) | 38.9 | (80,912) |
| 18 | Total Revenue | | $11,771,495 | 38.7 | $455,560,909 |

| Line No. | Particulars | Reference | Expense | Lead Days Expense to Payment | Dollar Days |
|---|---|---|---|---|---|
| | EXPENSES, RECORDED | | | | |
| 19 | Cost of Gas | 4.0.0 | $4,156,093 | 40.2 | $167,074,939 |
| 20 | O&M Expenses | 5.0.0 | 681,702 | 35.8 | 24,404,949 |
| 21 | Property Taxes | | 278,400 | 2.6 | 723,840 |
| 22 | FEVI Transportation Costs | | 2,386,334 | 40.2 | 95,930,627 |
| 23 | HST | | 1,173,369 | 39.8 | 46,700,079 |
| 24 | Carbon Tax | | 809,166 | 29.5 | 23,870,404 |
| 25 | Income Tax | 10.1.0 | 480,974 | 15.2 | 7,310,805 |
| 26 | Total Expenses | | $9,966,039 | 36.7 | $366,015,643 |

| Line No. | Particulars | Reference | Expense | Lead Days Expense to Payment | Dollar Days |
|---|---|---|---|---|---|
| | EXPENSES, NORMALIZED | | | | |
| 27 | Cost of Gas | 10.0.0 | $4,091,107 | 40.2 | $164,462,515 |
| 28 | O&M Expenses | 5.0.0 | 681,702 | 35.8 | 24,404,949 |
| 29 | Property Taxes | | 278,400 | 2.6 | 723,840 |
| 30 | FEVI Transportation Costs | | 2,386,334 | 40.2 | 95,930,627 |
| 31 | HST | | 1,173,369 | 39.8 | 46,700,079 |
| 32 | Carbon Tax | | 809,166 | 29.5 | 23,870,404 |
| 33 | Income Tax | 10.1.0 | 427,362 | 15.2 | 6,495,895 |
| 34 | Total Expenses | | $9,847,440 | 36.8 | $362,588,310 |

**FORTISBC ENERGY (WHISTLER) INC.** **9.2.0**
**ANNUAL REPORT - 2011**
**WORKING CAPITAL REQUIREMENTS - 13 MONTH AVERAGE**

| Line No. | Particulars | 2011 Year End Balance | 2011 13 Month Average | 2010 Year End Balance | 2010 13 Month Average |
|---|---|---|---|---|---|
| 1 | Material & Supplies | $ - | $ - | $ - | $ - |
| 2 | Gas in Storage | $ 654,048 | $ 817,605 | $ 957,796 | $ 623,110 |
| 3 | Refundable Contributions | $ (10,658) | $ (12,025) | $ (12,879) | $ (12,879) |
| 4 | Withholdings from Employees | $ (46,452) | $ (46,395) | $ (45,969) | $ (53,564) |

# FORTISBC ENERGY (WHISTLER) INC.
## ANNUAL REPORT - 2011
## EARNED RETURN



| Line No. | Particulars | Reference | Actual 2011 | Adjustment to Normal | Normalized 2011 | Actual 2010 | Adjustment to Normal | Normalized 2010 |
|---|---|---|---|---|---|---|---|---|
| 1 | Gas Sales (GJ) | 4.1.0 | 736,844 | (16,091) | 720,753 | 753,195 | 12,288 | 765,483 |
| 2 | Gas Revenue at Existing Rates* | 4.1.0 | $ 12,175,955 | $ (424,634) | $ 11,751,321 | $ 13,586,846 | $ 360,608 | $ 13,947,454 |
| 3 | RSAM Revenue* | | 354,803 | 157,335 | 512,138 | 210,921 | (139,031) | 71,890 |
| 4 | Cost of Gas | 4.0.0 | 4,156,093 | (64,986) | 4,091,107 | 4,985,961 | 179,157 | 5,165,118 |
| 5 | GROSS MARGIN REVENUE | | $ 8,374,665 | $ (202,313) | $ 8,172,352 | $ 8,811,806 | $ 42,420 | $ 8,854,226 |
| 6 | Other Revenue | 4.2.0 | 20,175 | | 20,175 | 35,898 | | 35,898 |
| 7 | TOTAL REVENUE | | $ 8,394,840 | $ (202,313) | $ 8,192,527 | $ 8,847,704 | $ 42,420 | $ 8,890,124 |
| 8 | Operating Expenses | 5.0.0 | $ 681,702 | | $ 681,702 | $ 653,832 | | $ 653,832 |
| 9 | Transportation Costs | 9.1.0 | 2,386,334 | | 2,386,334 | 2,430,206 | | 2,430,206 |
| 10 | Municipal and Other Taxes | 1.7.0 | 278,400 | | 278,400 | 284,688 | | 284,688 |
| 11 | Depreciation Expense | 3.1.0 | 353,137 | | 353,137 | 353,489 | | 353,489 |
| 12 | Amortization of CIAC | 2.5.0 | (4,909) | | (4,909) | (4,764) | | (4,764) |
| 13 | Removal Costs | 5.0.0 | 4,596 | | 4,596 | 4,500 | | 4,500 |
| 14 | Amortization of Deferreds | 1.8.0 | 939,880 | | 939,880 | 1,509,335 | | 1,509,335 |
| 15 | TOTAL EXPENSES | | $ 4,639,140 | $ - | $ 4,628,040 | $ 5,231,286 | $ - | $ 5,231,286 |
| 16 | Utility Earned Return from Operations | | $ 3,755,700 | $ (202,313) | $ 3,553,387 | $ 3,616,418 | $ 42,420 | $ 3,658,838 |
| 17 | Equity Portion of AFUDC | | | | - | | | |
| 18 | Utility Earned Return before Taxes | | $ 3,755,700 | | $ 3,553,387 | $ 3,616,418 | | $ 3,658,838 |
| 19 | Total Taxes Payable | 10.1.0 | 480,974 | (53,613) | 427,361 | 658,998 | 12,090 | 671,088 |
| 20 | EARNED RETURN | | $ 3,274,726 | $ (148,700) | $ 3,126,026 | $ 2,957,420 | $ 30,330 | $ 2,987,750 |
| 21 | Calculated Earned Return | 12.0.0 | $ 3,274,726 | | $ 3,126,026 | $ 2,957,420 | | $ 2,987,750 |
| 22 | UTILITY RATE BASE | 11.0.0 | $ 45,259,235 | $ (3,184) | $ 45,256,051 | $ 45,400,380 | $ 42 | $ 45,400,422 |
| 23 | Return on Rate Base % | | 7.24% | | 6.91% | 6.51% | | 6.58% |

* 2010 comparatives have been restated.

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**INCOME TAXES**



| Line No. | Particulars | Reference | Actual 2011 | Adjustment to Normal | Normalized 2011 | Actual 2010 | Adjustment to Normal | Normalized 2010 |
|---|---|---|---|---|---|---|---|---|
| 1 | Utility Earned Return after Taxes | 12.0.0 | $ 3,274,726 | $ (148,700) | $ 3,126,026 | $ 2,957,420 | $ 30,330 | $ 2,987,750 |
| 2 | Less: Financing Expenses | 12.0.0 | (1,390,510) | | (1,390,510) | (1,232,012) | | (1,232,012) |
| 3 | Accounting Income after Taxes | 12.0.0 | 1,884,216 | (148,700) | 1,735,516 | 1,725,410 | 30,330 | 1,755,740 |
| | Add: | | | | | | | |
| 4 | Depreciation | 3.1.0 / 2.5.0 | 348,228 | | 348,228 | 348,725 | | 348,725 |
| 5 | Amortization of Deferreds | 1.8.0 | 939,880 | | 939,880 | 1,509,335 | | 1,509,335 |
| 6 | 50% Meals & Entertainment | | 1,210 | | 1,210 | 1,911 | | 1,911 |
| 7 | Gain/Loss on Asset Sale | | - | | - | 58 | | 58 |
| 8 | Unpaid Renumeration | | 4,572 | | 4,572 | 4,413 | | 4,413 |
| 9 | Total Additions | | 1,293,890 | | 1,293,890 | 1,864,442 | | 1,864,442 |
| | Deduct: | | | | | | | |
| 10 | Capital Cost Allowance | 10.1.1 | 624,165 | | 624,165 | 627,179 | | 627,179 |
| 11 | Admin & General Overhead Capitalized | | 78,138 | | 78,138 | 81,679 | | 81,679 |
| 12 | Cumulative Eligible Capital | | 1,141,779 | | 1,141,779 | 1,227,720 | | 1,227,720 |
| 13 | Total Deductions | | 1,844,082 | | 1,844,082 | 1,936,578 | | 1,936,578 |
| 14 | Taxable Income after Tax | | 1,334,023 | (148,700) | 1,185,323 | 1,653,274 | 30,330 | 1,683,604 |
| 15 | Tax Gross Up | | 73.50% | 73.50% | 73.50% | 71.50% | 71.50% | 71.50% |
| 16 | TAXABLE INCOME | | 1,814,998 | (202,313) | 1,612,685 | 2,312,272 | 42,420 | 2,354,692 |
| | Income Tax Calculation | | | | | | | |
| 17 | Federal Tax | 26.00% | 471,899 | (52,601) | 419,298 | 647,436 | 11,878 | 659,314 |
| 18 | Less: Tax Abatement | 10.00% | (181,500) | 20,231 | (161,269) | (231,227) | (4,242) | (235,469) |
| 19 | Net Federal Tax | | 290,399 | (32,370) | 258,030 | 416,209 | 7,636 | 423,845 |
| 20 | Federal Surcharge | 0.00% | - | - | - | - | - | - |
| 21 | Provincial Tax | 10.50% | 190,575 | (21,243) | 169,332 | 242,789 | 4,454 | 247,243 |
| 22 | Income Tax Expense | 26.50% | 480,974 | (53,613) | 427,362 | 658,998 | 12,090 | 671,087 |
| 23 | Less Federal Surcharge offset by LCT | 0.00% | | | | | | |
| 24 | Less Tax Recovery from Loss Carryback | | - | - | - | - | - | - |
| 25 | Net Income Tax Expense | 26.50% | 480,974 | (53,613) | 427,362 | 658,998 | 12,090 | 671,087 |
| 26 | Previous Year Adjustments | | - | | - | - | | - |
| 27 | Total Income Tax Expense | | $ 480,974 | $ (53,613) | $ 427,362 | $ 658,998 | $ 12,090 | $ 671,087 |

### Year Ended December 31, 2011

| Line | Description | Class | Rate | (1) 1-Jan-2011 Balance | (2) Opening Adjustments | (3) Cost of Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) 1/2 of (3)-(4)+(5) | (7) Reduced UCC | (8) CCA | (9) 31-Dec-2011 Ending |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $ 8,858,532 | $ - | $ - | $ - | $ - | $ - | $ 8,858,532 | $ 354,341 | $ 8,504,191 |
| 2 | Building - post March 19, 2007 | 1.3 | 6% | 16,150 | - | 2,176 | - | - | 1,088 | 17,238 | 1,034 | 17,292 |
| 3 | Utility Plant - pre 88 | 2 | 6% | 282,877 | - | - | - | - | - | 282,877 | 16,973 | 265,904 |
| 4 | F&F/Commun Equip - post 76 | 8 | 20% | 44,281 | - | 22,300 | - | - | 11,150 | 55,431 | 11,086 | 55,495 |
| 5 | Vehicles/Comp Equip/Tools | 10 | 30% | 58,248 | - | - | - | - | - | 58,248 | 17,475 | 40,773 |
| 6 | Computer Software | 12 | 100% | - | - | - | - | - | - | - | - | - |
| 7 | Leasehold Improvements | 13 | manual | - | - | - | - | - | - | - | - | - |
| 8 | Franchises | 14 | 5% | 340 | - | - | - | - | - | 340 | 17 | 323 |
| 9 | Heavy Work Improvement | 38 | 30% | 7 | - | - | - | - | - | 7 | 2 | 5 |
| 10 | Computer Equip - post March 18, 2007 | 50 | 55% | - | - | - | - | - | - | - | - | - |
| 11 | Natural Gas Distribution | 51 | 6% | 3,463,721 | - | 513,806 | - | - | 256,903 | 3,720,624 | 223,237 | 3,754,290 |
| 12 | Computer Equip - post January 27, 2009 and before February 2011 | 52 | 100% | - | - | - | - | - | - | - | - | - |
| 13 | | | | $ 12,724,156 | $ - | $ 538,282 | $ - | $ - | $ 269,141 | $ 12,993,297 | $ 624,165 | $ 12,638,273 |

### Year Ended December 31, 2010

| Line | Description | Class | Rate | (1) 1-Jan-2010 Balance | (2) Opening Adjustments | (3) Cost of Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) 1/2 of (3)-(4)+(5) | (7) Reduced UCC | (8) CCA | (9) 31-Dec-2010 Ending |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | Building and Utility - post 87 | 1 | 4% | $ 9,227,638 | $ - | $ - | $ - | $ - | $ - | $ 9,227,638 | $ 369,106 | $ 8,858,532 |
| 15 | Building - post March 19, 2007 | 1.3 | 6% | - | - | 16,649 | - | - | 8,325 | 8,325 | 499 | 16,150 |
| 16 | Utility Plant - pre 88 | 2 | 6% | 300,933 | - | - | - | - | - | 300,933 | 18,056 | 282,877 |
| 17 | Building - post 87 | 3 | 5% | - | - | - | - | - | - | - | - | - |
| 18 | Buildings Portable | 6 | 10% | - | - | - | - | - | - | - | - | - |
| 19 | F&F/Commun Equip - post 76 | 8 | 20% | 48,963 | - | 5,678 | - | - | 2,839 | 51,802 | 10,360 | 44,281 |
| 20 | Commun Equip - pre 77 | 9 | 25% | - | - | - | - | - | - | - | - | - |
| 21 | Vehicles/Comp Equip/Tools | 10 | 30% | 86,108 | - | - | 2,896 | - | - | 83,212 | 24,964 | 58,248 |
| 22 | Computer Software | 12 | 100% | - | - | - | - | - | - | - | - | - |
| 23 | Leasehold Improvements | 13 | 1/5 | - | - | - | - | - | - | - | - | - |
| 24 | Franchises | 14 | 5% | 358 | - | - | - | - | - | 358 | 18 | 340 |
| 25 | Earth Moving Equipment | 22 | 50% | - | - | - | - | - | - | - | - | - |
| 26 | Heavy Work Improvement | 38 | 30% | 10 | - | - | - | - | - | 10 | 3 | 7 |
| 27 | Natural Gas Distribution | 51 | 6% | 3,116,041 | - | 551,178 | - | - | 275,589 | 3,391,630 | 203,498 | 3,463,721 |
| 28 | | | | $ 12,780,051 | $ - | $ 573,505 | $ 2,896 | $ - | $ 286,753 | $ 13,063,907 | $ 626,504 | $ 12,724,156 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**UCC CONTINUITY - INCOME TAX PURPOSES (Shareholder)**

**Year Ended December 31, 2011**

| Line | Description | Class | Rate | (1) 1-Jan-2011 Balance | (2) Opening Adjustments | (3) Cost of Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) 1/2 of (3)-(4)+(5) | (7) Reduced UCC | (8) CCA | (9) 31-Dec-2011 Ending |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Building and Utility - post 87 | 1 | 4% | $ 8,858,532 | $ - | $ - | $ - | $ - | $ - | $ 8,858,532 | $ 354,341 | $ 8,504,191 |
| 2 | Building - post March 19, 2007 | 1.3 | 6% | 16,150 | - | 26,506 | - | - | 13,253 | 29,403 | 1,764 | 40,892 |
| 3 | Utility Plant - pre 88 | 2 | 6% | 282,877 | - | - | - | - | - | 282,877 | 16,973 | 265,904 |
| 4 | F&F/Commun Equip - post 76 | 8 | 20% | 44,281 | - | 31,180 | - | - | 15,590 | 59,871 | 11,974 | 63,487 |
| 5 | Vehicles/Comp Equip/Tools | 10 | 30% | 58,248 | - | - | - | - | - | 58,248 | 17,474 | 40,774 |
| 6 | Computer Software | 12 | 100% | - | - | 126,781 | - | - | 63,391 | 63,391 | 63,391 | 63,390 |
| 7 | Leasehold Improvements | 13 | manual | - | - | 12,058 | - | - | 6,029 | 6,029 | 402 | 11,656 |
| 8 | Franchises | 14 | 5% | 340 | - | - | - | - | - | 340 | 17 | 323 |
| 9 | Heavy Work Improvement | 38 | 30% | 7 | - | - | - | - | - | 7 | 2 | 5 |
| 10 | Computer Equip - post March 18, 2007 | 50 | 55% | - | - | 12,637 | - | - | 6,319 | 6,319 | 3,475 | 9,162 |
| 11 | Natural Gas Distribution | 51 | 6% | 3,463,721 | - | 513,806 | - | - | 256,903 | 3,720,624 | 223,237 | 3,754,290 |
| 12 | Computer Equip - post January 27, 2009 and before February 2011 | 52 | 100% | - | - | 4,239 | - | - | - | 4,239 | 4,239 | - |
| 13 | | | | $ 12,724,156 | $ - | $ 727,207 | $ - | $ - | $ 361,484 | $ 13,089,879 | $ 697,289 | $ 12,754,074 |

**Year Ended December 31, 2010 (trued-up to 2010 T2 Corporation Tax Returns)**

| Line | Description | Class | Rate | (1) 1-Jan-2010 Balance | (2) Opening Adjustments | (3) Cost of Additions | (4) Proceeds of Disposition | (5) Adjustments | (6) 1/2 of (3)-(4)+(5) | (7) Reduced UCC | (8) CCA | (9) 31-Dec-2010 Ending |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | Building and Utility - post 87 | 1 | 4% | $ 9,227,638 | $ - | $ - | $ - | $ - | $ - | $ 9,227,638 | $ 369,106 | $ 8,858,532 |
| 15 | Building - post March 19, 2007 | 1.3 | 6% | - | - | 16,649 | - | - | 8,325 | 8,325 | 499 | 16,150 |
| 16 | Utility Plant - pre 88 | 2 | 6% | 300,933 | - | - | - | - | - | 300,933 | 18,056 | 282,877 |
| 17 | Building - post 87 | 3 | 5% | - | - | - | - | - | - | - | - | - |
| 18 | Buildings Portable | 6 | 10% | - | - | - | - | - | - | - | - | - |
| 19 | F&F/Commun Equip - post 76 | 8 | 20% | 48,963 | - | 5,678 | - | - | 2,839 | 51,802 | 10,360 | 44,281 |
| 20 | Commun Equip - pre 77 | 9 | 25% | - | - | - | - | - | - | - | - | - |
| 21 | Vehicles/Comp Equip/Tools | 10 | 30% | 86,108 | - | - | 2,896 | - | - | 83,212 | 24,964 | 58,248 |
| 22 | Computer Software | 12 | 100% | - | - | - | - | - | - | - | - | - |
| 23 | Leasehold Improvements | 13 | 1/5 | - | - | - | - | - | - | - | - | - |
| 24 | Franchises | 14 | 5% | 358 | - | - | - | - | - | 358 | 18 | 340 |
| 25 | Earth Moving Equipment | 22 | 50% | - | - | - | - | - | - | - | - | - |
| 26 | Heavy Work Improvement | 38 | 30% | 10 | - | - | - | - | - | 10 | 3 | 7 |
| 27 | Natural Gas Distribution | 51 | 6% | 3,116,041 | - | 551,178 | - | - | 275,589 | 3,391,630 | 203,498 | 3,463,721 |
| 28 | | | | $ 12,780,051 | $ - | $ 573,505 | $ 2,896 | $ - | $ 286,753 | $ 13,063,907 | $ 626,504 | $ 12,724,156 |

**FUTURE INCOME TAXES (FIT)**

| Line No. | Description | 2011 |
|---|---|---|
| | (1) | (2) |
| 1 | Property, Plant & Equipment | |
| 2 | Net Book Value | $ (13,612,988) |
| 3 | Less: Undepreciated Capital Cost | (13,687,540) |
| 4 | | 74,552 |
| 5 | Weighted Average Future Tax Rate | 25% |
| 6 | | 18,638 |
| 7 | | |
| 8 | Total FIT Liability - After tax (PP&E) | 18,638 |
| 9 | Total FIT Liability - After tax (Non-PP&E) | (1,732,492) |
| 10 | Total FIT Liability - After tax | (1,713,854) |
| 11 | | |
| 12 | Tax Gross Up | (571,285) |
| 13 | | |
| 14 | FIT Liability/Asset - End of Year | (2,285,139) |
| 15 | | |
| 16 | FIT Liability/Asset - Opening Balance | (1,931,611) |
| 17 | | |
| 18 | FIT Liability/Asset - Mid Year | $ (2,108,375) |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**UTILITY RATE BASE**

| Line No. | Particulars | Reference | Actual 2011 | Adjust to Normal | Normalized 2011 | Actual 2010 | Adjust to Normal | Normalized 2010 |
|---|---|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | | | |
| 1 | Beginning of Year | 2.1.0 | $ 16,593,964 | | $ 16,593,964 | $ 16,158,758 | | $ 16,158,758 |
| 2 | End of Year | 2.1.0 | 17,024,567 | | 17,024,567 | 16,593,964 | | 16,593,964 |
| 3 | Average Balance - Mid-Year | | $ 16,809,266 | | $ 16,809,266 | $ 16,376,361 | | $ 16,376,361 |
| | ACCUMULATED DEPRECIATION | | | | | | | |
| 4 | Beginning of Year | 3.1.0 | $ (3,167,754) | | $ (3,167,754) | $ 1,402,333 | | $ 1,402,333 |
| 5 | End of Year | 3.1.0 | (3,436,358) | | (3,436,358) | (3,167,754) | | (3,167,754) |
| 6 | Average Balance - Mid-Year | | $ (3,302,056) | | $ (3,302,056) | $ (882,711) | | $ (882,711) |
| | CIAC | | | | | | | |
| 7 | Beginning of Year | 2.5.0 | $ (186,195) | | $ (186,195) | $ (169,324) | | $ (169,324) |
| 8 | End of Year | 2.5.0 | (201,790) | | (201,790) | (186,195) | | (186,195) |
| 9 | Average Balance - Mid-Year | | $ (193,992) | | $ (193,992) | $ (177,759) | | $ (177,759) |
| | ACCUMULATED AMORTIZATION - CIAC | | | | | | | |
| 10 | Beginning of Year | 2.5.0 | $ 11,677 | | $ 11,677 | $ 6,913 | | $ 6,913 |
| 11 | End of Year | 2.5.0 | 16,586 | | 16,586 | 11,677 | | 11,677 |
| 12 | Average Balance - Mid-Year | | $ 14,132 | | $ 14,132 | $ 9,295 | | $ 9,295 |
| 13 | NET MID-YEAR PLANT IN SERVICE | | $ 13,327,350 | $ - | $ 13,327,350 | $ 15,325,186 | $ - | $ 15,325,186 |
| 14 | Adjustment to 13-Month Average | | - | | - | - | | - |
| 15 | Work in Progress - No AFUDC | | 29,910 | | 29,910 | 17,908 | | 17,908 |
| 16 | Working Capital Requirements | 9.0.0 | 31,901,975 | (3,184) | 31,898,791 | 30,057,286 | 42 | 30,057,328 |
| 17 | UTILITY RATE BASE, MID-YEAR | | $ 45,259,235 | $ (3,184) | $ 45,256,051 | $ 45,400,380 | $ 42 | $ 45,400,422 |

**FORTISBC ENERGY (WHISTLER) INC.** **12.0.0**
**ANNUAL REPORT - 2011**
**CAPITAL STRUCTURE AND COST OF CAPITAL**

## 2011

**Actual**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 1 | Short Term Debt | | $ 7,155,541 | 15.81% | 5.15% | 0.81% | $368,510 | $368,510 |
| 2 | Long Term Debt | | 20,000,000 | 44.19% | 5.11% | 2.26% | $1,022,000 | 1,022,000 |
| 3 | Common Equity | | 18,103,694 | 40.00% | 10.41% | 4.16% | 1,884,216 | |
| 4 | Mid Year Rate Base | 11.0.0 | $ 45,259,235 | 100.00% | | 7.24% | $3,274,726 | $1,390,510 |

**Normalized**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 5 | Short Term Debt | | $ 7,153,631 | 15.81% | 5.15% | 0.81% | $368,510 | $368,510 |
| 6 | Long Term Debt | | 20,000,000 | 44.19% | 5.11% | 2.26% | $1,022,000 | $1,022,000 |
| 7 | Common Equity | | 18,102,420 | 40.00% | 9.59% | 3.83% | 1,735,516 | |
| 8 | Mid Year Rate Base | 11.0.0 | $45,256,051 | 100.00% | | 6.91% | $3,126,026 | $1,390,510 |

## 2010

**Actual**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 9 | Short Term Debt | | $ 7,240,228 | 15.95% | 2.90% | 0.46% | $210,012 | $210,012 |
| 10 | Long Term Debt | | 20,000,000 | 44.05% | 5.11% | 2.25% | 1,022,000 | 1,022,000 |
| 11 | Common Equity | | 18,160,152 | 40.00% | 9.50% | 3.80% | 1,725,408 | |
| 12 | Mid Year Rate Base | 11.0.0 | $ 45,400,380 | 100.00% | | 6.51% | $2,957,420 | $1,232,012 |

**Normalized**

| Line No. | Particulars | Reference | Capitalization Amount | Capitalization % | Annual Rate % | Cost Component % | Earned Return | Annual Debt Cost |
|---|---|---|---|---|---|---|---|---|
| 13 | Short Term Debt | | $ 7,240,253 | 15.95% | 2.90% | 0.46% | $210,012 | $210,012 |
| 14 | Long Term Debt | | 20,000,000 | 44.05% | 5.11% | 2.25% | 1,022,000 | 1,022,000 |
| 15 | Common Equity | | 18,160,169 | 40.00% | 9.67% | 3.87% | 1,755,738 | |
| 16 | Mid Year Rate Base | 11.0.0 | $ 45,400,422 | 100.00% | | 6.58% | $2,987,750 | $1,232,012 |

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT - 2011**
**EXECUTIVE COMPENSATION**

With a single management and support team for the entire FortisBC Energy Inc. group of companies, services are delivered on a shared basis. Utilizing a framework similar to that used by FortisBC Holdings Inc. to allocate corporate center management fees to FortisBC Energy Inc., the allocated shared services cost to FortisBC Energy (Whistler) Inc. from FortisBC Energy Inc. was $212 thousand in 2011.

**FORTISBC ENERGY (WHISTLER) INC.**
**ANNUAL REPORT – 2011**
**NEW DIRECTIONS TO THE UTILITIES UNDER BCUC'S JURISDICTION**

## 1. Outlook 2012 Capital Projects

FEW considers material capital expenditures to be those projects with an expenditure equal or greater than 1% of rate base. No material capital projects have been identified for 2012 (identified projects exclude AFUDC).

## 2. 2011 Material Capital Projects

No material capital projects were identified in 2011 (identified projects exclude AFUDC).

## 3. Income Tax Assessments

Income tax assessments and re-assessments received in 2011 are attached.

## 4. Management Letters

The Company's auditors issued no management letters in 2011 for FortisBC Energy (Whistler) Inc.

## 5. Internal Audit

There were no internal audits specifically addressing FortisBC Energy (Whistler) Inc. matters only. Any reports that are relevant to FortisBC Energy (Whistler) Inc. are included in Tab 13 of the FEI Annual Report.

## 6. Reconciliation

The reconciliation of the Annual Report with the financial statements is on pages 1.6.0 and 1.7.1 of the Annual Report.

## 7. Regulatory Compliance

FEW's accounting system conforms to the Uniform System of Accounting with the exception of Operations & Maintenance expenses which are reported according to both a resource view and an activity view as approved by order G-146-07. This is in accordance with the Commission's financial directions.

## 8. Contributions in Aid of Construction

No refundable contributions were received in 2011 and no customers were refunded prior contributions in 2011.

## 9. Reconciliation of Regulatory Accounts to Canadian GAAP

As requested by BCUC Order G-117-11, a reconciliation of amounts reported for regulatory accounting to those amounts that would be reported under 2011 Canadian GAAP is attached.

Canada Revenue Agency | Agence du revenu du Canada

Surrey BC V3T 5E1



| | |
|---|---|
| Date of mailing | June 30, 2011 |
| Business Number | 89138 9652 RC0001 |
| Tax year-end | December 31, 2010 |

FORTISBC ENERGY (WHISTLER)
INC.
10FL-1111 GEORGIA ST W
VANCOUVER BC V6E 4M3

0004991

# CORPORATION NOTICE OF ASSESSMENT

## RESULTS

**Thank you for choosing to use our Corporation Internet Filing service.**

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

| | | |
|---|---|---|
| Result of this Assessment : | $ | 57,028.23 |
| Prior balance: | $ | 7,051.88 Cr |
| | | ================ |
| Total balance: | $ | 49,976.35 |

We will not charge additional interest on the total balance shown if you pay the full amount by July 20, 2011.

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency / Agence du revenu du Canada

FORTISBC ENERGY (WHISTLER) INC.



| | |
|---|---|
| Date of mailing | June 30, 2011 |
| Business Number | 89138 9652 RC0001 |
| Tax year-end | December 31, 2010 |

## CORPORATION NOTICE OF ASSESSMENT

### SUMMARY OF ASSESSMENT

| | $ Reported | $ Assessed |
|---|---|---|
| **Federal Tax:** | | |
| Part I | 150,522.00 | 150,522.00 |
| Part I.3 | 0.00 | 0.00 |
| Part II | 0.00 | 0.00 |
| Part III.1 | 0.00 | 0.00 |
| Part IV | 0.00 | 0.00 |
| Part IV.1 | 0.00 | 0.00 |
| Part VI | 0.00 | 0.00 |
| Part VI.1 | 0.00 | 0.00 |
| Part XIII.1 | 0.00 | 0.00 |
| Part XIV | 0.00 | 0.00 |
| **Total Federal Tax:** | | $ 150,522.00 |
| **Net Provincial and Territorial Tax/Credit:** | | |
| British Columbia | 87,805.00 | 87,805.00 |
| **Total Net Provincial and Territorial Tax/Credit:** | | $ 87,805.00 |
| Instalment(s) applied | | 182,241.00 Cr |
| Net balance: | | $ 56,086.00 |
| **Interest:** | | |
| Arrears interest | | 942.23 |
| Result of this assessment: | | $ 57,028.23 |
| Prior balance: | | $ 7,051.88 Cr |
| Total balance: | | $ 49,976.35 |

Linda Lizotte-MacPherson
Commissioner of Revenue

### EXPLANATION

We have provided a breakdown of the provincial and territorial tax and credit amounts.

**Net British Columbia tax/credit consists of the following:**

| | |
|---|---|
| British Columbia tax | $ 87,805.00 |

We have adjusted the amount of payments to agree with the amount in our records. On your return, the total amount of payments is $238,327.00 while the amount in our records is $182,241.00.

We have charged you arrears interest because you did not pay the amount owing by the due date.

For your information we have attached a statement explaining how we have calculated interest.

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide" or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information

Canada Revenue Agency | Agence du revenu du Canada

FORTISBC ENERGY (WHISTLER) INC.



| | |
|---|---|
| Date of mailing | June 30, 2011 |
| Business Number | 89138 9652 RC0001 |
| Tax year-end | December 31, 2010 |

0004992

## CORPORATION NOTICE OF ASSESSMENT

online.

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

For information visit www.cra.gc.ca or contact:

Business Enquiries: 1-800-959-5525
Surrey Tax Centre
9755 King George Boulevard
Surrey BC V3T 5E1
Fax 604-585-5772

Vancouver Tax Services Office

| Date of mailing |
| --- |
| June 30, 2011 |
| Business Number |
| 89138 9652 RC0001 |
| Tax year-end |
| December 31, 2010 |

**CORPORATION NOTICE OF ASSESSMENT**

Canada Revenue Agency | Agence du revenu du Canada

FORTISBC ENERGY (WHISTLER) INC.



| | |
|---|---|
| Date of mailing | June 30, 2011 |
| Business Number | 89138 9652 RC0001 |
| Tax year-end | December 31, 2010 |

0004993

**CORPORATION NOTICE OF ASSESSMENT**

## Payment Options

Make your payment online using the Canada Revenue Agency's My Payment option.
For more information, or to use My Payment, go to www.cra.gc.ca/mypayment.

You can also:

- Use your financial institution's Internet or telephone banking services. For more information contact your financial institution.
- Present this form and your payment to the teller at your financial institution. This service is free of charge at banks located in Canada.
- Mail this remittance voucher, along with your cheque or money order made payable to the Receiver General, to the address on the back of the voucher. Please write your 15 character Business Number on the back of your cheque or money order.

**Please use the attached voucher to pay the indicated amount owing.**

Amount paid

Canada Revenue Agency | Agence du revenu du Canada

**CORPORATION INCOME TAX**
**Amount Owing Remittance Voucher**

Business Name
FORTISBC ENERGY (WHISTLER)

Business Number
89138 9652 **RC** 0001

71 | 7

Amount owing ($)
49,976.35

**Amount paid**

RC159 E (06/04)

072009007100070089138965 2RC0001000000000004997635072009 5

⑆122O4⑈117⑆

96

Canada Revenue Agency / Agence du revenu du Canada

FORTISBC ENERGY (WHISTLER) INC.



| | |
|---|---|
| Date of mailing | June 30, 2011 |
| Business Number | 89138 9652 RC0001 |
| Tax year-end | December 31, 2010 |

**CORPORATION NOTICE OF ASSESSMENT**

We used your payment pattern to determine whether to include a return envelope with this remittance voucher.

**Teller's Stamp**

We will charge a fee for any dishonoured payment.
DO NOT staple, paper clip, tape or fold this voucher or your cheque and do not use photocopied remittance vouchers.
DO NOT mail cash.
If an envelope accompanied this voucher, please ensure the address below appears in the window of the envelope provided.

**Teller's Stamp**

CANADA REVENUE AGENCY
TECHNOLOGY CENTRE
875 HERON RD
OTTAWA ON K1A 1B1

**FORTISBC ENERGY (WHISTLER) INC.**
**Summary of Refundable Contributions - 2011**

| Line No. | Date | Description | Actual Contribution | Refunds | Balance |
|---|---|---|---|---|---|
| 1 | Mar-05 | Nita Lake Joint Venture | $ 12,879 | $ - | $ 12,879 |
| 2 | **Total** | | $ 12,879 | $ - | $ 12,879 |
| 3 | **Total contributions in 2011** | | | | **Nil** |
| 4 | **Total refunds in 2011** | | | | **Nil** |

FORTISBC ENERGY (WHISTLER) INC.
RECONCILIATION OF REGULATED ACCOUNTS TO CANADIAN GAAP FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2011

| BALANCE SHEET | Financial | Reclasses | Reg Differences | Timing Differences | Annual Report Page 1.6 | Annual Report Rate Base | Non Rate Base /Non Reg | Description |
|---|---|---|---|---|---|---|---|---|
| **ASSETS** | | | | | | | | |
| *Current Assets* | | | | | | | | |
| Accounts Receivable | $ 3,901 | $ 15 [9] | | | $ 3,916 | $ 54 | $ 3,862 | Cash working capital component broken out |
| Due from Related Parties | $ 657 | | | | $ 657 | $ - | $ 657 | Investments in subs not regulated |
| Gas Inventory | $ 654 | | | | $ 654 | $ 654 | | |
| Prepaid Expenses | $ 14 | | | | $ 14 | $ - | $ 14 | Not included in working capital calculation |
| Current portion of rate stabilization account | $ 48 | $ (48) [18] | | | $ - | | | |
| Future Income Taxes | $ 37 | $ (37) [26] | | | $ - | | | |
| Property, Plant & Equipment | $ 13,408 | $ 3,613 [10,14,15] | | $ (198) [16] | $ 16,823 | $ 16,823 | $ - | |
| Intangible Assets | $ 216 | $ (216) [14] | | | $ - | $ - | | |
| Gas Plant Under Construction | | $ 23 [15] | | $ 198 [16] | $ 221 | $ 23 | $ 198 | Customer service project not included in 2011 rate base - timing difference on in-service date |
| Rate Stabilization Account | $ 549 | $ (549) [18] | | | $ - | | | |
| Preliminary Surveys | | $ 1,699 [17] | | | $ 1,699 | $ 1,699 | | |
| Unamortized Conversion Expenses | | $ 7,885 [17] | | | $ 7,885 | $ 7,885 | | |
| Future Income Taxes | | $ 2,286 [12] | | | $ 2,286 | $ 2,286 | | |
| Deferred Charges | $ 34,682 | $ (11,828) [12,13,17,18,23,26] | $ (827) [11] | $ 145 [4,6,24,25] | $ 22,172 | $ 22,525 | $ (353) | Customer refunds, customer service O&M costs, amalgamation costs, 2012 RRA costs in non-rate base deferrals |
| **TOTAL ASSETS** | $ 54,166 | $ 2,843 | $ (827) | $ 145 | $ 56,327 | $ 51,949 | $ 4,378 | |
| | | | | | $ - | | | |
| **LIABILITIES** | | | | | | | | |
| *Current Liabilities* | | | | | | | | |
| Accounts payable and accrued liabilities | $ 469 | $ (380) [13,19] | | | $ 89 | $ (46) | $ (43) | Employee withholdings included in rate base |
| Accounts payable - Affiliated companies | | $ 28,740 [20] | $ (5) [22] | | $ 28,735 | $ - | $ (28,735) | Investments in subs not regulated |
| Income and other taxes payable | $ 307 | | $ 1 [22] | $ 18 [24,25] | $ 326 | $ - | $ (326) | Tax payable for financial purposes only |
| Due to related parties | $ 8,740 | $ (8,740) [20] | | | $ - | | | |
| Deferred credits | $ 195 | $ (195) [23] | | | $ - | | | |
| Customer deposit | $ 111 | $ (111) [21] | | | $ - | | | |
| Customer's Security Deposits | | $ 100 [21] | | | $ 100 | $ - | $ (100) | Not included in working capital calculation |
| Customer's Advances for Construction | | $ 11 [21] | | | $ 11 | $ (11) | | |
| Current Portion of Rate Stabilization Account | $ 146 | $ (146) [23] | | | $ - | | | |
| Future Income Tax | $ 12 | $ (12) [26] | | | $ - | | | |
| Allowance for Doubtful Accounts | | $ 15 [9] | | | $ 15 | | $ (15) | Not included in working capital calculation |
| Interest Payable and Accrued | | $ 1 [19] | | | $ 1 | $ - | $ (1) | Not included in working capital calculation |
| Accumulated Depreciation - Gas Plant | | $ 3,420 [10] | | | $ 3,420 | $ (3,420) | $ - | |
| Long-term advance due to parent | $ 20,000 | $ (20,000) [20] | | | $ - | | | |
| Deferred credits | $ 998 | $ 164 [12,23] | $ 4 [22] | $ 1 [3] | $ 1,167 | $ (1,167) | | |
| Future income taxes | $ 3,137 | $ (24) [12,26] | $ (827) [11] | | $ 2,286 | $ (2,286) | | |
| **EQUITY** | | | | | | | | |
| Share capital | $ 16,671 | | | | $ 16,671 | | | |
| Retained Earnings, opening difference | | | | $ (4) [5,7] | $ (4) | | | |
| Retained Earnings, current year-regulatory | $ 3,380 | | $ (123) | $ 130 | $ 3,387 | | | |
| Retained Earnings, current year-other | | | $ 123 [1,8,27] | | $ 123 | | | |
| **TOTAL LIABILITIES AND EQUITY** | $ 54,166 | $ 2,843 | $ (827) | $ 145 | $ 56,327 | $ 96,968 | $ (20,464) | |

FORTISBC ENERGY (WHISTLER) INC.
RECONCILIATION OF REGULATED ACCOUNTS TO CANADIAN GAAP FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2011 - CONT'D

| **INCOME STATEMENT** | **Financial** | **Reclasses** | **Reg Differences** | **Timing Differences** | **Annual Report Page 12.0** | |
|---|---|---|---|---|---|---|
| **REVENUE** | | | | | | |
| Natural gas and propane distribution | $ 12,557 | | $ (6) [1] | | $ 12,551 | |
| **TOTAL REVENUE** | $ 12,557 | $ - | $ (6) | $ - | $ 12,551 | |
| **EXPENSES** | | | | | | |
| Cost of natural gas and propane | $ 4,156 | | | | $ 4,156 | |
| Operation and maintenance | $ 686 | $ (5) [2] | | | $ 681 | |
| Depreciation and amortization | $ 1,288 | $ 5 [2] | | $ 1 [4] | $ 1,294 | |
| Property and other taxes | $ 228 | | | $ 50 [5] | $ 278 | |
| Wheeling | $ 2,386 | | | | $ 2,386 | |
| **TOTAL EXPENSES** | $ 8,744 | $ - | $ - | $ 51 | $ 8,795 | |
| **OPERATING (LOSS) INCOME** | $ 3,813 | $ - | $ (6) | $ (51) | $ 3,756 | |
| Financing costs | $ 1,504 | | $ 136 [27] | $ (249) [6,7] | $ 1,391 | Earned Return on Short-term + Long-term debt pg12.0.0 |
| **(LOSS) EARNINGS BEFORE INCOME TAXES** | $ 2,309 | $ - | $ (142) | $ 198 | $ 2,365 | |
| Income tax (recovery) expense | $ 432 | | $ (19) [8] | $ 68 [3,6,7] | $ 481 | |
| **NET (LOSS) INCOME** | $ 1,877 | $ - | $ (123) | $ 130 | $ 1,884 | Earned Return on Equity pg12.0.0 |
| **RETAINED EARNINGS** | | | | | | |
| Balance Beginning of Year | $ 4,803 | | | | $ 4,799 | |
| Less: Dividends on Common Shares | $ (3,300) | | | | $ (3,300) | |
| Add: Net Income | $ 1,877 | $ - | $ (123) | $ 130 | $ 1,884 | |
| Balance End of Year | $ 3,380 | | $ (123) | $ 130 | $ 3,383 | |

FORTISBC ENERGY (WHISTLER) INC.
RECONCILIATION OF REGULATED ACCOUNTS TO CANADIAN GAAP FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2011 - CONT'D

**FEW Entries**

1 To recognize AFUDC-Equity is non-regulated
2 Removal Costs reclass done for financial purposes only
3 Removal cost tax benefit - timing. Booked in Reg books in 2011, finance books in 2012
4 General plant asset retirement - timing. Booked in Reg books in 2010, financial books in in 2011
5 Adjustment to defer property tax expense on the propane plant. Booked in Reg books in 2010, financial books in 2011
6 2011 Short-term debt adjustment-timing. Booked in Reg books in 2011, financial books in 2012
7 2010 Short-term debt adjustment-timing. Booked in Reg books in 2010, financial books in 2011
8 To recognize difference in regulated income tax expense

9 Reclass allowance for doubtful account classified as liability for reg purposes and asset for financial purposes
10 Reclass accumulated depreciation classified as liability for reg purposes and asset for financial purposes
11 Non-regulated Future Income Taxes for financial purposes only
12 Reclass Future Income Taxes from deferred charges

13 Reclass customer refunds classified as accounts payable for reg purposes but deferral for finance purposes
14 Reclass Intangible assets to Gas Plant in Service for presentation purposes
15 Gas Plant Under Construction separated out for presentation purposes
16 Customer Service project timing difference - in-service Dec 11 in Finance books and Jan 12 in Reg books
17 Reclass Preliminary Surveys and Unamortized Conversion Expenses included in deferred charges in Finance books but separated out in Reg books for presentation purposes
18 Reclass Rate Stabilization amounts to deferred charges
19 Reclass interest payable for presentation purposes
20 Reclass intercompany payables for presentation purposes
21 Reclass customer deposits for presentation purposes and recognize that customer security deposits are not included in rate base
22 To record deferred interest on CCRA/MCRA/Gas in Storage allocated from FEI for reg purposes only
23 Reclass deferred credits for presentation purposes
24 Income tax on IFRS conversion cost deferral-timing. Booked in Reg books in 2011, finance books in 2012
25 To recognize timing difference in CCA tax benefit from Customer Service project
26 Reclass future income tax for presentation purposes
27 To recognize difference in regulated interest expense

8. **Historical (2002-2011) regulatory financial information by year:**
    a. Capital Structure Components: common equity, preferred equity, long and short-term debt:
        i. Rate Base: opening, closing and mid-year,
        ii. Gross rate base if different from rate base that is subject to debt and equity return,
        iii. Income statement,
        iv. Summary and full detailed description of all deferral and reserve accounts:
    b. Summary and full detailed description of all deferral and reserve accounts:
        i. Average percentage of delivery revenue covered by each account,
        ii. Average percentage of total revenue (including commodity/energy cost) covered by each amount

- See attached **electronic** documents for FEW's financial information

**9. Price to Book Value Ratios (including supporting calculations) since 2000 when the utility or its corporate parent has been acquired by another firm:**

- See section 9 of FEI's Minimum Filing Requirements

a. Interpretation of Price to Book Values Ratios

- The FBCU interprets the above Price to Book Value ratios as representative of transactions that occurred at a point in time and that there are factors other than the Price to Book Value ratios that are more relevant in determining a fair return.

- For discussion on the general relevance of Price to Book Value with respect to the Generic Cost of Capital proceeding, please see the Price to Book Value section in the expert testimony of Aaron Engen as part of FBCU's Other Filing Requirements submission.

**10. Full explanation of any significant changes in accounting policy in the last 10 years.**

- See the attachment for discussion on FEW's accounting policy changes in the last 10 years

## FortisBC Energy (Whistler) Inc.
## 10 Year Summary of Significant Changes in Accounting Policy included in Regulatory Applications (2002-2011)

**2002 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2003 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2004 – 2005 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2006 Revenue Requirements Application**

No application was filed.

**2007 Revenue Requirements Application**

A full Revenue Requirement application was not filed.

**2008 Revenue Requirements Application**

A full Revenue Requirement application was not filed.

**2009 Revenue Requirements Application**

This application included one accounting policy change:

| | | |
|---|---|---|
| Section 10 | Future Income Taxes | Pages 53 - 54 |

Currently, the CICA Handbook Section 3465 for Income Taxes contains a specific exemption for rate regulated enterprises. Beginning with the first quarter of 2009, TGW will adopt the changes resulting from paragraphs 102, 103 and 112A of CICA Handbook section 3465.

These changes do not have an impact on rate base as there is both a regulatory future income tax asset and an offsetting future income tax liability included in the rate base. Deferral accounts will continue to be maintained on a net-of-tax basis for regulatory purposes but shown on a gross basis for financial statement purposes. The recovery of income taxes for regulatory purposes remains on the taxes payable method.

**2010-2011 Revenue Requirements Application**

This Application included the following accounting policy changes:

| | | |
|---|---|---|
| Section 10 | Accounting and Other Policies – Sections 10.1 and 10.2 | Pages 82 - 89 |

As a result of the Revenue Requirement Decision, the Company adopted the following new accounting policies on a prospective basis.

i. Training and Feasibility Study Costs to be treated as O&M expense, rather than capital.
ii. All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time.
iii. Asset removal costs are recorded in operating and maintenance expense on the statement of earnings and comprehensive earnings. The annual amount of such costs approved for recovery in customer rates in 2010 is $5 thousand. Actual costs incurred in excess of or below the approved amount are to be recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates starting in 2012. For the year ended December 31, 2010, the Company incurred $9 thousand of actual removal costs, with $4 thousand being recorded in the deferral account. Prior to January 1, 2010, actual asset removal costs were recorded against accumulated amortization on the consolidated balance sheet.
iv. Gains and losses on the sale or removal of utility capital assets are recorded in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval. For the year ended December 31, 2010, $134 thousand of losses were deferred and recorded in the related long-term regulatory asset on the consolidated balance sheet. Prior to January 1, 2010, gains and losses on the sale or disposal of utility capital assets were recorded against accumulated amortization.

# Appendix D

# COMPANY SPECIFIC INFORMATION FOR FBC

## FortisBC Inc. ("FBC")

FBC is a company incorporated under the laws of the Province of British Columbia, operating since 1897. FBC is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and wholesale customers in more than 30 communities in the West Kootenay and Okanagan regions of South Central British Columbia, currently serving approximately 162,000 direct and indirect customers. FBC serves approximately 8 percent of electricity customers in BC and delivers approximately 6% percent of the Province's electricity. Table below summarizes FBC's company profile.

| | |
|---|---|
| **Type of Utility** | Integrated Electric Utility |
| **Energy Product Offering** | Electricity |
| **Service Area** | South Central |
| **Rate Base*** | $1,145,910 (000s) |
| **Sales/Transportation Volumes*** | 3,193 GWh |
| **Number of Customers*** | 116,105 (direct) |
| **Customer Additions*** | 2,128 |
| **Customer Growth Rate*** | 1.9% |
| **Customer Profile by Demand*** | |
| Residential | 40% |
| Commercial | 23% |
| Industrial | 8% |
| Wholesale | 29% |
| **Customer Profile by Sales Revenue*** | |
| Residential | 49% |
| Commercial | 23% |
| Industrial | 6% |
| Wholesale | 22% |

* Based on 2012 Forecast, 2012-2013 RRA, (November 4, 2011 Evidentiary Update)

## 1. Most recent Annual Report

- Canadian GAAP Annual Financial Statements for the Year-ended December 31, 2011
- Annual Information Form for the Year-ended December 31, 2011
- Management Discussion & Analysis for the Year-ended December 31, 2011

# FortisBC Inc.
# Consolidated Financial Statements
# For the years ended December 31, 2011 and 2010

# MANAGEMENT'S REPORT

The accompanying annual consolidated financial statements of FortisBC Inc. have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These annual consolidated financial statements were prepared in accordance with accounting principles generally accepted in Canada.

In meeting its responsibility for the reliability and integrity of the annual consolidated financial statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation focus on the need for training of qualified and professional employees and the effective communication of management guidelines and policies. The effectiveness of the internal controls of FortisBC Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit and Risk Committee (Audit Committee) which is composed of four independent directors and one director who is an officer of a related company. The Audit Committee oversees the external audit of the Corporation's annual consolidated financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholder's auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's annual consolidated financial statements are reviewed by the Audit Committee with each of management and the shareholder's auditors before the statements are recommended to the Board of Directors for approval. The shareholder's auditors have full and free access to the Audit Committee.

The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's annual consolidated financial statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholder's auditors' independence and auditors' fees.

The 2011 annual consolidated financial statements and Management Discussion and Analysis were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of FortisBC Inc.

Ernst & Young, LLP, independent auditors appointed by the shareholder of FortisBC Inc. upon recommendation of the Audit Committee, have performed an audit of the 2011 annual consolidated financial statements and their report follows.

(Signed by)
John Walker
President and Chief Executive Officer

(Signed by)
Michele Leeners
Vice President, Finance and Chief Financial Officer

Kelowna, Canada
February 7, 2012

# INDEPENDENT AUDITORS' REPORT

To the Shareholder of
**FortisBC Inc.**

We have audited the accompanying consolidated financial statements of **FortisBC Inc.**, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, and the consolidated statements of earnings and comprehensive earnings, retained earnings and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the consolidated financial statements**

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **FortisBC Inc.** as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Vancouver, Canada,
February 7, 2012.

Chartered Accountants

FORTIS BC

**FortisBC Inc.**
**CONSOLIDATED BALANCE SHEETS**

| As at December 31 (all amounts are in thousands of Canadian dollars) | 2011 | 2010 |
|---|---|---|
| **ASSETS** (note 12) | | |
| **Current assets** | | |
| Cash | **$ 4** | $ 18 |
| Accounts receivable (notes 5, 21 and 24) | **39,415** | 45,843 |
| Prepaid expenses | **928** | 1,119 |
| Other assets (note 7) | **505** | 566 |
| Materials and supplies | **439** | 467 |
| Regulatory assets (note 6) | **4,893** | 2,825 |
| Future income taxes (note 17) | **2,426** | 999 |
| | **48,610** | 51,837 |
| **Other assets** (note 7) | **10,457** | 11,383 |
| **Regulatory assets** (note 6) | **130,037** | 116,796 |
| **Property, plant and equipment** (note 8) | **1,094,525** | 1,048,952 |
| **Intangible assets** (note 9) | **41,208** | 41,264 |
| **Goodwill** (note 10) | **1,209** | 1,209 |
| **TOTAL ASSETS** | **$ 1,326,046** | $ 1,271,441 |
| **LIABILITIES AND SHAREHOLDER'S EQUITY** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges (notes 11, 21 and 24) | **$ 41,149** | $ 54,769 |
| Current portion of debt (note 12) | **24,504** | 2,049 |
| Current portion of obligation under capital lease (note 13) | **424** | 386 |
| Regulatory liabilities (note 6) | **7,267** | 2,771 |
| Income taxes payable | **4,638** | 2,117 |
| Future income taxes (note 17) | **1,631** | 1,019 |
| | **79,613** | 63,111 |
| **Long-term debt** (note 12) | **629,333** | 635,913 |
| **Obligation under capital lease** (note 13) | **25,510** | 25,356 |
| **Other post-employment benefits** (note 18) | **16,663** | 14,121 |
| **Regulatory liabilities** (note 6) | **751** | 1,082 |
| **Other liabilities** (note 14) | **7,395** | 6,537 |
| **Future income taxes** (note 17) | **101,616** | 91,654 |
| | **781,268** | 774,663 |
| **Shareholder's equity** | | |
| Share capital (note 15) | **201,851** | 201,851 |
| Retained earnings | **263,314** | 231,816 |
| | **465,165** | 433,667 |
| **TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY** | **$ 1,326,046** | $ 1,271,441 |

**Commitments and contingencies** (note 23)

**Approved on behalf of the Board:**

(Signed by) Harold Calla, Director

(Signed by) John Walker, Director

The accompanying notes are an integral part of these consolidated financial statements.

FORTIS BC

**FortisBC Inc.**

## CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE EARNINGS

| For the years ended December 31 (all amounts are in thousands of Canadian dollars) | 2011 | 2010 |
|---|---|---|
| **Revenues** (note 24) | | |
| Electricity revenue | $ 279,408 | $ 248,821 |
| Other revenue | 4,540 | 10,890 |
| | 283,948 | 259,711 |
| **Expenses** (note 24) | | |
| Power purchase costs | 71,581 | 72,975 |
| Operating costs | 70,773 | 63,873 |
| Depreciation and amortization (notes 6, 8 and 9) | 45,260 | 41,620 |
| | 187,614 | 178,468 |
| **Operating income** | 96,334 | 81,243 |
| Finance charges (note 12 and 16) | 39,440 | 35,298 |
| **Earnings before income taxes** | 56,894 | 45,945 |
| Income taxes (note 17) | 9,396 | 4,185 |
| **Net earnings and comprehensive earnings** | $ 47,498 | $ 41,760 |

## CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

| For the years ended December 31 (all amounts are in thousands of Canadian dollars) | 2011 | 2010 |
|---|---|---|
| **Retained earnings, beginning of year** | $ 231,816 | $ 205,056 |
| Net earnings | 47,498 | 41,760 |
| Dividends | (16,000) | (15,000) |
| **Retained earnings, end of year** | $ 263,314 | $ 231,816 |

The accompanying notes are an integral part of these consolidated financial statements.

FortisBC

**FortisBC Inc.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| For the years ended December 31 (all amounts are in thousands of Canadian dollars) | **2011** | 2010 |
|---|---|---|
| **Cash from (used in) operating activities** | | |
| Net earnings | **$ 47,498** | $ 41,760 |
| Adjustments for non-cash items: | | |
| Depreciation - property, plant and equipment (note 8) | **37,419** | 33,798 |
| Amortization - intangible assets (note 9) | **5,027** | 4,518 |
| Amortization - regulatory assets and liabilities (note 6) | **2,814** | 3,304 |
| Amortization - deferred financing costs (note 12) | **422** | 389 |
| Future income taxes | **(12)** | (16) |
| Other | **(1,083)** | (2,797) |
| Change in long-term regulatory assets and liabilities | **(3,844)** | (6,622) |
| Changes in non-cash working capital (note 19) | **7,726** | 754 |
| | **95,967** | 75,088 |
| **Cash from (used in) investing activities** | | |
| Change in other assets and other liabilities | **1,285** | 2,385 |
| Capital expenditures - property, plant and equipment (note 19) | **(97,604)** | (134,735) |
| Capital expenditures - intangible assets | **(4,971)** | (6,664) |
| Contributions in aid of construction | **5,880** | 7,368 |
| | **(95,410)** | (131,646) |
| **Cash from (used in) financing activities** | | |
| Proceeds from (repayment of) credit facilities | **16,356** | (36,661) |
| Proceeds from issuance of debentures | **-** | 100,000 |
| Deferred financing costs | **-** | (942) |
| Repayment of mortgage | **(927)** | (844) |
| Dividends paid | **(16,000)** | (15,000) |
| Issuance of common shares | **-** | 10,000 |
| | **(571)** | 56,553 |
| **Decrease in cash** | **(14)** | (5) |
| **Cash, opening balance** | **18** | 23 |
| **Cash, closing balance** | **$ 4** | $ 18 |

Supplementary Information to Consolidated Statements of Cash Flows (note 19).

The accompanying notes are an integral part of these consolidated financial statements.

## 1. DESCRIPTION OF THE BUSINESS

FortisBC Inc. ("FortisBC" or the "Corporation") was incorporated by an Act of the Legislature of British Columbia. The Corporation is a wholly-owned subsidiary of FortisBC Pacific Holdings Inc. ("FortisBC Pacific") which is an indirect wholly-owned subsidiary of Fortis Inc. ("Fortis"), a Canadian public company.

FortisBC is an integrated, regulated electric utility which owns and operates a network of generation, transmission and distribution assets located in the southern interior of British Columbia. The Corporation serves residential, general service, wholesale and industrial consumers of electricity. The Corporation's generation assets include four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 megawatts and a non-regulated 16 megawatt run-of-river hydroelectric generating plant near Lillooet, British Columbia. The Corporation's regulated transmission and distribution assets consist of a network of transmission and distribution power lines, substations and support structures.

## 2. NATURE OF REGULATION

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations, pursuant to the *Utilities Commission Act* (British Columbia) covering such matters as tariffs, rates, construction, operations, financing and accounting.

FortisBC operates primarily under a cost of service regulation as prescribed by the BCUC. The Corporation applies to the BCUC for annual revenue requirements based on estimated costs of service, including, but not limited to, operating expenses, power purchases, depreciation and amortization, income taxes, interest on debt and a return on equity ("ROE"). In addition, the regulatory framework through to the end of 2011 included some performance-based rate setting ("PBR") attributes. The 2011 allowed ROE was 9.90 per cent (2010 - 9.90 per cent) on a deemed capital structure of 40 per cent common equity (2010 - 40 per cent).

When the BCUC issues decisions affecting the financial statements, the effects of the decision are recorded in the period in which the decision is received.

## 3. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The consolidated financial statements include the accounts of the Corporation and its wholly-owned partnership and subsidiaries, Walden Power Partnership ("WPP"), ESI Power-Walden Corporation Ltd. and West Kootenay Power Ltd. All significant inter-company transactions and balances have been eliminated upon consolidation.

### Regulation

The Corporation's consolidated financial statements have been prepared in accordance with Canadian GAAP, including certain accounting treatments that differ from that for enterprises not subject to rate regulation. These differences are described in the significant accounting policies below and note 6.

### Cash

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of deposit.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

### Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on the accounts receivables balances. The Corporation maintains an accumulated provision for uncollectible customer accounts receivable that is estimated based on known accounts, historical experience and other currently available information, including events such as customer bankruptcy.

### Regulatory Assets and Liabilities

The BCUC has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are probable to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the BCUC could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. For regulatory assets and liabilities which are amortized, the amortization is approved by the BCUC. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

### Materials and Supplies

Materials and supplies includes inventory held for day-to-day operations and for the maintenance of property, plant and equipment. Inventory held for construction or used only in connection with an item of property, plant and equipment is classified as property, plant and equipment. Inventory is valued at the lower of average cost and net realizable value.

### Property, Plant and Equipment

Property, plant and equipment are recorded at cost, including Allowance for Funds Used During Construction and capitalized overhead, both of which are described below, less accumulated depreciation. Certain additions to property, plant and equipment are made with the assistance of non-refundable contributions in aid of construction ("CIAC") from customers when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers' specific requirements. Such amounts are recorded as a reduction of property, plant and equipment and are being amortized over the estimated service lives of the related assets by an offset against the provision for depreciation.

The main components of property, plant and equipment are as follows:

*Generation Assets*

Generation assets include hydroelectric generating stations, turbines, dams, reservoirs and other related equipment used to generate electricity.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

*Substation Assets*

Substation assets are transmission and distribution transformers used to transform electricity between high and low voltages.

*Transmission Assets*

Transmission assets include poles, conductors, support structures and other related equipment used to transmit electricity at higher voltages (generally at 60 kilovolts and above).

*Distribution Assets*

Distribution assets include poles, towers and fixtures, low-voltage transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment used to distribute electricity at lower voltages (generally below 60 kilovolts).

*General Assets*

General assets are those that relate to general equipment, office equipment and furniture, buildings, computer hardware and software, transportation equipment, tools and communications equipment.

*Allowance for Funds Used During Construction ("AFUDC")*

As permitted by the regulator, AFUDC is included in the cost of property, plant and equipment and intangible assets. Non-regulated operations generally capitalize AFUDC based on interest incurred on related debt. AFUDC recorded by the Corporation, which was $1.8 million for 2011 (2010 - $4.7 million), is based upon the Corporation's weighted average after tax cost of capital, which includes a return on equity and a cost of debt component. The Corporation's deducts the debt component of AFUDC from interest expense and recognizes the equity component of AFUDC in other revenue. The debt and equity components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable items of property, plant and equipment and intangible assets. The debt and equity components of AFUDC for 2011 were approximately $0.7 million (2010 - $1.9 million) and $1.1 million (2010 – $2.8 million) respectively.

*Capitalized Overhead*

Capitalized overhead includes some overhead costs which may not be directly attributable to specific items of property, plant and equipment and intangible assets but relate to the Corporation's overall capital program. The methodology of calculating capitalized overhead is approved by the regulator. Non-regulated operations are not permitted to capitalize overhead costs which are not directly attributable to construction activity. Capitalized overhead allocated to property, plant and equipment is depreciated based on the composite depreciation rate of the applicable asset category. Capitalized overhead allocated to intangible assets is amortized based on the composite amortization rate of the applicable asset category. In 2011, capitalized overhead was $10.8 million (2010 - $9.5 million).

*Depreciation*

Depreciation is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in property, plant and equipment in service at the beginning of the year. The application of these rates for the year ended December 31, 2011 resulted in a composite rate of 3.0 per cent (2010 - 3.1 per cent). No depreciation is provided on assets under construction.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

| December 31, 2011 | Service life range of utility asset classes (years) | Average remaining service life range of utility asset classes (years) |
|---|---|---|
| Generation | 45 to 75 | 40.0 |
| Substations | 50 to 55 | 29.1 |
| Transmission | 40 to 60 | 33.5 |
| Distribution | 20 to 50 | 26.7 |
| General | 5 to 40 | 8.0 |

*Retirement of Property, Plant and Equipment*

As permitted by the regulator, property, plant and equipment are depreciated using a group method. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. When an asset is retired, its net book value is charged to accumulated depreciation, with no gain or loss reflected in income unless the disposal is outside the normal course of business or involves a major item of property, plant and equipment. It is expected that future depreciation rates will be adjusted in the amount of the deferred gains or losses. Any gain or loss which is charged to accumulated depreciation will be reflected in future depreciation expense when it is refunded or collected in rates. In the absence of rate regulation, any gain or loss would be recorded as part of net earnings for the year, which would have resulted in a net loss on retirement of property, plant and equipment of $0.7 million for 2011 (2010 - $4.6 million).

*Costs of Removal and Site Restoration*

As permitted by the regulator, actual costs of removal and site restoration, net of salvage proceeds, are recorded against accumulated depreciation when incurred. In the absence of regulation, removal and site restoration costs would have been expensed as incurred rather than over the life of the asset through depreciation expense. During 2011, actual removal and site restoration costs of $5.3 million (2010 - $7.9 million), net of salvage proceeds of $0.2 million (2010 - $1.4 million), was recorded in accumulated depreciation. In the absence of rate regulation, operating costs would have been $5.3 million (2010 - $7.9 million) higher.

### Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Under Canadian GAAP, the Corporation does not have any arrangements that qualify as leases by conveying the right to use a specific asset pursuant to Emerging Issues Committee-150, *Determining Whether an Arrangement Contains a Lease* which became effective for arrangements entered into or modified after April 1, 2005.

Capital leases are amortized over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are amortized over the estimated service life of the underlying asset. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term, with the exception of the Trail Office Building lease as described in notes 6 and 23.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

### Intangible Assets

Intangible assets are comprised of right of ways and software not directly attributable to the operation of property, plant and equipment and are recorded at cost less accumulated amortization. Included in the cost of intangible assets are AFUDC and capitalized overhead, as explained under property, plant and equipment above.

Intangible assets subject to amortization are tested for recoverability as long-lived assets. Certain right of ways, with indefinite lives, are not subject to amortization and are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired. The impairment loss is calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Amortization is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in intangibles at the beginning of the year. The application of these rates for the year ended December 31, 2011 resulted in a composite rate of 8.2 per cent (2010 - 8.2 per cent).

| December 31, 2011 | Service life range of intangible asset classes (years) | Average remaining service life range of intangible asset classes (years) |
|---|---|---|
| Right of ways | 70 to 75 | 37.9 |
| Software | 5 to 10 | 4.7 |

Upon retirement of intangible assets, the net book value is charged to accumulated amortization, with no gain or loss reflected in income unless the disposal is outside the normal course of business. It is expected that future amortization rates will be adjusted in the amount of the deferred gains or losses. Any gain or loss which is charged to accumulated amortization will be reflected in future amortization expense when it is refunded or collected in rates.

### Impairment of Long-lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. There was no impairment of long-lived assets for the years ended December 31, 2011 and 2010.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return on capital or assets, is provided through customer electricity rates approved by the regulator. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility

### Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair values of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Goodwill is not amortized, but is tested for impairment annually or more frequently if events or changes in circumstances indicate that the goodwill might be impaired. Any impairment provision is charged to earnings.

To assess for impairment, the fair value of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. The annual impairment test was performed as at October 1, 2011. No goodwill impairment provision has been determined for the years ended December 31, 2011 and 2010.

### Asset Retirement Obligations

Asset retirement obligation ("ARO") costs are recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. The Corporation recognizes the fair value of a future ARO as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Corporation concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the ARO is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the ARO is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are recognized in a regulatory asset using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

During 2010 the Corporation obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of polychlorinated biphenyls ("PCBs") from certain of its electric equipment.

The Corporation has AROs for which the obligations cannot be reasonably estimated at this time. These AROs are primarily associated with the Corporation's hydroelectric generating facilities and assets associated with interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal asset retirement obligations (i.e. land and environmental remediation and/or removal of assets), the final date of removal of the related assets and the costs to do so cannot be reasonably determined at this time.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

### Revenue Recognition

Electricity revenue is billed at rates approved by the BCUC and is bundled to include the cost of generating, transmitting and distributing electricity. In addition, the rate includes customer service as well as other corporate and service functions.

Electricity is metered upon delivery to customers and is recognized as revenue when consumed using rates approved by the BCUC. Meters are read bi-monthly for the majority of FortisBC's customers, with the remainder read monthly, and bills are issued to customers based on these readings. At the end of each reporting period a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue at each reporting date. The estimation process for unbilled electricity consumption will result in adjustments to estimates of electricity revenues in the periods they become known.

### Employee Future Benefits

The Corporation has three defined benefit plans providing pensions to the majority of its employees as well as supplemental pensions to certain senior employees. The Corporation provides unfunded other post-employment benefits ("OPEBs") to certain of its retired employees including health and dental coverage, provincial medical premiums and life insurance. These plans are accounted for using the method recommended by the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3461. Benefits earned by employees are actuarially determined as the employees provide service. The Corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets.

The unrecognized transition obligations, together with adjustments arising from plan amendments, changes in assumptions and the excess of cumulative net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the fair value of the plan assets, are amortized on a straight-line basis over the expected average remaining service life of the employees covered by the plans. The average remaining service life of the employees covered by these plans ranges from 7 to 15 years. The Corporation uses a measurement date of September 30 for all of its plans.

All accrued obligations for defined benefit plans, supplemental arrangements and OPEBs are determined by independent actuaries using the projected benefits method prorated on service. In valuing the cost of these obligations, the Corporation uses management's best estimate assumptions, except for the liability discount rate where the Corporation uses the long-term market rate at the measurement date of high quality fixed income investments with a term to maturity similar to the covered benefits. Quoted market values where available are used to value pension assets.

The Corporation also provides a defined contribution pension arrangement to certain employees not covered by the defined benefit plans. Defined contribution plan costs are expensed by the Corporation as contributions are payable.

### Financial Instruments

FortisBC has designated its financial instruments as follows:

- Cash is classified as *"Held for Trading"*. Due to its nature, the carrying value equals its fair value.
- Accounts receivable, security deposits, employee loans and energy management loans are classified as *"Loans and Receivables"*. These financial assets are recorded at values that approximate their amortized cost using the effective interest method.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

- Accounts payable and accrued charges, operating credit and overdraft facilities, secured and unsecured debentures and mortgage obligations are classified as *"Other Financial Liabilities"*. These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.

### Energy Management Loans

Loans to residential and general service customers for energy efficiency initiatives and related products are interest bearing and range in terms from one to ten years.

### Financing Costs

Costs incurred to arrange debt financing are applied against the carrying value of the related debt, which are accounted for using the effective interest method over the life of the financial liability.

### Income Taxes

As ordered by the BCUC, the Corporation follows the taxes payable method of accounting for income taxes on regulated earnings for rate setting purposes. Under this method, the current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year. In addition, certain regulatory assets and deferred charges are recorded net of their income tax impact, with the offset charged to income tax expense. Under this methodology, customer rates do not include the recovery of future income taxes related to timing differences between the tax basis of regulated assets and liabilities and their carrying amounts for accounting purposes, other than for the regulatory assets and deferred charges recorded net of their income tax impacts.

As required by Canadian GAAP, the Corporation follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. As a result of rate regulation, future income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. It is expected that when these amounts become payable, they will be recovered through future rates.

### Use of Estimates

The preparation of the Corporation's financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the periods. The estimates relate to regulation, unbilled electricity deliveries, the useful life of property, plant and equipment, intangibles, goodwill, AROs, income taxes and employee future benefits, among other things. Certain estimates are also necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, is determined pursuant to subsequent regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty. The effect on the financial statements of changes in such estimates in future periods could be material and are recorded in the period they became known.

## 3. SIGNIFICANT ACCOUNTING POLICIES (continued)

### New Accounting Policies

Effective January 1, 2011, the Corporation adopted the following new accounting standard issued by the CICA.

*Business Combinations*

In January 2009, Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-Controlling Interests* were issued. These new standards are effective for fiscal years beginning on or after January 1, 2011. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have an impact on the Corporation's net earnings or consolidated balance sheet in the current period but will affect the recognition of business combinations completed by the Corporation in the future.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of sections 1601 and 1602 did not have an impact on the Corporation's net earnings or consolidated balance sheet in the current period but may affect the recognition of business combinations completed by the Corporation in the future.

## 4. FUTURE ACCOUNTING CHANGES

*Adoption of New Accounting Standards*

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011; however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"). As a qualifying entity with rate-regulated activities, FortisBC elected to opt for the one-year deferral and, therefore, continued to prepare its consolidated financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the IASB, FortisBC evaluated the option of adopting United States generally accepted accounting principles ("US GAAP"), as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012. Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a US Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 4. FUTURE ACCOUNTING CHANGES (continued)

SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is not currently an SEC Issuer. Therefore, on June 6, 2011, the Corporation, in coordination with its ultimate parent Fortis, filed an application with the Ontario Securities Commission (the "OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit the Corporation to prepare its financial statements in accordance with US GAAP without qualifying as an SEC Issuer ("the Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (a) January 1, 2015; or (b) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently relies primarily on US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. FortisBC believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

## 5. ACCOUNTS RECEIVABLE

Accounts receivable represents amounts billed and unbilled which are due from customers in the normal course of business. The Corporation bills customers for electricity consumption in arrears. Unbilled revenue represents an estimate of the value of customer electricity consumption not yet billed.

The components of trade accounts receivable are as follows:

| | | **2011** | | 2010 |
|---|---|---|---|---|
| Billed revenue | **$** | **24,416** | $ | 28,309 |
| Unbilled revenue | | **15,086** | | 17,783 |
| Amounts due from related parties (see note 24) | | **863** | | 809 |
| | | **40,365** | | 46,901 |
| Less: allowance for doubtful accounts | | **950** | | 1,058 |
| | **$** | **39,415** | $ | 45,843 |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 6. REGULATORY ASSETS AND LIABILITIES

Based on existing regulatory orders or the expectation of future regulatory orders, the Corporation has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers:

| **Regulatory assets** | **2011** | 2010 | **Remaining Recovery Period (years) as at December 31, 2011** |
|---|---|---|---|
| Energy management costs | **$ 11,416** | $ 8,433 | 10 |
| Regulatory other post-employment benefits asset | **7,309** | 7,011 | 7 |
| Brilliant Terminal Station lease costs | **5,614** | 5,098 | 30 |
| Trail office building lease costs | **1,104** | 1,249 | 12 |
| Future income taxes | **99,203** | 90,044 | Ongoing |
| Other recoverable costs | **10,284** | 7,786 | 1-13 |
| | **134,930** | 119,621 | |
| Less: current portion | **4,893** | 2,825 | |
| | **$ 130,037** | $ 116,796 | |

| **Regulatory liabilities** | **2011** | 2010 | **Remaining Settlement period (years) as at December 31, 2011** |
|---|---|---|---|
| 2011 regulatory incentives | **$ 6,887** | $ - | 1 |
| 2010 regulatory incentives | **380** | 2,061 | 1 |
| 2009 regulatory incentives | **-** | 1,090 | - |
| Financing costs under effective interest method | **751** | 702 | 39 |
| | **8,018** | 3,853 | |
| Less: current portion | **7,267** | 2,771 | |
| | **$ 751** | $ 1,082 | |

During the year, amortization of regulatory assets of $2.8 million (2010 - $3.3 million) was recorded.

The Corporation's recognition of certain revenues and expenses as a result of rate regulation differs from that otherwise recognized using Canadian GAAP for entities not subject to rate regulation. In the absence of rate regulation, the regulatory assets and regulatory liabilities would not be recorded, resulting in an increase in 2011 other revenues of $4.1 million (2010 - decrease of $0.6 million), an increase in 2011 operating costs of $6.9 million (2010 - $6.1 million), an increase in 2011 depreciation expense of $1.3 million (2010 - $0.9 million), a decrease in 2011 amortization expense of $2.9 million (2010 - $3.3 million), an increase in 2011 finance charges of $2.5 million (2010 - $2.1 million), an increase in 2011 income tax expense of $5.4 million (2010 - $7.1 million) and a decrease in 2011 property, plant and equipment of $0.2 million (2010 - $nil). The components of these cumulative effects are detailed below.

## 6. REGULATORY ASSETS AND LIABILITIES (continued)

### Energy Management Costs

The Corporation provides energy management services to promote energy efficiency programs for its customers. As required by BCUC order, the Corporation has capitalized all expenditures (except certain defined costs) and the regulatory asset represents the unamortized balance of the energy management program. The unamortized energy management costs are expected to be recovered from customers in future rates over an average of 10 years.

In the absence of rate regulation, the costs of the energy management services would have been expensed as incurred which would have resulted in increased 2011 operating costs of $5.9 million (2010 - $3.7 million), decreased 2011 amortization expense of $1.4 million (2010 - $2.3 million) and decreased 2011 income tax expense of $1.5 million (2010 - $1.1 million).

### Regulatory OPEB Asset

In prior years, the Corporation has not collected in customer rates the full accrual cost of OPEBs. The regulatory OPEB asset balance represents the deferred portion of the expense relating to OPEBs that is expected to be recovered from customers in future rates. Upon recovery in future rates, these deferred costs will be expensed.

In the absence of rate regulation, the full accrued cost of OPEBs would be expensed, which would have resulted in decreased 2011 operating costs of $0.5 million (2010 - $0.5 million) and increased 2011 income tax expense of $0.8 million (2010 - $0.7 million). The regulatory asset balance is expected to be recovered from customers in future rates but it is not included in the return on investment of the Corporation's rate base.

### Brilliant Terminal Station ("BTS") Lease Costs

The depreciation on the BTS capital lease asset (see note 8), the interest expense associated with the BTS obligation (see note 13) and the related operating costs are not being fully recovered by the Corporation in current customer rates since those rates include only the recovery of the BTS as an operating lease. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates over the term of the arrangement. Of the $2.4 million (2010 - $2.2 million) of interest expense relating to the BTS obligation and $0.7 million (2010 - $0.9 million) of depreciation expense relating to the BTS capital lease asset, a total of $2.6 million (2010 - $2.6 million) was recognized in operating costs for 2011, as approved by the BCUC, with the balance of $0.5 million (2010 - $0.6 million) deferred as part of the regulatory asset balance.

In the absence of rate regulation, depreciation on the BTS capital lease asset and interest on the BTS obligation would be recorded, resulting in a decrease in 2011 operating costs of $2.6 million (2010 - $2.6 million), an increase in 2011 depreciation expense of $0.7 million (2010 - $0.9 million) and an increase in 2011 finance charges of $2.4 million (2010 - $2.2 million). The regulatory asset balance is expected to be recovered from customers in future rates but it is not included in the return on investment of the Corporation's rate base.

### Trail Office Building Lease Costs

Under a sale-leaseback agreement, on September 29, 1993 the Corporation began leasing its Trail, BC office building for a term of 30 years (see note 23). The Corporation accounts for the agreement as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease

## 6. REGULATORY ASSETS AND LIABILITIES (continued)

term. As ordered by the BCUC, the Corporation recovers the Trail office lease payments from customers and records the lease costs on a cash basis. This regulatory asset represents the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase.

In the absence of rate regulation, these lease costs would be recorded on a straight-line basis which would result in a decrease in 2011 operating costs of $0.2 million (2010 - $0.2 million). The regulatory asset balance is expected to be recovered from customers in future rates but it is not included in the return on investment of the Corporation's rate base.

### Future Income Taxes

The Corporation follows the asset and liability method of accounting for income taxes for its rate-regulated operations. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities. As a result, future income taxes incurred related to regulated operations has been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings.

In the absence of rate regulation, future income taxes would have been expensed as recognized which would have resulted in an increase to 2011 income tax expense of $6.9 million (2010 - $8.0 million). The income tax expense in absence of rate regulation would exclude the $2.2 million in 2011 (2010 - $2.4 million) associated with income taxes that will become payable on future revenue as they are collected from customers when the tax timing differences reverse. The regulatory asset balance is expected to be recovered from customers in future rates when the future taxes become payable, but it is not included in the return on investment of the Corporation's rate base.

### Other Recoverable Costs

This balance includes deferral of other costs which have either been approved by the BCUC for deferral and amortization or are expected to be approved. Other recoverable costs include costs associated with the long-term transmission and distribution system plan development, deferred projects, the rate application proceedings, the mountain pine beetle hazardous tree removal costs, deferred costs relating to the Corporation's revenue protection program (including power diversion inspections, cost of audits for unmetered services, instrument meters and system losses), depreciation and accretion on the asset retirement obligation and other miscellaneous project costs. Other recoverable costs also includes the income tax impacts of the Corporation's prepaid pension costs and deferred financing costs, which have been approved by the BCUC to be included in future customer rates.

In the absence of rate regulation, these costs would have been expensed as incurred which would have resulted in an increase in 2011 operating costs of $4.3 million (2010 - $5.7 million), an increase in 2011 depreciation expense of $0.6 million (2010 - $nil), a decrease in 2011 amortization expense of $1.5 million (2010 - $1.0 million), an increase in 2011 finance charges of $0.1 million (2010 - $nil), a decrease in 2011 income taxes of $0.8 million (2010 - $0.5 million) and a decrease in 2011 property, plant and equipment of $0.2 million (2010 - $nil).

### Regulatory Incentives

Under the terms of the PBR agreement which ended December 31, 2011, variances in certain revenues and costs as compared to the forecast were deferred as regulatory incentive assets or regulatory incentive liabilities and recovered from (refunded to) customers in future customer rates. In addition, the ROE

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 6. REGULATORY ASSETS AND LIABILITIES (continued)

resulting from actual financial performance was compared to the Corporation's allowed ROE and variances, positive or negative (adjusting for certain revenue and cost variances which flow through to customers), up to a 2 per cent collar, was shared equally between customers and FortisBC and deferred as regulatory incentive assets or regulatory incentive liabilities. Final disposition of amounts deferred as regulatory incentive assets and regulatory incentive liabilities will generally occur in the following year.

The 2009 regulatory incentive liability of $1.1 million and current portion of the 2010 regulatory incentive liability of $1.7 million were approved by the BCUC for repayment through reductions in 2011 electricity revenue, with an offsetting increase in other revenue. The remaining $0.4 million of the 2010 regulatory incentive liability is expected to be approved by the BCUC for settlement in 2012 by a reduction to 2012 electricity revenue. In the absence of rate regulation, the regulatory incentive amounts would not be recorded, which would have decreased other revenue by $2.8 million (2010 - $2.7 million).

Based on the PBR framework which ended December 31, 2011, the current portion of the 2011 regulatory incentive liability is expected to be approved by the BCUC for settlement in 2012 in the amount of $6.9 million by a reduction in 2012 electricity revenue. In the absence of the PBR framework, the regulatory incentive amount would not be recorded, which would have increased other revenue by $6.9 million in 2011 (2010 - $2.1 million).

### Financing Costs Under Effective Interest Method

This balance represents the cumulative difference between applying the effective interest method for amortizing financing costs under CICA 3855 and the straight-line amortization method prescribed by the regulator. This regulatory liability represents the cumulative difference between the two amortization methods which will be refunded to customers over the term of the outstanding debt through future rates.

In the absence of rate regulation, finance charges would have decreased by $nil in 2011 (2010 - $0.1 million). The regulatory liability balance is expected to be refunded to customers in future rates but it is not included in the return on investment of the Corporation's rate base.

## 7. OTHER ASSETS

| | **2011** | 2010 |
|---|---|---|
| Energy management loans | **$ 2,447** | $ 3,208 |
| Prepaid pension costs (note 18) | **8,515** | 8,741 |
| | **10,962** | 11,949 |
| Less: current portion | **505** | 566 |
| | **$ 10,457** | $ 11,383 |

The current portion of other assets relate to energy management loans expected to be collected within the next year.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 8. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2011 | Cost | Accumulated Depreciation | Book Value |
|---|---|---|---|
| Generation | $ 252,441 | $ 50,920 | $ 201,521 |
| Substations | 410,108 | 80,875 | 329,233 |
| Transmission | 183,751 | 38,798 | 144,953 |
| Distribution | 388,753 | 72,358 | 316,395 |
| General | 124,120 | 47,651 | 76,469 |
| Asset under capital lease | 28,087 | 7,768 | 20,319 |
| Assets under construction | 5,635 | - | 5,635 |
| | **$ 1,392,895** | **$ 298,370** | **$ 1,094,525** |

| December 31, 2010 | Cost | Accumulated Depreciation | Book Value |
|---|---|---|---|
| Generation | $ 224,031 | $ 47,818 | $ 176,213 |
| Substations | 353,811 | 73,543 | 280,268 |
| Transmission | 178,125 | 33,648 | 144,477 |
| Distribution | 367,254 | 67,402 | 299,852 |
| General | 116,490 | 41,897 | 74,593 |
| Asset under capital lease | 27,689 | 7,045 | 20,644 |
| Assets under construction | 52,905 | - | 52,905 |
| | **$ 1,320,305** | **$ 271,353** | **$ 1,048,952** |

Included in general property, plant and equipment is $6.0 million (2010 - $5.3 million) of materials and supplies held for construction or used only in connection with an item of property, plant and equipment.

Included in property, plant and equipment are gross asset retirement costs totalling $4.0 million (2010 - $3.2 million) which were recognized during 2011. Depreciation of $0.6 million (2010 - $0.3 million) on the asset retirement costs was recorded in other recoverable costs in regulatory assets (see note 6). The corresponding liability has been recorded as an ARO in other liabilities (see note 14).

During 2011, depreciation of property, plant and equipment of $37.4 million (2010 - $33.8 million) was recognized in earnings. Depreciation of $0.7 million (2010 - $0.9 million) on the asset under capital lease was recorded in Brilliant Terminal Station lease costs as a regulatory asset (see note 6).

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 9. INTANGIBLE ASSETS

| **December 31, 2011** | **Cost** | **Accumulated Amortization** | **Book Value** |
|---|---|---|---|
| Right of ways | $ 27,455 | $ 2,268 | $ 25,187 |
| Software | 48,866 | 32,845 | 16,021 |
| | **$ 76,321** | **$ 35,113** | **$ 41,208** |

| **December 31, 2010** | **Cost** | **Accumulated Amortization** | **Book Value** |
|---|---|---|---|
| Right of ways | $ 27,121 | $ 1,929 | $ 25,192 |
| Software | 44,229 | 28,157 | 16,072 |
| | **$ 71,350** | **$ 30,086** | **$ 41,264** |

There was no impairment of intangible assets in 2011 and 2010.

During 2011, amortization of intangibles of $5.0 million (2010 - $4.5 million) was recorded. Included in the cost of right of ways at December 31, 2011 was $10.2 million (December 31, 2010 - $10.0 million) not subject to amortization.

## 10. GOODWILL

Goodwill of $1.2 million was acquired through the acquisition of Princeton Light & Power Company, Limited on December 31, 2006. There was no impairment of goodwill in 2011 and 2010.

## 11. ACCOUNTS PAYABLE AND ACCRUED CHARGES

| | **2011** | 2010 |
|---|---|---|
| Trade accounts payable | **$ 14,049** | $ 25,307 |
| Other accrued charges | **21,668** | 24,604 |
| Accrued interest | **4,545** | 4,545 |
| Amounts due to related parties (see note 24) | **887** | 313 |
| | **$ 41,149** | $ 54,769 |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 12. LONG-TERM DEBT

| | 2011 | 2010 |
|---|---|---|
| Secured Debentures | | |
| Series F 9.65% due October 16, 2012 | **$ 15,000** | $ 15,000 |
| Series G 8.8% due August 28, 2023 | **25,000** | 25,000 |
| WPP mortgage 9.44% due October 31, 2013 | **1,943** | 2,870 |
| | **41,943** | 42,870 |
| Unsecured Debentures | | |
| Series H 8.77% due February 1, 2016 | **25,000** | 25,000 |
| Series I 7.81% due December 1, 2021 | **25,000** | 25,000 |
| Series 04-1 5.48% due November 28, 2014 | **140,000** | 140,000 |
| Series 05-1 5.60% due November 9, 2035 | **100,000** | 100,000 |
| Series 07-1 5.90% due July 4, 2047 | **105,000** | 105,000 |
| Medium Term Note Debentures Series 1 6.10% due June 2, 2039 | **105,000** | 105,000 |
| Medium Term Note Debentures Series 2 5.00% due November 24, 2050 | **100,000** | 100,000 |
| | **600,000** | 600,000 |
| Operating credit facilities | **8,992** | - |
| Overdraft facility | **8,486** | 1,122 |
| | **17,478** | 1,122 |
| Total debt | **659,421** | 643,992 |
| Less: current portion of debt | **24,504** | 2,049 |
| | **634,917** | 641,943 |
| Less: deferred financing costs | **5,584** | 6,030 |
| Long term debt | **$ 629,333** | $ 635,913 |

### Secured and Unsecured Debentures

The Series F and G secured debentures are collateralized by a fixed and floating first charge on the assets of the Corporation. The secured Series F and G and unsecured Series H and I debentures are guaranteed by FortisWest Inc., a subsidiary of Fortis.

The WPP mortgage is collateralized by a fixed and floating charge over the assets of WPP, FortisBC's wholly-owned partnership.

On November 19, 2010, FortisBC entered into an agreement to sell $100.0 million of senior unsecured Medium Term Note Debentures Series 2 which bear interest at a rate of 5.00 per cent to be paid semi-annually and mature on November 24, 2050. The closing of the issuance occurred on November 24, 2010, with net proceeds of $99.3 million being used to repay existing bank indebtedness and finance the capital expenditure program and working capital requirements.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 12. LONG-TERM DEBT (continued)

### Operating Credit Facilities and Overdraft Facility

On April 28, 2011, the Corporation amended its operating credit facility provided by a syndicate of Canadian Chartered Banks. The amended operating credit facility is comprised of a $100.0 million three-year revolving facility maturing on May 7, 2014 (“Facility A”) and a $50.0 million, 364-day revolving facility maturing on May 3, 2012 (“Facility B”). Two years prior to the current Facility A maturity date, the Corporation may request an extension of the maturity date for Facility A for a further period of 364 days and if the request for extension is not granted, all amounts outstanding under Facility A become due on the Facility A maturity date. Similarly, prior to the current Facility B maturity date, the Corporation may request the lenders to extend the term for an additional 364 days and if the request for extension is not granted, Facility B will automatically convert into a non-revolving term credit facility that will mature six months from that date. The operating credit facility also allows the Corporation to request that the lenders provide up to $50.0 million of additional financing under Facility A or Facility B or a combination of the two facilities.

Borrowings under the Corporation’s operating credit facilities bear interest at prime plus a margin or the certificate of deposit offered rate for bankers’ acceptances plus a margin. The margin applied is based on FortisBC’s debt ratings provided by its credit rating agencies. The operating credit facilities are also available to support letters of credit.

The overdraft facility is an unsecured $10.0 million demand credit facility which bears interest at prime. The interest rate on the balance outstanding at December 31, 2011 is 3.00 per cent (December 31, 2010 - 3.00 per cent).

As of December 31, 2011, $142.5 million was available against the combined operating credit and demand overdraft facilities (December 31, 2010 - $158.8 million) and $nil (December 31, 2010 - $nil) was used to support outstanding letters of credit.

### Deferred Financing Costs

During the year ended December 31, 2011, amortization of deferred financing costs of $0.4 million (2010 - $0.4 million) was recognized in finance charges (see note 16).

### Fair Values

As at December 31, 2011, the fair value of FortisBC debt exceeded the carrying value by $155.6 million (December 31, 2010 - the fair value exceeded the carrying value by $82.4 million) (see note 21).

Principal payments required over the next five years and thereafter are as follows:

| **Year** | **Principal Repayments and Maturing Issues of Debt** |
|---|---|
| 2012 | $ 24,504 |
| 2013 | 925 |
| 2014 | 148,992 |
| 2015 | - |
| 2016 | 25,000 |
| Thereafter | 460,000 |
| | **$ 659,421** |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 13. OBLIGATION UNDER CAPITAL LEASE

On July 15, 2003, the Corporation began operating the BTS, under an agreement the term of which expires in 2056 (unless the Corporation has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination) (the "BTS Obligation"). The BTS is jointly owned by the Columbia Power Corporation and the Columbia Basin Trust (the "Owners") and used by the Corporation on its own behalf and on behalf of the Owners. The agreement provides that FortisBC will pay the Owners a charge related to the recovery of the capital cost of the BTS and related operating costs. The BTS Obligation bears interest at a composite rate of 8.62 per cent.

Included in operating costs was $2.6 million (2010 - $2.6 million) relating to the BTS agreement as described in note 6. The Corporation's future minimum lease payments for the BTS Obligation under capital lease for the next five years and thereafter are as follows:

| | Amount |
|---|---|
| 2012 | $ 3,160 |
| 2013 | 3,192 |
| 2014 | 3,213 |
| 2015 | 3,236 |
| 2016 | 3,259 |
| Thereafter | 71,064 |
| | 87,124 |
| Less: amount representing imputed interest and executory costs | 61,190 |
| Total obligation under capital lease | 25,934 |
| Less: current portion of obligation under capital lease | 424 |
| | **$ 25,510** |

## 14. OTHER LIABILITIES

| | **2011** | 2010 |
|---|---|---|
| Asset retirement obligation | **$ 3,935** | $ 3,219 |
| Accrued pension costs (note 18) | **1,535** | 1,292 |
| Other liabilities | **1,925** | 2,026 |
| | **$ 7,395** | $ 6,537 |

### Asset Retirement Obligation ("ARO")

During 2010, FortisBC obtained sufficient information to recognize an ARO based on an estimate of the fair value and timing of estimated future expenditures associated with the removal of insulating oil in certain electrical equipment that is contaminated with PCBs. The determination of the ARO was based on recently enacted PCB regulations under the *Canadian Environmental Protection Act, 1999* which govern the management and storage of PCBs as well as impose timelines for disposal based on certain criteria including type of equipment, in-use status and PCB-contamination thresholds. The Corporation must identify and remove certain levels of PCBs in certain of its electrical equipment assets by 2014 and others by 2025 to be compliant with the PCB regulations.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 14. OTHER LIABILITIES (continued)

Consistent with its accounting policy for AROs, FortisBC records an ARO liability in the period in which it is incurred if a reasonable estimate of fair value can be determined. The Corporation's ARO was based on a best estimate of the present value of the future expenditures expected to be required to comply with existing regulations.

Changes in the Corporation's AROs are summarized below:

| | **2011** | 2010 |
|---|---|---|
| Asset retirement obligation at beginning of year | **$ 3,219** | $ - |
| Obligations incurred | **-** | 3,355 |
| Interest accretion | **84** | 41 |
| Expenditures | **(226)** | - |
| Revisions to estimates | **858** | (177) |
| Asset retirement obligation at end of year | **$ 3,935** | $ 3,219 |

The ARO has been recorded in other liabilities, while the asset retirement cost has been capitalized to property, plant and equipment (see note 8). Actual costs incurred upon settlement of an ARO are charged against the related liability to the extent of the accrued balance. Any difference between the actual costs incurred upon settlement of the ARO and the remaining balance is expected to be recognized as a regulatory asset or liability at that time.

The Corporation's recognition of certain revenues and expenses as a result of rate regulation differs from that otherwise recognized using Canadian GAAP for entities not subject to rate regulation. The future amounts of the accretion expense associated with the ARO and future depreciation expense associated with the asset retirement cost will accumulate and be deferred as a regulatory asset to be recovered by customers in future rates. Upon recovery in rates, these deferred costs will be expensed.

Total estimated undiscounted future cash flows required to comply with the PCB regulations is approximately $4.8 million. These expenditures are expected to be incurred over the period from 2012 to 2025 as follows:

| | **Amount** |
|---|---|
| 2012 | $ 966 |
| 2013 | 1,012 |
| 2014 | 1,620 |
| 2015 | 96 |
| 2016 | 98 |
| Thereafter | 974 |
| | **$ 4,766** |

The credit-adjusted risk-free discount rates used to calculate the present value of the above obligation ranges from 3.8 per cent to 5.5 per cent depending on the appropriate rate for the period over which the obligation is expected to be settled. There are uncertainties in estimating future asset retirement costs due

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 14. OTHER LIABILITIES (continued)

to the use of assumptions. All factors used in estimating the Corporation's ARO represent management's best estimate of the costs required to meet existing legislation or regulations. It is possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Corporation's current assumptions.

## 15. SHARE CAPITAL

AUTHORIZED
500,000,000 Common shares, with a par value of $100 each
500,000,000 Preferred shares, with a par value of $25 each, issuable in series

| ISSUED | **2011** | 2010 |
|---|---|---|
| 2,018,510 Common shares (2010 - 2,018,510 Common shares) | **$ 201,851** | $ 201,851 |

During 2011, the Corporation issued nil (2010 - 100,000) common shares for cash consideration of $nil (2010 - $10.0 million) and paid dividends of $16.0 million (2010 - $15.0 million) to its parent company FortisBC Pacific.

## 16. FINANCE CHARGES

| | **2011** | 2010 |
|---|---|---|
| Interest on long-term debt | **$ 39,315** | $ 36,128 |
| Interest on short-term debt | **453** | 717 |
| Amortization of deferred financing costs | **422** | 389 |
| Allowance for funds used during construction - debt component | **(750)** | (1,936) |
| | **$ 39,440** | $ 35,298 |

## 17. INCOME TAXES

Future income taxes are provided for temporary differences. Future income tax assets and liabilities comprised the following:

| | **2011** | 2010 |
|---|---|---|
| Future income tax liability (asset) | | |
| Property, plant and equipment | **$ 92,122** | $ 81,456 |
| Intangibles | **6,905** | 7,047 |
| Regulatory assets | **2,222** | 1,837 |
| Regulatory liabilities | **(2,426)** | (999) |
| Other | **1,998** | 2,333 |
| Net future income tax liability | **$ 100,821** | $ 91,674 |
| | | |
| Classification | | |
| Current future income tax asset | **$ (2,426)** | $ (999) |
| Current future income tax liability | **1,631** | 1,019 |
| Long-term future income tax liability | **101,616** | 91,654 |
| Net future income tax liability | **$ 100,821** | $ 91,674 |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 17. INCOME TAXES (continued)

The long-term future income tax liability as at December 31, 2011 includes $1.6 million (2010 - $1.6 million) related to non-regulated operations.

The components of the provision for income taxes were as follows:

| | 2011 | 2010 |
|---|---|---|
| Current taxes | $ 9,408 | $ 4,201 |
| Future income taxes | 9,147 | 10,421 |
| Less regulatory adjustment | (9,159) | (10,437) |
| Future income tax recovery | (12) | (16) |
| Income tax expense | $ 9,396 | $ 4,185 |

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory tax rate to earnings before corporate taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes:

| | 2011 | 2010 |
|---|---|---|
| Combined Canadian federal and provincial statutory income tax rate | 26.5% | 28.5% |
| Statutory income tax rate applied to earnings before corporate taxes | $ 15,077 | $ 13,094 |
| Items capitalized for accounting but expensed for income tax purposes | (3,342) | (4,065) |
| Difference between capital cost allowance and amounts claimed for accounting purposes | (4,031) | (4,201) |
| Other | 1,692 | (643) |
| Income tax expense | $ 9,396 | $ 4,185 |
| Effective tax rate | 16.5% | 9.1% |

As at December 31, 2011, the Corporation had no non-capital or capital loss carryforwards.

## 18. EMPLOYEE FUTURE BENEFITS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental pension arrangements, and defined contribution plans. The Corporation also provides post-employment benefits other than pensions for certain of its retired employees. The following is a summary of each type of plan:

### Defined Benefit Pension Plans

The Corporation sponsors three contributory defined benefit pension plans, one of which is closed to new entrants. The plans provide benefits based on a percentage of employees' final average earnings and the number of years of service. The most recent actuarial valuations of the plans for funding purposes were undertaken as of December 31, 2010. The next actuarial valuations of the plans for funding purposes are to be completed effective December 31, 2013. The Corporation's policy is to fund the defined benefit plans on an actuarial basis in accordance with pension standards legislation, in order to accumulate assets sufficient to meet the benefits to be paid.

### Supplemental Pension Arrangements

Certain employees of the Corporation are eligible to receive supplemental benefits which provide pension benefits in excess of statutory limits. In addition, certain retirees receive defined benefit supplemental pension arrangements.

### Defined Contribution Plans

The Corporation's cost related to the defined contribution arrangement is based upon a percentage of employee earnings. The Corporation's 2011 net benefit cost related to this arrangement was $0.8 million (2010 - $0.8 million).

### Other Post-employment Benefits

The Corporation provides OPEBs to certain of its retired employees including health and dental coverage, provincial medical premiums and life insurance. These benefits are not pre-funded. The most recent actuarial valuation was undertaken as of December 31, 2010.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 18. EMPLOYEE FUTURE BENEFITS (continued)

The financial positions of the Corporation's defined benefit plans and supplemental pension arrangements and OPEBs are as follows:

| | Defined Benefit Pension Plans and Supplemental Pension Arrangements | | Other Post-employment Benefits | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| **Change in fair value of plan assets** | | | | |
| Balance, beginning of year | **$ 105,870** | $ 99,661 | **$ -** | $ - |
| Actual return on plan assets | **1,898** | 5,603 | **-** | - |
| Employer contributions | **5,882** | 4,077 | **499** | 440 |
| Member contributions | **3,257** | 2,819 | **-** | - |
| Benefits paid | **(6,549)** | (6,290) | **(499)** | (440) |
| **Fair value, end of year** | **$ 110,358** | $ 105,870 | **$ -** | $ - |
| **Change in accrued benefit obligation** | | | | |
| Balance, beginning of year | **$ 143,008** | $ 126,659 | **$ 23,641** | $ 17,233 |
| Member contributions | **3,257** | 2,819 | - | - |
| Employer current service cost | **3,767** | 2,656 | **1,065** | 886 |
| Interest cost | **7,140** | 7,265 | **1,206** | 1,104 |
| Benefits paid | **(6,549)** | (6,290) | **(499)** | (440) |
| Actuarial loss (gain) | **4,988** | 9,899 | **(1,211)** | 4,858 |
| **Balance, end of year** | **$ 155,611** | $ 143,008 | **$ 24,202** | $ 23,641 |
| **Composition of accrued benefit asset (liability)** | | | | |
| Fair value of assets | **$ 110,358** | $ 105,870 | **$ -** | $ - |
| Accrued benefit obligation | **155,611** | 143,008 | **24,202** | 23,641 |
| **Funded status – plan deficit** | **(45,253)** | (37,138) | **(24,202)** | (23,641) |
| Contributions after the measurement date | **1,751** | 1,022 | **210** | 198 |
| Unamortized net actuarial loss | **50,389** | 42,417 | **5,906** | 7,535 |
| Unamortized transitional obligation | **746** | 1,637 | **1,423** | 1,787 |
| Unamortized past service cost | **(653)** | (489) | **-** | - |
| **Net accrued benefit asset (liability)** | **$ 6,980** | $ 7,449 | **$ (16,663)** | $ ( 14,121) |
| **Reconciliation of net accrued benefit asset liability** | | | | |
| Accrued benefit asset (liability) at beginning of year | **$ 7,449** | $ 8,917 | **$ (14,121)** | $ (12,001) |
| Net benefit cost | **(7,081)** | (5,423) | **(3,053)** | (2,620) |
| Funding contribution | **6,612** | 3,955 | **511** | 500 |
| **Net accrued benefit asset (liability) at end of year** | **$ 6,980** | $ 7,449 | **$ (16,663)** | $ (14,121) |

Of the net accrued benefit asset of $7.0 million (2010 - $7.4 million), $8.5 million (2010 - $8.7 million) was included in other assets (see note 7) and $1.5 million (2010 - $1.3 million) was included in other liabilities (see note 14).

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 18. EMPLOYEE FUTURE BENEFITS (continued)

The net benefit cost for the Corporation's defined benefit plans and supplemental pension arrangements and OPEBs are as follows:

| | Defined Benefit Pension Plans and Supplemental Pension Arrangements | | Other Post-employment Benefits | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| Employer current service cost | **$ 3,767** | $ 2,656 | **$ 1,065** | $ 886 |
| Interest cost | **7,140** | 7,265 | **1,206** | 1,104 |
| Actual return on assets | **(1,898)** | (5,603) | **-** | - |
| Actuarial loss (gain) on accrued benefit obligation | **4,988** | 9,899 | **(1,211)** | 4,858 |
| Difference between actual and expected return on assets | **(5,629)** | (1,420) | **-** | - |
| Other adjustments to allocate costs: | | | | |
| Net actuarial loss (gain) | **(2,342)** | (8,429) | **1,629** | (4,592) |
| Net transition obligation | **891** | 891 | **364** | 364 |
| Past service cost | **164** | 164 | **-** | - |
| **Total net benefit cost** | **$ 7,081** | $ 5,423 | **$ 3,053** | $ 2,620 |

### Defined Benefit Pension Plan Assets

As at September 30, the assets of the Corporation's defined benefit pension plans were invested as follows:

| | **2011** | 2010 |
|---|---|---|
| Equity securities | **51.5%** | 56.1% |
| Debt securities | **39.5%** | 37.0% |
| Real estate | **7.2%** | 6.2% |
| Cash | **1.8%** | 0.7% |
| | **100.0%** | 100.0% |

### Significant Actuarial Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations and net benefit cost for pensions are as follows:

| | Defined Benefit Pension Plans and Supplemental Pension Arrangements | |
|---|---|---|
| | **2011** | 2010 |
| Liability discount rate (for determining obligations) | **4.50%** | 5.00% |
| Liability discount rate (for determining net benefit cost) | **5.00%** | 5.75% |
| Expected long-term rate of return on plan assets (for determining obligations) | **6.75%** | 7.00% |
| Expected long-term rate of return on plan assets (for determining net benefit cost) | **7.00%** | 7.00% |
| Rate of compensation increase (for determining obligations) | **3.25%** | 3.25% |
| Rate of compensation increase (for determining net benefit cost) | **3.25%** | 3.50% |
| Estimated remaining service life | **10.6 years** | 11.5 years |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 18. EMPLOYEE FUTURE BENEFITS (continued)

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations for OPEBs are as follows:

| | 2011 | 2010 |
|---|---|---|
| Liability discount rate | **4.50%** | 5.00% |
| Health care trend rate: | | |
| Initial rate during first year | **8.00%** | 8.00% |
| Ultimate rate to which the trend rate is assumed to decline | **5.00%** | 5.00% |
| Year in which ultimate rate is reached | **2018** | 2017 |
| Rate of compensation increase | **3.25%** | 3.25% |

The significant actuarial assumptions adopted in measuring the Corporation's net benefit cost for OPEBs are as follows:

| | 2011 | 2010 |
|---|---|---|
| Discount rate | **5.00%** | 5.75% |
| Health care trend rate: | | |
| Initial rate during first year | **8.00%** | 8.00% |
| Ultimate rate to which the trend rate is assumed to decline | **5.00%** | 5.00% |
| Year in which ultimate rate is reached | **2017** | 2016 |
| Rate of compensation increase | **3.25%** | 3.50% |
| Estimated remaining service life | **13.1 years** | 10.5 years |

### Sensitivity to Changes in Assumptions

Changes in the health care trend rates would have the following effects on the Corporation's OPEBs:

| | 2011 | 2010 |
|---|---|---|
| Effect of 1% increase in health care trend rates | | |
| Effect on total of service and interest costs | **$ 179** | $ 179 |
| Effect on OPEB obligation | **1,767** | 1,739 |
| Effect of 1% decrease in health care trend rates | | |
| Effect on total of service and interest costs | **(146)** | (150) |
| Effect on OPEB obligation | **(1,379)** | (1,486) |

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 19. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

| | **2011** | 2010 |
|---|---|---|
| Interest paid | **$ 39,768** | $ 36,336 |
| Income taxes paid | **5,634** | 2,964 |

### Changes in Non-Cash Working Capital

| | **2011** | 2010 |
|---|---|---|
| Changes in working capital: | | |
| Accounts receivable | **$ 6,428** | $ (4,774) |
| Prepaid expenses | **191** | 165 |
| Current regulatory assets and liabilities | **2,428** | 563 |
| Materials and supplies | **28** | 63 |
| Accounts payable and accrued charges | **(13,620)** | 9,602 |
| Income taxes payable | **2,521** | 1,109 |
| | **$ (2,024)** | $ 6,728 |
| Changes in working capital attributable to: | | |
| Operating activities | **7,726** | 754 |
| Investing activities included in capital expenditures - property, plant and equipment | **(9,750)** | 5,974 |
| | **$ (2,024)** | $ 6,728 |

## 20. CAPITAL MANAGEMENT

The objectives of the Corporation to manage capital are to:

- Target a long-term capital structure that includes approximately 40 per cent equity and 60 per cent debt;
- Finance the debt portion of the capital structure primarily with fixed rate, longer term debt in order to match the long term nature of the property, plant and equipment the capital is primarily financing; and
- Maintain investment grade credit ratings to support continued access to cost effective capital.

The Corporation defines its capital as shareholder's equity (consisting of share capital and retained earnings) plus debt (consisting of secured and unsecured debentures gross of deferred financing costs, the WPP mortgage, operating credit facilities, overdraft facility and other short term borrowings).

The Corporation's long term capital structure target of 40 per cent equity and 60 per cent debt is consistent with the deemed capital structure allowed by the BCUC when determining the costs to finance the operations included in customer rates. The Corporation meets its objectives when managing capital by estimating the amount and timing for the issuance of common shares and the payment of dividends, by issuing long term debentures when the Corporation's capital structure includes a relatively high proportion of floating rate debt and by maintaining adequate borrowing capacity on its operating credit facilities.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 20. CAPITAL MANAGEMENT (continued)

The consolidated capital structure of the Corporation is presented in the following table.

| | **December 31, 2011** | | December 31, 2010 | |
|---|---|---|---|---|
| | **$** | **Per cent** | $ | Per cent |
| Total Debt [(1)] | **659,421** | **58.6** | 643,992 | 59.8 |
| Shareholder's Equity | **465,165** | **41.4** | 433,667 | 40.2 |
| **Total** | **1,124,586** | **100.0** | 1,077,659 | 100.0 |

(1) Excludes deferred financing costs of $5.6 million at December 31, 2011 (December 31, 2010 - $6.0 million).

The Corporation has externally imposed capital requirements to which it is subject to that include interest coverage ratios and limitations on the amount of debt that can be incurred relative to equity. The Corporation is in compliance with these externally imposed capital requirements as at December 31, 2011.

## 21. FAIR VALUE MEASUREMENT

### Designation and Valuation of Financial Instruments

The Corporation enters into financial instruments to finance the Corporation's operations in the normal course of business.

The carrying values of the Corporation's financial instruments compared to their fair values are as follows:

| | **2011** | | 2010 | |
|---|---|---|---|---|
| | **Carrying Value** | **Estimated Fair Value** | Carrying Value | Estimated Fair Value |
| **Held for trading** | | | | |
| Cash [(1)] | **$ 4** | **$ 4** | $ 18 | $ 18 |
| **Loans and receivables** | | | | |
| Accounts receivable [(1)(2)] | **39,415** | **39,415** | 45,843 | 45,843 |
| Energy management loans [(1)(2)] | **2,447** | **2,447** | 3,208 | 3,208 |
| **Other financial liabilities** | | | | |
| Accounts payable and accrued charges [(1)(2)] | **41,149** | **41,149** | 54,769 | 54,769 |
| Operating credit and overdraft facilities [(1)(2)] | **17,478** | **17,478** | 1,122 | 1,122 |
| Long-term debt, including current portion [(3)(4)(5)] | **641,943** | **797,541** | 642,870 | 725,224 |

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

(2) Carrying values approximate amortized cost.

(3) Includes secured and unsecured debentures and mortgage obligations for which the carrying value is measured at amortized cost using the effective interest method.

(4) Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at the measurement date or by using quoted market sources.

(5) Excludes deferred financing costs of $5.6 million at December 31, 2011 (December 31, 2010 - $6.0 million).

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 22. FINANCIAL RISK MEASUREMENT

Exposure to credit risk, foreign exchange risk, interest rate risk, and liquidity risk occur in the normal course of the Corporation's operations. The Corporation currently does not enter into derivative financial instruments to reduce exposure to fluctuations in any of the risks impacting the Corporation's operations.

*Credit Risk*

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and cash equivalents, accounts receivable and energy management loans, the Corporation's exposure to credit risk is limited to the carrying value on the balance sheet.

The Corporation extends credit to customers in its role as a regulated electric utility service provider. Credit risk on accounts receivable is managed based on the terms and conditions of the Electric Tariff BCUC No.1 for Service in the West Kootenay and Okanagan Areas. The Corporation manages credit risk for its accounts receivable by requiring customer deposits or credit checks for new customers and by issuing notices, performing disconnections and using third party collection agencies for overdue accounts. The Corporation's credit risk is also mitigated through revenue requirement applications to the BCUC which includes a forecast amount for uncollectible accounts receivable.

The aged analysis of accounts receivable is as follows:

| | **2011** | 2010 |
|---|---|---|
| Not past due | **$ 36,713** | $ 43,354 |
| Past due 0-30 days | **2,052** | 1,895 |
| Past due 31-60 days | **683** | 656 |
| Past due over 60 days | **917** | 996 |
| | **40,365** | 46,901 |
| Less: allowance for doubtful accounts | **950** | 1,058 |
| | **$ 39,415** | $ 45,843 |

*Foreign Exchange Risk*

Foreign exchange risk is the risk that the value of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation realizes all of its sales and a significant majority of its expenses in Canadian dollars and is therefore not exposed to significant foreign exchange rate fluctuations.

*Interest Rate Risk*

Interest rate risk is the risk that the value of a financial instrument will fluctuate due to changes in market interest rates. The Corporation's secured and unsecured debentures bear fixed interest rates, while the Corporation's operating credit facility and overdraft facility are subject to variable interest rates.

A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would increase interest expense for the year ended December 31, 2011 by $0.1 million (2010 - $0.5 million). Under the PBR regulatory framework the Corporation operated within until the end of 2011, any variations in regulated interest expense were flowed through to be paid by or returned to customers in future customer rates. Due to this regulatory mechanism, the Corporation's exposure to interest rate risk on its variable interest rate debt was mitigated.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 22. FINANCIAL RISK MEASUREMENT (continued)

*Liquidity Risk*

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation has secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. FortisBC has authorized bank credit facilities of $160.0 million, comprised of a $150.0 million operating credit facility and a $10.0 million unsecured demand overdraft facility as discussed further in note 12.

Furthermore, the Corporation targets investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2011, the Corporation's credit ratings were as follows:

| Rating Agency | Rating | Debt Rated |
|---|---|---|
| **DBRS** | A (low), Stable Trend | Secured and Unsecured Debentures |
| **Moody's Investors Service** | Baa1, Stable Outlook | Unsecured Debentures |

A downward rating change in the credit ratings of the Corporation on January 1, 2011 would increase interest expense for the year ended December 31, 2011 by $0.1 million (2010 - $0.2 million). Under the PBR regulatory framework that the Corporation operated within to the end of 2011, any variations in regulated interest expense were flowed through to be paid by or returned to customers in future customer rates. Due to this regulatory mechanism, the Corporation's interest expense exposure to a downward change in the credit ratings was mitigated.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities.

| December 31, 2011 | Total | Less than 1 Year | 1 -3 Years | 4-5 Years | Thereafter |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | $ 41,149 | $ 41,149 | $ - | $ - | $ - |
| Interest obligations on long-term debt | 805,945 | 38,854 | 74,474 | 57,994 | 634,623 |
| Operating credit and overdraft facilities | 17,478 | 8,486 | 8,992 | - | - |
| Long-term debt, including current portion(1) | 641,943 | 16,018 | 140,925 | 25,000 | 460,000 |
| | **$ 1,506,515** | **$ 104,507** | **$ 224,391** | **$ 82,994** | **$ 1,094,623** |

| December 31, 2010 | Total | Less than 1 Year | 1 -3 Years | 4-5 Years | Thereafter |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | $ 54,769 | $ 54,769 | $ - | $ - | $ - |
| Interest obligations on long-term debt | 844,791 | 38,896 | 76,062 | 67,858 | 661,975 |
| Operating credit and overdraft facilities | 1,122 | 1,122 | - | - | - |
| Long-term debt, including current portion(1) | 642,870 | 927 | 16,943 | 140,000 | 485,000 |
| | **$ 1,543,552** | **$ 95,714** | **$ 93,005** | **$ 207,858** | **$ 1,146,975** |

(1) Excludes deferred financing costs of $5.6 million at December 31, 2011 (December 31, 2010 - $6.0 million).

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 23. COMMITMENTS AND CONTINGENCIES

In addition to commitments involved with principal payments and maturing issues of debt (see note 12), the BTS Obligation under capital lease (see note 13), ARO expenditures (see note 14) and interest obligations on long-term debt (see note 22), minimum payments for commitments required over the next five years and thereafter are as follows:

| | Power Purchase Obligations | Operating Leases | Pension Funding Obligations | Total |
|---|---|---|---|---|
| 2012 | $ 47,430 | $ 2,100 | $ 6,793 | $ 56,323 |
| 2013 | 45,015 | 1,286 | 6,535 | 52,836 |
| 2014 | 40,257 | 1,361 | - | 41,618 |
| 2015 | 72,837 | 1,344 | - | 74,181 |
| 2016 | 88,155 | 1,344 | - | 89,499 |
| Thereafter | 5,040,941 | 9,071 | - | 5,050,012 |
| | **$ 5,334,635** | **$ 16,506** | **$ 13,328** | **$ 5,364,469** |

### Power Purchase Obligations

The Corporation's power purchase obligations consist of the following:

*Brilliant Power Purchase Agreement (the "BPPA")*

On May 3, 1996 an Order was granted by the BCUC approving the sixty-year BPPA for the output of the Brilliant hydroelectric plant located near Castlegar, BC. The Brilliant plant is owned by the Brilliant Power Corporation ("BPC"), a corporation owned equally by the Columbia Power Corporation and the Columbia Basin Trust. FortisBC operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant, in exchange for the specified take-or-pay amounts of power. The BPPA includes a market related price adjustment after thirty years of the sixty year term.

*BC Hydro Power Purchase Agreement*

The Corporation has a power purchase agreement with BC Hydro which expires in 2013 and provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

*Powerex Capacity Agreement*

During September 2010, FortisBC entered into an agreement to purchase fixed price, winter capacity purchases through to February 2016 from Powerex Corp., a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC brings any new resources, such as capital or contractual projects, on-line prior to the expiry of this agreement, FortisBC may terminate this contract any time after July 1, 2013 with a minimum of three months written notice to Powerex Corp. Additionally, in November 2011, FortisBC entered into a second agreement to purchase fixed price, winter capacity purchases through to March 2012 from Powerex Corp.

## 23. COMMITMENTS AND CONTINGENCIES (continued)

*Waneta Expansion Capacity Agreement (the "WECA")*

FortisBC has entered into an agreement made as of October 1, 2010 to purchase capacity from the Waneta Expansion, a 335 MW hydroelectric generating facility currently under construction adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership, the limited partners of which are FortisBC's ultimate parent, Fortis, which owns a 51 per cent interest, and a wholly-owned subsidiary of each of Columbia Power Corporation and Columbia Basin Trust. It allows FortisBC to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in 2015.The form of the WECA was originally accepted for filing by the BCUC on September 23, 2010 and an executed version of the WECA was submitted to the BCUC on November 18, 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of filing of the executed WECA.

### Operating Leases

FortisBC has entered into operating leases for certain building space and vehicles.

*Building Leases*

Under a sale-leaseback agreement, on September 29, 1993 the Corporation began leasing its Trail, BC office building for a term of thirty years. The terms of the agreement grant the Corporation options to purchase at approximately year twenty and year twenty-eight of the lease term.

During the year ended December 31, 2007, the Corporation entered into an agreement to lease an office building owned by a related company, FortisBC Energy Inc. During the initial five-year term of the lease commencing January 1, 2008, the Corporation will make annual payments of $0.2 million. The Corporation has two options to renew the lease for additional five-year terms.

In addition, the Corporation has entered into leases for various office and warehouse space in the Kelowna area with terms of two to five years.

*Vehicle Leases*

The Corporation has entered into vehicle leases which generally provide for the lessee to pay taxes, maintenance, insurance and certain other operating costs of the leased property, and typically have a lease term of two to five years.

### Pension Funding Obligations

The Corporation sponsors three contributory defined benefit pension plans, one of which is closed to new entrants. Under the terms of these plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations which were dated December 31, 2010.

### Capital Expenditures

As an electric utility, the Corporation is obligated to provide service to customers within its service territory. The Corporation has forecast capital expenditures of approximately $111 million before CIACs for 2012. Additionally, the Corporation has a commitment to purchase fibre optic communication cable for approximately $2.5 million in 2019.

(All tabular amounts are in thousands of Canadian dollars, unless otherwise noted)

## 23. COMMITMENTS AND CONTINGENCIES (continued)

It is expected that capital expenditures in 2012 and beyond will be financed by drawing on the revolving lines of credit, utilizing the proceeds from future debt issues, equity contributions from the parent and from funds generated by operating activities.

### Legal Proceedings

The Province of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a Writ and Statement of Claim against FortisBC dated August 2, 2005. The Province of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private land owners have filed separate Writs and Statements of Claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time, and accordingly no amount has been accrued in the financial statements.

## 24. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent and other related companies under common control. The following transactions were measured at the exchange amount unless otherwise indicated.

| | **2011** | 2010 |
|---|---|---|
| Revenue charged to related parties | **$ 1,922** | $ 1,652 |
| Operating costs charged by related parties | **3,845** | 2,169 |
| Operating costs recovered from related parties | **8,783** | 6,181 |
| Interest revenue on accounts receivable | **28** | 20 |
| Capital costs charged from related parties | **35** | 550 |

The revenues charged represent electricity and services sold to related parties.

The operating costs charged consist of contract and direct labour charges, meter shop charges, rent, natural gas utility charges consumed in operating the Corporation's facilities, corporate governance costs and information technology expenses. In addition, Fortis is authorized to grant certain key employees of FortisBC options to purchase shares of Fortis. For the year ended December 31, 2011, compensation expense relating to stock options of $0.5 million (2010 - $0.5 million) was included in operating costs charged by related parties.

The operating costs recovered consist of labour and materials charges to the Corporation's parent and other related parties.

Included in accounts receivable are amounts due from officers of the Corporation relating to share purchase loans, some of which are non-interest bearing and due within one year from the grant date, and some of which bear interest equal to the amount of the dividends received on the shares and are due within 10 years of the grant date or within one year following cessation of employment, whichever occurs first. Also included in accounts receivable are amounts due from FortisBC Pacific which bear interest at prime. Interest on the related party accounts receivable was recorded in other revenue.

## 24. RELATED PARTY TRANSACTIONS (continued)

Capital costs charged consist of purchasing electrical equipment from a related Fortis subsidiary and the 2010 purchase of land at the carrying amount from the Corporation's parent.

Inter-corporate charges between FortisBC and other related companies under common control are included in accounts receivable (see note 5) and accounts payable and accrued charges (see note 11) and are unsecured and due on demand.

## 25. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with the current period's classifications.

**FortisBC Inc.**
**An indirect subsidiary of Fortis Inc.**

# Annual Information Form
**For the Year Ended December 31, 2011**
**dated March 22, 2012**

# TABLE OF CONTENTS


**FORWARD-LOOKING INFORMATION** .......... 4

**GLOSSARY** .......... 5

**1.0 CORPORATE STRUCTURE** .......... 7

1.1 NAME AND INCORPORATION .......... 7
1.2 INTER-CORPORATE RELATIONSHIPS .......... 7

**2.0 GENERAL DEVELOPMENT OF THE BUSINESS** .......... 7

2.1 THREE-YEAR HISTORY .......... 7
2.2 OUTLOOK .......... 7

**3.0 THE BUSINESS OF FORTISBC INC.** .......... 8

3.1 GENERAL .......... 8
3.2 GENERATION AND POWER SUPPLY .......... 9
3.3 OPERATIONS .......... 11
3.4 OTHER OPERATIONS, ASSETS AND ACTIVITIES .......... 12
3.5 OTHER MATERIAL CORPORATE ISSUES .......... 13

**4.0 REGULATION** .......... 14

4.1 OVERVIEW .......... 14
4.2 REVENUE REQUIREMENT .......... 14
4.3 RECENT REGULATORY DECISIONS AND OUTLOOK .......... 15

**5.0 ENVIRONMENTAL MATTERS** .......... 17

5.1 GENERAL .......... 17
5.2 ENVIRONMENTAL MANAGEMENT SYSTEM .......... 17
5.3 PERMITS, LICENCES AND APPROVALS .......... 17
5.4 ENVIRONMENTAL EXPENDITURES .......... 17
5.5 RELEASES .......... 18
5.6 HAZARDOUS SUBSTANCES .......... 18
5.7 SITE INVESTIGATION AND REMEDIATION .......... 18
5.8 AIR EMISSIONS MANAGEMENT AND POLICY .......... 19
5.9 ASSET RETIREMENT OBLIGATIONS .......... 19
5.10 EMERGENCY PREPAREDNESS AND SAFETY .......... 19
5.11 ELECTRO-MAGNETIC FIELDS .......... 19

**6.0 RISK FACTORS** .......... 20

**7.0 CAPITAL STRUCTURE** .......... 20

7.1 SHARE CAPITAL .......... 20
7.2 DIVIDEND POLICY .......... 20

**8.0 CREDIT RATINGS** .......... 21

**9.0 MARKET FOR SECURITIES** .......... 21

**10.0 DIRECTORS AND OFFICERS** .......... 22

10.1 DIRECTORS .......... 22
10.2 OFFICERS .......... 23
10.3 CONFLICTS OF INTEREST .......... 25

**11.0 EXECUTIVE COMPENSATION** .......... 25

**12.0 SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS** .......... 25

**13.0 INDEBTEDNESS OF EXECUTIVE OFFICERS, DIRECTORS, AND EMPLOYEES** .......... 25

**14.0 INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS** .......... 26

**15.0 MATERIAL CONTRACTS** .......... **26**
**16.0 LEGAL PROCEEDINGS** .......... **27**
**17.0 TRANSFER AGENTS AND REGISTRARS** .......... **27**
**18.0 INTEREST OF EXPERTS** .......... **27**
**19.0 ADDITIONAL INFORMATION** .......... **27**
**SCHEDULE "A" - EXECUTIVE COMPENSATION** .......... **28**
A. COMPENSATION DISCUSSION AND ANALYSIS .......... 28
B. SUMMARY COMPENSATION TABLE .......... 35
C. INCENTIVE PLAN AWARDS .......... 36
D. PENSION PLAN BENEFITS .......... 37
E. TERMINATION AND CHANGE OF CONTROL BENEFITS .......... 38
F. DIRECTOR COMPENSATION .......... 39

*All figures are expressed in Canadian dollars unless otherwise noted.*

*Except as otherwise stated, the information in this Annual Information Form is given as of December 31, 2011.*

## FORWARD-LOOKING INFORMATION

Certain statements contained in this Annual Information Form contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the 2011 Annual Information Form and the information incorporated herein by reference includes, but is not limited to, statements regarding: the Corporation's expected level of capital expenditures; expectations regarding power output in the event that the CPA is terminated; expectations under take-or-pay contracts; expectations of cost of compliance with environmental laws; and, expectations regarding the cost of alternative energy supply compared to the Corporation's regulated wholesale and industrial rates.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; the expected impact of the transition to new accounting standards including US generally accepted accounting principles (US GAAP); the ability to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2014; absence of equipment breakdown; absence of environmental damage; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; the First Nations' settlement process does not adversely affect the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain skilled workforces; absence of information technology infrastructure failure; no significant decline in interest rates; continued electricity demand; the ability to arrange sufficient and cost effective financing; no material adverse ratings actions by credit rating agencies; that counterparties do not default on power supply contracts; no weather related demand loss; and, climate change does not reduce water flows.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; transition to new accounting standards risk; equipment breakdown, operating and maintenance risk; environmental matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving First Nations; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; interest rate risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competiveness and commodity price risk; power supply contracts risk; weather related demand loss risk; climate change risk; and, other risks described in this Annual Information Form. For additional information with respect to these risk factors, reference should be made to the section entitled "Risk Factors" in this Annual Information Form, the section entitled "Business Risk Management" in the Corporation's Management Discussion & Analysis for the year ended December 31, 2011 and the other continuous disclosure materials filed from time to time on SEDAR at www.sedar.com, and which are incorporated herein by reference.

All forward-looking information in this Annual Information Form and the information incorporated herein by reference is qualified in its entirety by this cautionary statement and, except as may be required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

## GLOSSARY

Except as otherwise defined, or unless the context otherwise requires, the following terms have the meanings set forth below.

**“ARO”** means asset retirement obligation;

**“BC Hydro”** means British Columbia Hydro and Power Authority, a British Columbia Crown corporation and electric utility serving the majority of British Columbia residents;

**“BC Hydro PPA”** means the 200 MW power purchase agreement between the Corporation and BC Hydro terminating in 2013;

**“BCUC” or “Commission”** means the British Columbia Utilities Commission;

**“Board”** means the Board of Directors of FBC;

**“Brilliant Plant”** means the 149 MW hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation;

**“Brilliant PPA”** means the 149 MW power purchase agreement between the Corporation and Brilliant Power Corporation terminating in 2056;

**“Canal Plant”** means the Kootenay Canal Plant, a hydroelectric generating plant on the Kootenay River system owned by BC Hydro;

**“CBT”** means Columbia Basin Trust;

**“COPE”** means Canadian Office and Professional Employees Union Local 378;

**“Corporation”** or **“FBC”** means FortisBC Inc.;

**“CPA”** means the amended and restated Canal Plant Agreement made as of July 1, 2005 among BC Hydro, the Corporation, Teck Comino Metals Ltd. (now known as Teck Metals Ltd.), Brilliant Power Corporation, and Brilliant Expansion Corporation;

**“CPC”** means Columbia Power Corporation, a British Columbia Crown corporation;

**“CPI”** means the British Columbia Consumer Price Index;

**“DBRS”** means DBRS Limited;

**“Entitlement”** means a generating facility’s fixed annual entitlement of capacity and energy under the CPA;

**“Entitlement Parties”** means, collectively, Brilliant Power Corporation, Brilliant Expansion Power Corporation, Teck Cominco Metals Ltd. (now known as Teck Metals Ltd.) and FBC;

**“FEI”** means FortisBC Energy Inc. (formerly Terasen Gas Inc.);

**“FHI”** means FortisBC Holdings Inc.(formerly Terasen Inc.);

**“Fortis”** means Fortis Inc.;

**“FortisBC Pacific”** means FortisBC Pacific Holdings Inc. (formerly Fortis Pacific Holdings Inc.);

**“GWh”** means a gigawatt hour, which is a measure of energy that is equal to 1,000,000,000 watts used over a one-hour period;

**“IBEW”** means International Brotherhood of Electrical Workers Union, Local 213;

**“KWh”** means a kilowatt hour, which is a measure of energy that is equal to 1,000 watts used over a one-hour period;

**“Moody’s”** means Moody’s Investors Service, Inc.;

**“MW”** means a megawatt, which is a measure for power that is equal to 1,000,000 watts;

**“MWh”** means a megawatt hour, which is a measure of energy that is equal to 1,000,000 watts used over a one-hour period;

**“PBR”** means the performance-based rate setting methodology for regulation of public utilities;

**“PCBs”** means polychlorinated biphenyls;

“**PIF”** means productivity improvement factor;

**“Rate Base Assets”** means all generation, transmission, distribution and other utility assets that are used or required to be used to provide service to utility customers, which are included in the calculation of the Corporation’s revenue requirement for the applicable year and are subject to a regulated rate of return;

**“ROE”** means return on deemed equity, as approved by the BCUC;

**“UCA” or the “Act”** means the *Utilities Commission Act* (British Columbia), as amended**;**

**“Walden Power Plant”** means the 16 MW hydroelectric generating plant owned by the Walden Power Partnership;

**“WECA”** means the capacity purchase agreement between Waneta Expansion Limited Partnership and FBC made as of October 1, 2010.

## 1.0 CORPORATE STRUCTURE

### 1.1 NAME AND INCORPORATION

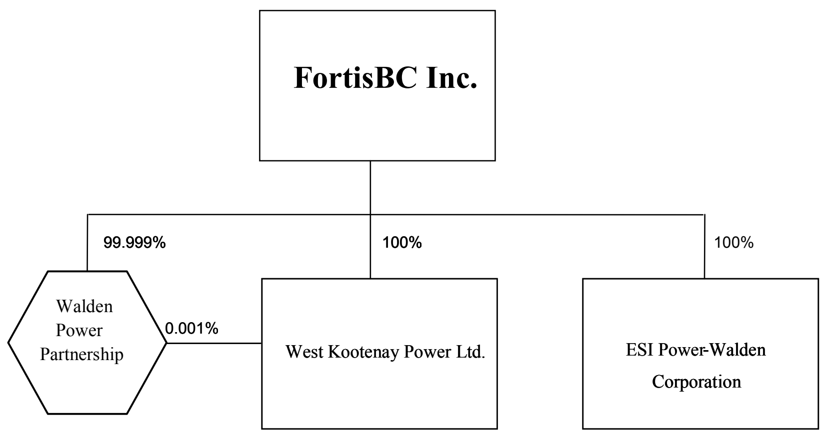
FBC was incorporated as West Kootenay Power and Light Corporation, Limited pursuant to the *West Kootenay Power and Light Corporation, Limited, Act 1897* (British Columbia), as amended. The Corporation's name was changed to "West Kootenay Power Ltd." on September 1, 1988, to "UtiliCorp Networks Canada (British Columbia) Ltd." on October 22, 2001, to "Aquila Networks Canada (British Columbia) Ltd." on May 31, 2002 and to "FortisBC Inc." on June 1, 2004.

FBC's head office is located at Suite 100, 1975 Springfield Road, Kelowna, British Columbia V1Y 7V7 and registered office is located at 2500 – 700 West Georgia Street, Vancouver, British Columbia V7Y 1B3.

### 1.2 INTER-CORPORATE RELATIONSHIPS

The Corporation is an indirect, wholly-owned subsidiary of Fortis, a diversified, international distribution utility holding corporation having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

FBC has two corporate subsidiaries and is a partner in the Walden Power Partnership along with West Kootenay Power Ltd., as set out in the chart below. All of the subsidiaries are organized pursuant to the laws of the Province of British Columbia. The percentages indicated in the chart below represent percentage ownership of voting shares or partnership interest, as applicable.




## 2.0 GENERAL DEVELOPMENT OF THE BUSINESS

### 2.1 THREE-YEAR HISTORY

Over the past three years the Corporation's Rate Base Assets have grown by approximately 33 per cent. This growth reflects the Corporation's capital expenditures necessary to ensure the ability to provide service, public and employee safety and reliability of supply of electricity to the Corporation's growing customer base.

### 2.2 OUTLOOK

Anticipated capital expenditures by the Corporation for 2012, before customer contributions in aid of construction are expected to be approximately $111 million. These capital expenditures are subject to BCUC approval. Planned capital expenditures are based on detailed forecasts of energy demand, weather and cost of labour and materials, as well as other factors including economic conditions, which could change and cause actual expenditures to differ from forecasts.

# 3.0 THE BUSINESS OF FORTISBC INC.

## 3.1 GENERAL

FBC is an integrated, regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of British Columbia. The Corporation has been in continuous operation since 1897.

As at December 31, 2011 FBC served, directly and indirectly, a diverse base of approximately 162,000 customers. Customers are comprised of residential, commercial, wholesale and industrial consumers of electricity located in the cities and rural regions of the southern interior of British Columbia. The majority of FBC's customers are located in urban centres. In 2011, the Corporation sold 3,143 GWh of electricity to its customers, 896 GWh of which was purchased by FBC's seven wholesale customers. The Corporation had a peak demand of 669 MW in 2011, 77 MW lower than the historical peak demand of 746 MW.

The Corporation's regulated generation assets consist of four hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and an annual gross energy entitlement of approximately 1,591 GWh. FBC meets the remainder of its customers' energy and capacity requirements through a portfolio of long-term and short-term power purchase contracts the majority of which have been accepted by the BCUC and the costs of which are flowed through to customers. The Corporation's regulated transmission and distribution assets consist of approximately 7,000 kilometres of transmission and distribution power lines and 65 substations. With the exception of BC Hydro, FBC is the only integrated, regulated electric utility operating in British Columbia. FBC also conducts a small amount of other activities relating primarily to the operation and management of third-party owned hydroelectric generation, transmission and distribution systems located within the FBC service area, as well as the operation of the unregulated Walden Power Plant.

The following map outlines the Corporation's service area:


FBC operates in the southern interior of British Columbia serving approximately 113,000 direct customers in communities including Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland. In addition, FBC indirectly serves approximately 49,000 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Kelowna, Grand Forks and Nelson, as well as to BC Hydro at two points. The service territory is primarily residential but also contains key industries served by FBC including lumber, pulp and paper, mining, agriculture and manufacturing.

The following chart compares 2011 and 2010 regulated revenue, electricity sales, and number of customers by customer class:

| | Electricity Revenue (1) | | | | Electricity Sales (1) | | | | Customers (3) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | | 2010 | | 2011 | | 2010 | | 2011 | | 2010 | |
| | $ millions | % | $ millions | % | GWh | % | GWh | % | # | % | # | % |
| Residential Service | 129.4 | 46.7 | 114.3 | 46.3 | 1,260 | 40.1 | 1,224 | 40.2 | 98,795 | 87.2 | 97,883 | 87.0 |
| Commercial(2) | 67.4 | 24.3 | 64.6 | 26.2 | 705 | 22.4 | 707 | 23.2 | 14,420 | 12.8 | 14,324 | 13.0 |
| Wholesale | 58.5 | 21.1 | 51.8 | 21.0 | 896 | 28.5 | 881 | 28.9 | 7 | 0.0 | 7 | 0.0 |
| Industrial | 21.8 | 7.9 | 16.1 | 6.5 | 282 | 9.0 | 234 | 7.7 | 39 | 0.0 | 36 | 0.0 |
| **Total** | **277.1** | **100** | **246.8** | **100** | **3,143** | **100** | **3,046** | **100** | **113,261** | **100** | **112,250** | **100** |

Notes:

1. Electricity revenue and electricity sales reflect regulated amounts only. Including electricity sales from the Corporation's unregulated business, total electricity sales were 3,183 GWh and 3,082 GWh for the years ended December 31, 2011 and 2010 respectively. Including electricity revenue from the Corporation's unregulated business, total electricity revenue was $279.4 million and $248.8 million for the years ended December 31, 2011 and 2010 respectively.
2. Commercial includes street lights and irrigation.
3. Direct customers.

## 3.2 GENERATION AND POWER SUPPLY

FBC meets the electricity supply requirements of its customers through a mix of owned-generation and short-term and long-term power purchase contracts. The Corporation owns four regulated hydroelectric generating plants with an aggregate capacity of 223 MW, which provide approximately 45 per cent of the energy and 30 per cent of the peak capacity needs of FBC. The four hydroelectric generation plants are located on the Kootenay River and contain fifteen separate generating units. Generation assets represent approximately 16 per cent of the Corporation's Rate Base Assets. Under the CPA, as described below, these generating facilities are dispatched by BC Hydro in exchange for Entitlement. However, the generating units are required to be maintained and available for dispatch. Since 1998, eleven of fifteen FBC hydroelectric generation units have been subject to a life extension and upgrade program which substantially concluded in 2011.

### (a) Canal Plant Agreement

FBC's four hydroelectric generating plants are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants (having a combined capacity of approximately 1,600 MW and all located in relatively close proximity to each other) to coordinate the operation and dispatch of their generating plants. The plants and their respective capacity and owners are:

| Plant | Capacity MW) | Owners |
|---|---|---|
| Canal Plant | 580 | BC Hydro |
| Waneta Dam | 256 [1] | BC Hydro |
| Waneta Dam | 237 [1] | Teck Cominco Metals Ltd. (now known as Teck Metals Ltd.) |
| Kootenay River System | 223 | FortisBC |
| Brilliant Dam | 149 | Brilliant Power Corporation |
| Brilliant Expansion | 120 | Brilliant Expansion Power Corporation |

Note:

1. During 2010 BC Hydro acquired a one-third interest in Waneta Dam.

The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows, subject to the 1961 Columbia River Treaty between Canada and the United States, and coordinated operation of storage reservoirs and generating plants, to generate more power from their respective generating plants than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by the seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these plants, the Entitlement Parties are each contractually entitled to their Entitlements, which are based on 50-year historical water flows. The Entitlement Parties receive their Entitlements irrespective of actual water flows to the Entitlement Parties' generating plants.

BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The Entitlement Parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and therefore do not face hydrology variability in generation supply planning.

The Corporation, however, retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of the Corporation's Kootenay river system plants would, with the water and storage authorized under its existing licenses and on a long-term average, be approximately the same power output as the Corporation receives under the CPA. The CPA does not affect the Corporation's ownership of its physical generation assets. The Corporation continues to own and operate its four Kootenay river system generating plants, which are included in the Corporation's Rate Base Assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

**(b) Power Purchase Agreements**

The majority of the Corporation's electricity supply not supplied by its own generating plants is acquired through long-term power purchase contracts consisting of the following:

(i) the Brilliant PPA;

(ii) the BC Hydro PPA; and

(iii) a number of small power purchase contracts with certain independent power producers.

The majority of these power purchase contracts have been accepted by the BCUC and prudently forecast and incurred costs thereunder flow through to customers through electricity rates. Although FBC can currently meet the majority of its customer supply requirements from its own generation and the major power purchase agreements described above, a portion of the customer load during the summer and winter peak demand periods may need to be supplied from the market in the form of short-term power purchases. Costs related to such purchases, provided they are prudently forecast and incurred, are recovered through rates.

***(i) Brilliant Power Purchase Agreement***

The Brilliant Plant is a hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation. The Brilliant Plant is allocated Entitlement energy of 985,000 MWh and capacity of 149 MW pursuant to the CPA. Under the Brilliant PPA, FBC has agreed to purchase from Brilliant Power Corporation, on a long-term basis (a) the Entitlement allocated to the Brilliant Plant and (b) after the expiration of the CPA, the actual electrical output generated by the Brilliant Plant. While the total entitlement is 985,000 MWh, FBC does not purchase the approximately 60,000 MWh of regulated flow upgrade entitlement. The Brilliant PPA uses a take-or-pay contract structure which requires that FBC pay for the Brilliant Plant's Entitlement, irrespective of whether FBC actually takes it. FBC does not foresee any circumstances under which the Corporation would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FBC pays to Brilliant Power Corporation an amount that covers the operation and maintenance costs of the Brilliant Plant and provides a return on capital, including original purchase costs, sustaining capital costs and any life extension investments. During the second 30 years of the Brilliant PPA term (commencing in 2026), an adjustment using a market price mechanism based on the depreciated value of the Brilliant Plant and then-prevailing operating costs will be made to the amounts payable by FBC. The Brilliant PPA provided FBC with approximately 25 per cent of its energy requirements in 2011.

***(ii) Power Purchases from BC Hydro***

FBC is a party to the BC Hydro PPA, which provides the Corporation with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. Energy bought pursuant to the BC Hydro PPA provided approximately 15 per cent of FBC's energy requirements in 2011. The current term of the BC Hydro PPA extends until 2013 and provides FBC with electricity at BCUC approved tariffs for that term. The Corporation and BC Hydro are currently in negotiations regarding the renewal or replacement of the agreement for an additional 20 year term. Since the rates under the BC Hydro PPA are approved by the BCUC and form part of BC Hydro's filed tariff, any rate increases are tied to BC Hydro's regulated rate increases and can be recovered by FBC from its consumers as a normal power purchase expense for which flow-through treatment applies.

***(iii) Small Power Purchase Contracts***

FBC has a number of small power purchase contracts with independent power producers, which collectively provided approximately 1 per cent of the Corporation's energy supply requirements in 2011. The majority of these contracts have been accepted by the BCUC.

***(iv) Spot Market and Contracted Capacity Purchases***

During 2011, the Corporation entered into various arrangements to purchase capacity and energy from the market to meet its peak energy requirements. Certain of these purchases were at prevailing market prices, which were sourced from the United States and British Columbia and are typically linked to the Mid-Columbia trading hub in the U.S. Pacific Northwest. During 2010 the Corporation entered into an agreement to purchase fixed price, winter capacity purchases through to February 2016 to assist in mitigating the risks of market volatility and availability. Spot market purchases provided approximately 14 per cent of the Corporation's energy supply requirements in 2011.

***(v) Waneta Expansion Capacity Agreement***

The Corporation entered into the WECA to purchase capacity from the Waneta Expansion, a 335 MW hydroelectric generating facility currently under construction adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership, the limited partners of which are FBC's ultimate parent corporation, Fortis, which owns a 51 per cent interest, and a wholly-owned subsidiary of each of CPC and CBT. The WECA allows FBC to purchase capacity over 40 years upon completion of the Waneta expansion, which is expected to be in 2015. The form of the WECA was originally accepted for filing by the BCUC on September 23, 2010 and an executed version of the WECA was submitted to the BCUC on November 18, 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of the filing of the executed WECA.

## 3.3 OPERATIONS

### (a) Transmission

FBC's transmission system is a high voltage system that operates at the 230 kV, 161 kV, 138 kV and 63 kV levels while transmitting electricity to customers directly connected to the transmission grid. The transmission system is highly integrated and operates synchronously with the BC Hydro system. It consists of approximately 1,400 kilometres of transmission lines and includes major substations throughout the service territory. FBC has 9 terminal transmission substations, the components of which include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, together with site infrastructures such as buildings and security systems. There are also 4 additional substations with generator step-up transformers associated with the four generating plants. Currently, transmission assets represent approximately 36 per cent of the Corporation's Rate Base Assets. The FBC transmission system is being replaced or upgraded in a number of locations.

**(b) Distribution**

Electricity produced at generating plants is moved across transmission lines to terminal stations and transformers and then distributed at lower voltages to customers. FBC's distribution system is comprised of 52 distribution substations and approximately 5,600 kilometres of overhead and underground distribution lines. Currently, distribution assets represent approximately 36 per cent of the Corporation's Rate Base Assets. The FBC distribution system is being upgraded in a number of locations over several years in order to renew obsolete components at or near the end of their useful life, to establish a standard voltage and to accommodate load growth that has caused load on the existing system to approach design capacity.

**(c) Major Capital Projects**

The Corporation plans and implements programs for sustaining and enhancing its regulated generation, transmission and distribution assets. Capital projects are typically identified as being one of two types: (a) "sustaining", which are directed at adequately maintaining asset condition and modernizing equipment; and (b) "growth" or "expansionary", which are primarily required to accommodate customer and load growth within the FBC service area. Developing the priorities for the transmission and distribution system involves an assessment of both asset condition and maintenance needs and system contingency analysis. The latter involves a modeling and simulation of system impacts following several possible and different system event scenarios.

Anticipated capital expenditures by the Corporation for 2012, before customer contributions in aid of construction are expected to be approximately $111 million. These capital expenditures are subject to BCUC approval. Planned capital expenditures are based on detailed forecasts of energy demand, weather and cost of labour and materials, as well as other factors including economic conditions, which could change and cause actual expenditures to differ from forecasts. The capital expenditures are necessary to ensure the ability to provide service, public and employee safety and reliability of supply to the Corporation's growing customer base.

## 3.4 OTHER OPERATIONS, ASSETS AND ACTIVITIES

**(a) Other Operations**

FBC carries out monitoring, control and real-time management of its generation, transmission and distribution facilities through its control centre in Warfield, British Columbia. The control centre coordinates with BC Hydro to ensure that appropriate monitoring and control of transmission equipment is maintained twenty-four hours a day.

**(b) Other Assets**

Other assets of the Corporation include those supporting the ongoing maintenance and operation of the system, such as office and service buildings, transport and work equipment and other office and information technology assets. Other assets represent approximately 12 per cent of the Corporation's Rate Base Assets.

**(c) Other Activities**

FBC's other activities are relatively small in comparison to its regulated electricity operations but provide an opportunity to leverage the utilization of FBC's utility operation, maintenance and management resources under service contracts to third parties. FBC provides certain operations, maintenance and management services relating to the 493 MW Waneta hydroelectric generation plant owned by Teck Cominco Metals Ltd. (now known as Teck Metals Ltd.) and BC Hydro, the Brilliant Plant and the 120 MW Brilliant Expansion Plant owned by CPC and CBT through Brilliant Expansion Power Corporation.

FortisBC Pacific, the direct parent of the Corporation, provides services of a similar nature to various third parties such as the City of Kelowna, CPC and CBT. FBC provides staff and material resources to FortisBC Pacific in order for it to carry out the services required under the contracts and charges FortisBC Pacific its cost plus a mark-up as compensation.

In addition, FBC owns the Walden Power Partnership, an independent power producer which owns and operates an unregulated 16 MW run-of-the-river, hydroelectric power plant near Lillooet, British Columbia. The Walden Power Plant commenced operating in 1992 and sells 100 per cent of its output to BC Hydro under a long-term contract expiring in 2013. The Walden Power Plant is financed by a mortgage on the Walden Power Plant.

## 3.5 OTHER MATERIAL CORPORATE ISSUES

### (a) Insurance

The Corporation, through Fortis, maintains insurance coverage including liability, all risk property, boiler and machinery, and directors' and officers' liability insurance for the benefit of the Corporation. The Corporation self-insures against the risk of damage to transmission and distribution poles, wires and related equipment. FBC also maintains insurance coverage that is required by provincial statute, which covers automobile liability, firefighting expense and non-owned aircraft liability. Management believes that the coverage, amounts and terms of the Corporation's insurance agreements are consistent with industry practices.

### (b) Employees

The Corporation employed approximately 528 full-time equivalent employees as at December 31, 2011.

The collective agreement between the Corporation and IBEW expires on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation, transmission and distribution.

The collective agreement between the Corporation and COPE expired January 31, 2011. During 2011, discussions between the parties focused on the renegotiation of the FBC COPE agreement. An agreement has been reached with regard to certain customer service employees. Discussions continue with regard to the remaining FBC COPE bargaining unit.

### (c) Specialized Skills and Knowledge

The skills and knowledge needed to operate and maintain electrical generation, transmission and distribution systems are key to the Corporation's success. These skills are currently available, and the Corporation has placed considerable focus in succession planning on ensuring that these skills are preserved as the Corporation's workforce ages and retires.

### (d) Intellectual Property

Fortis owns the trademark "FortisBC", which it has licensed the Corporation to use. FBC owns the trademark "PowerSense", which has been used in the promotion by the Corporation of energy efficiency and energy awareness programs.

### (e) Real Property

Certain of the Corporation's transmission and distribution facilities cross over land that is owned by the governments of Canada or British Columbia. The Corporation believes it has obtained appropriate access rights from the relevant governments through Crown leases, statutory rights of way, land use permits, licences of occupation and low voltage permits. Where transmission or distribution lines extend over waterways, various provincial and federal government bodies must approve the installation of those lines. Agreements and permits in this respect have been obtained from the appropriate government body.

The Corporation's transmission and distribution lines at times also cross over or run parallel to lands owned by various railway companies. In these circumstances, appropriate access rights, generally referred to as crossing agreements, have been obtained from the relevant railway company. Some of the Corporation's transmission and distribution lines are located on lands owned by other persons, including local governments, corporations, First Nations and individuals. The Corporation believes it has obtained or is in the process of obtaining the rights to use these lands through working with the property owner to come to an agreement (such as statutory rights of way) permitting land usage.

If the Corporation becomes aware of a situation in which it has not acquired the requisite usage rights, it will attempt to come to an agreement to secure usage rights with the landowner. The Corporation has the power to expropriate land if necessary.

**(f) Seasonality**

FBC's peak demand for electricity occurs in the winter months due to increased customer load as a result of cooler weather in the winter months, and therefore FBC normally generates higher earnings in the first quarter of the fiscal year.

**(g) Competition**

British Columbia's traditional regulatory model does not support retail competition for customers, which would give customers the right to purchase electricity from suppliers other than the utility to which they are directly connected. FBC has a form of retail access for its wholesale and industrial customers supplied at transmission voltage. This retail access has not led to a loss of any of FBC's wholesale or industrial customers for two reasons. First, those customers could be required to reimburse FBC for any stranded costs created as a result of their departure. Second, currently available alternative sources of supply are, or are expected to be, more expensive than FBC's regulated wholesale and industrial rates.

## 4.0 REGULATION

### 4.1 OVERVIEW

Public utilities in British Columbia, such as FBC, are subject to the regulatory jurisdiction of the BCUC. The UCA is the legislation that defines the scope of the BCUC's jurisdiction regarding the regulation of public utilities and the responsibilities of those public utilities. The BCUC's primary responsibility is to establish just and reasonable utility rates, which include an opportunity for the utilities to earn a fair return on the investments they have already made and will make in the future to provide customers with safe and reliable service.

### 4.2 REVENUE REQUIREMENT

The rate setting process generally has three essential elements: revenue requirements, allocation of cost of service, and rate design.

The utility's revenue requirements represent the total revenues that are necessary for the utility to recover prudent costs for providing the utility services, to recover prudent investment, and to earn a fair return on its investment. The cost of service includes energy costs, operating and maintenance expenses, depreciation expenses, taxes, and the costs of financing rate base, including a return on equity. Rate base is the book value of utility plant in service (plant less accumulated depreciation and customer contributions in aid of construction) and utility deferred charges, plus an allowance for working capital invested in the business, and is the investment base to which a rate of return is applied to arrive at the revenue requirements. The return on rate base is established by determining the cost of individual components of the capital structure, including equity, and weighting such costs to determine an aggregate return on rate base. Both the capital structure and rate of return on equity are determined by the BCUC, as further discussed below.

The BCUC usually uses a future test year methodology in establishing the revenue requirements for a utility. Pursuant to this method, the Corporation forecasts the amount of electricity that will be delivered during normal weather, together with all of the other costs of providing service (including the return on rate base) that FBC forecasts to incur in the test year(s). Variances between the forecast costs and the actual costs incurred, and variances in the actual amount of electricity delivered from what has been forecast, normally result in variances in FBC's return, except for variances that are captured by deferral accounts for future recovery or refund.

Until the end of 2011, FBC's revenue requirements were determined in accordance with a PBR plan negotiated with its major customer groups in 2006. The PBR plan established a process for determining FBC's annual revenue requirements rates and provided for incentive mechanisms for improving operating efficiencies along with a benefits sharing arrangement with its customers. The PBR plan included thirteen service quality measures designed to ensure that FBC maintained adequate service levels and provided for a 50/50 sharing mechanism of earnings within a range of 2 per cent above or below the allowed return on equity.

FBC employs deferral accounts to address certain uncontrollable or non-routine items and to match costs incurred to the periods that they benefit. In addition to a continuation of deferral accounts and flow through treatments that existed under the PBR period, the 2012-2013 Revenue Requirements Application requests deferral accounts and flow-through treatment for variances from the forecast used to set rates for electricity revenue, power purchase costs and certain other costs.

After revenue requirements have been established, costs are allocated among different classes of electricity users/customers and rates are designed to reflect of the cost of providing services to each rate class. Before any rate can be put into effect, it must be filed with and approved by the BCUC. In British Columbia, the regulatory process for determining the revenue requirements and setting the rates is undertaken with input from customer representatives, other public groups or private individuals.

## 4.3 RECENT REGULATORY DECISIONS AND OUTLOOK

Important regulatory information pertaining to decisions made by the BCUC with respect to FBC, is summarized in the following table, followed by discussions on certain regulatory decisions or pending proceedings that affect FBC's operation currently and in the near future.

| ($ millions) | 2012[1] | 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|
| Rate Base Assets | $1,146 | $ 1,093 | $ 975 | $ 908 | $ 823 | $ 747 |
| Deemed common equity component of total capital structure | 40.00% | 40.00% | 40.00% | 40.00% | 40.00% | 40.00% |
| Allowed rate of return on common equity | 9.90% | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% |

Note:

1. The figures for 2012 are on a forecast basis only and are based on the most recent filings with the BCUC.

### Cost of Capital and ROE

The BCUC previously used an annual automatic adjustment mechanism to determine the allowed return on common equity for a low-risk benchmark utility. The adjustment formula was based on long-term Canada bond yields.

Following determination of the rate of return on common equity for the low-risk benchmark utility, an additional risk premium particular to each utility relative to the low-risk benchmark was also incorporated. For FBC, a risk premium of 0.40 per cent was applied to the benchmark low-risk utility ROE.

On December 16, 2009, the BCUC ordered that the automatic adjustment mechanism be discontinued, but that FEI would continue to serve as the benchmark utility, with an approved ROE of 9.5 per cent. FBC's ROE of 9.9 per cent effective January 1, 2010 continues to recognize a risk premium of 0.40 per cent. The BCUC also directed FEI to complete a study by December 31, 2010 of possible alternative formulae to re-establish an automatic adjustment mechanism. This study was filed with the BCUC in December of 2010 and did not propose to adopt an automatic adjustment mechanism for ROE at that time.

In November 2011, the BCUC issued notice to the public utilities subject to its regulation that it will initiate a cost of capital proceeding in early 2012 to consider three issues: (1) setting the appropriate cost of capital for a benchmark low-risk utility; (2) establishing a return on equity automatic adjustment mechanism; and (3) establishing a deemed capital structure and deemed cost of capital methodology particularly for those utilities without third-party debt.

**Revenue Requirement and Rates**

On April 19, 2006, FBC and a group of interveners concluded negotiations on the Corporation's 2006 Revenue Requirements application. In addition to an agreement on the increase to customer rates required for 2006, the settlement agreement set 2006 as the base year for a PBR term from 2006 to 2008, with an option to extend the term to 2009. The settlement agreement was approved by the BCUC on May 23, 2006. The significant terms of the PBR agreement negotiated in 2006 were as follows:

- annual gross operating and maintenance expenses before capitalized overhead were set by formula incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 2 per cent in 2007, 2 per cent in 2008 and, if applicable, 3 per cent in 2009;
- annual capitalized overhead was set at 20 per cent of the BCUC approved gross operating and maintenance expense;
- other components of revenue requirements were to be forecast annually; and
- a 2 per cent collar around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, were to be shared equally between customers and the shareholder. If the variance exceeded the 2 per cent collar, the excess would be placed in a deferral account for review and disposition during the next rate setting process. The Corporation's portion of the incentive was subject to the Corporation meeting certain performance standards and BCUC approval.

As part of the approval of 2009 Revenue Requirements on December 11, 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement were consistent with the May 23, 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead were set by formula incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess would be added to the PIF which effectively capped the CPI at 3 per cent.

**2011 Revenue Requirement and Rates**

On December 23, 2010 the BCUC approved a 6.6 per cent rate increase effective January 1, 2011, which included the impacts of the 2011 Revenue Requirements negotiated settlement agreement and the 2011 Capital Expenditure Plan which was approved on December 17, 2010. The 6.6 per cent rate increase was primarily the result of the Corporation's ongoing investment in infrastructure and the higher cost of capital. Rates for 2011 reflected an allowed ROE of 9.9 per cent and an equity component of capital structure at 40 per cent.

On May 19, 2011, the BCUC approved a further 1.4 per cent interim refundable rate increase effective June 1, 2011. This rate increase became permanent in an order of the BCUC dated November 30, 2011. This increase was due to increased power purchase costs charged by BC Hydro to the Corporation relating to its BCUC approved interim and refundable rate increase, effective April 1, 2011.

**2012-2013 Revenue Requirement and Rates**

On June 30, 2011 FBC filed its 2012-2013 Revenue Requirements Application, which is based on cost of service principles. The Application was subsequently updated on November 4, 2011. The Application seeks approval of general rate increases of 1.5 per cent effective January 1, 2012 and 6.5 per cent effective January 1, 2013, mainly as a result of the ongoing investment in infrastructure, the higher cost of capital and increased power purchase costs. On November 30, 2011 the BCUC approved an interim refundable rate increase of 1.5 per cent effective January 1, 2012. Requested rates for 2012 and 2013 reflect an allowed ROE of 9.9 per cent and an equity component of capital structure at 40 per cent. As discussed above, the BCUC has issued a notice to initiate a cost of capital proceeding in early 2012, which may affect FBC's earnings.

The BCUC ordered an oral public hearing in March 2012 to review the 2012-2013 Revenue Requirements Application.

**Mandatory Reliability Standards**

In June 2009, the BCUC adopted 103 reliability standards for planning and operating the North American bulk power system. The adopted standards apply to FBC. Failure to comply with these standards could result in the Corporation being liable for a statutory penalty.

## 5.0 ENVIRONMENTAL MATTERS

### 5.1 GENERAL

Canadian federal, provincial and municipal governments share jurisdiction over matters affecting safety and the environment. As a result, the Corporation is subject to provincial occupational health and safety legislation as well as federal, provincial and municipal regulations relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, disposal and release of hazardous and non-hazardous substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after commencement.

### 5.2 ENVIRONMENTAL MANAGEMENT SYSTEM

The environmental risks associated with the Corporation's activities and operations are managed under the framework of an environmental management system (EMS). FBC has an EMS in place to manage the impact of its activities on the environment and the design of the EMS is consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems.

The Corporation's EMS includes an environmental policy, a summary of the environmental risks associated with the Corporation's business and operations, a summary of relevant environmental legislation, and an internal reporting process. The EMS also includes environmental training requirements for employees and contractors and environmental guidelines that serve to minimize the environmental impacts of FBC operations and ensure compliance with applicable environmental legislation. FBC has external audits of its EMS conducted on a regular cycle to ensure continued compliance with ISO 14001 standards.

### 5.3 PERMITS, LICENCES AND APPROVALS

Various federal and provincial statutes require the Corporation to obtain and maintain specific permits, licences and approvals in the course of its operations. Pursuant to the Water Act (British Columbia), water rental rates apply to the use of water for power generation. Water rental rates in British Columbia are levied on the basis of both total station capacity and on total station generation. The Corporation is able to recover water rental costs through rates.

### 5.4 ENVIRONMENTAL EXPENDITURES

The Corporation incurred environmental compliance and environmental management system related capital expenditures in connection with capital projects and in connection with ongoing operation and maintenance activities that are not reasonably quantifiable. The Corporation's cost of compliance with environmental laws and regulations did not have a material effect on the operating costs, capital expenditures, earnings or competitive position of the Corporation in 2011 and, based on current laws, facts and circumstances, is not expected to have a material effect on such matters in the future. Operating and capital costs associated with complying with environmental laws and regulations are generally recoverable by the Corporation through rates.

## 5.5 RELEASES

Federal, provincial and municipal environmental legislation regulate the release of substances into the environment through the regulation of discharges that have an adverse effect or a potentially adverse effect on the environment. FBC believes that the potential for spills, and resulting enforcement actions under existing environmental legislation, is reduced through the implementation of spill prevention, material handling, emergency response programs and spill response guidelines in conjunction with appropriate training. The potential for an adverse effect resulting from a spill is further reduced by the Corporation through the tracking of all incidents and potential incidents in an incident reporting database in order to facilitate continual learning and improvement.

## 5.6 HAZARDOUS SUBSTANCES

The Corporation manages hazardous substances used in its operations such as PCBs and herbicides. The Corporation has environmental management programs in place to deal with the hazardous substances including programs to deal with PCBs and herbicides:

(a) *PCBs* - Current management plans for PCBs focus on the identification, safe handling, transportation, storage and ultimate disposal of PCB containing equipment. As equipment becomes obsolete and is taken out of service, FBC disposes of it in an environmentally sound manner and in compliance with applicable laws. Federal PCB regulations specify deadlines for the elimination of PCB containing equipment. With the exception of pole-top transformers and their auxiliary equipment, PCB containing equipment having levels of PCBs greater than 500 ppm or those with PCB levels between 50 ppm and 500 ppm located in sensitive areas were removed from service by the end of 2009. FBC believes it is compliant with the PCB regulation for all primary equipment. For certain substation auxiliary equipment FBC has been granted an extension to the Federal PCB regulation deadline to December 31, 2014. All other electrical equipment with PCB levels greater than 50 ppm must be removed from service by December 31, 2025. FBC intends to take the necessary steps to meet these compliance deadlines and has applied to the BCUC to recover the associated costs through rates.

(b) *Herbicides* - The Corporation uses herbicides primarily for the control of incompatible vegetation on rights-of-way, along transmission and distribution lines and on station sites. The Corporation uses an integrated approach toward vegetation management using manual and mechanical cutting, natural competition from compatible vegetation, together with the selective use of herbicides. Patrols occur to monitor vegetation growth and assess appropriate maintenance activities. Site-specific conditions, including tree species, tree density, height, terrain, prevailing wind directions, and adjacent land uses, are considered by the Corporation in determining the appropriate overall vegetation management plan. Herbicides are applied in accordance with applicable federal and provincial legislation, which governs application, notification and reporting.

In addition, some facilities and products used in operational activities contain substances that are designated for special treatment under occupational health and safety legislation, such as asbestos, lead and mercury. The Corporation has exposure control plans in place to address situations when these kinds of substances are encountered or utilized.

## 5.7 SITE INVESTIGATION AND REMEDIATION

Spills and leaks of substances may occur in the normal course of the Corporation's operations and may result in future clean-up costs being incurred in connection with these releases. The Corporation has from time to time, investigated sites for potential contamination and remediated sites where appropriate. It is possible that remediation costs could be incurred in future due to contamination at sites and the Corporation expects that costs incurred for site remediation would be recovered through rates.

## 5.8 AIR EMISSIONS MANAGEMENT AND POLICY

British Columbia government policy direction with respect to air emissions management regulation continues to unfold, but it remains to be determined to what extent a greenhouse gas emissions cap will impact the Corporation. The cap and trade program was expected to begin on January 1, 2012 but the government has delayed the development of this regulatory initiative. The specific details regarding the cap and trade program will be defined in regulation once it is developed. If implemented the cap and trade program is expected to have a declining cap on emissions that all covered facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for releases over the capped amount. In 2012 the Corporation will begin reporting its greenhouse gas emissions for electricity imports pursuant to the provincial greenhouse gas reporting regulation.

## 5.9 ASSET RETIREMENT OBLIGATIONS

During 2010 the Corporation obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of PCB contaminated oil, as previously described in Section 5.6(a), from certain of its electrical equipment. As such, the Corporation has recorded an ARO of $3.9 million as at December 31, 2011 and $3.2 million as at December 31, 2010. The determination of the ARO depends upon management's best estimates relating to factors such as timing, amount and nature of future cash flows necessary to discharge the legal obligation and comply with existing legislation or regulations, as well as the use of a credit-adjusted risk-free rate for measurement purposes. There are uncertainties in estimating future asset retirement costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. It is possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Corporation's current assumptions. In addition, in order to remove certain PCB-contaminated oil, the ability to take maintenance outages in critical facilities may impact the timing of expenditures. The ARO may change from period to period because of the changes in the estimation of these uncertainties.

Excluding the ARO pertaining to PCBs, the nature, amount and timing of costs associated with land and other environmental remediation and/or removal of assets, cannot be reasonably estimated due to the nature of their operation; and applicable licences, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licences, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

## 5.10 EMERGENCY PREPAREDNESS AND SAFETY

FBC has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations.

The Corporation is committed to monitoring and assessing its safety management system regularly. FBC incorporates safety performance measures into its employee compensation system, sets challenge levels and objectives for performance, and conducts safety and environmental audits regularly.

## 5.11 ELECTRO-MAGNETIC FIELDS

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and within every building that has electrical service. Scientists and public health experts in North America and abroad are studying the possibility that exposure to electro-magnetic fields may cause health problems. FBC understands there is no conclusive evidence of any harm caused by exposure at levels normally found in Canadian living and working environments. Electro-magnetic fields are not currently regulated by the federal or provincial governments and the Corporation is unaware of any plans to regulate electro-magnetic fields. Health Canada confirmed its position in January 2010 that there are no known health risks from power lines.

## 6.0 RISK FACTORS

For more information with respect to risks and uncertainties to which the Corporation is subject, see the section entitled "Business Risk Management" in the Corporation's Management Discussion & Analysis for the year ended December 31, 2011, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

## 7.0 CAPITAL STRUCTURE

FBC's business requires the Corporation to have ongoing access to capital to allow it to build and maintain the electrical systems in its service territory. In order to ensure that this access to capital is maintained and in accordance with BCUC requirements, the Corporation targets a long-term capital structure that includes 40 per cent equity and 60 per cent debt.

## 7.1 SHARE CAPITAL

The Corporation is authorized to issue 500,000,000 common shares with a par value of $100 each and 500,000,000 preferred shares with a par value of $25 each, of which 20,000 shares have been designated as Preferred Shares - Series 1, and 480,000 shares have been designated as Cumulative Redeemable Retractable Preferred Shares - Series 2. The issued and outstanding share capital of FBC as at December 31, 2011 consists of 2,018,510 common shares and no preferred shares. Fortis owns all of the issued common shares through its indirect wholly-owned subsidiary, FortisBC Pacific.

Holders of common shares of the Corporation are entitled to receive dividends as and when declared by the Board, subject to the rights of holders of the preferred shares, and are entitled to one vote per share on all matters to be voted on at all meetings of shareholders except those meetings at which only the holders of shares of another class or of a particular series are entitled to vote. Upon the liquidation, dissolution or winding-up of the Corporation, the holders of common shares are entitled to share rateably in the remaining assets available for distribution, after payment of liabilities and subject to the rights of the holders of the preferred shares. The common shares do not have exchange, conversion, redemption or retraction rights.

Preferred shares may be issued from time to time in one or more series, each series comprising the number of shares, designation, rights and restrictions determined by the Board. Preferred shares are entitled to priority over the common shares with respect to the payment of dividends and distributions of assets in the event of the liquidation, dissolution or winding-up of the Corporation. Except in respect of a meeting of holders of the preferred shares or of a particular series of the preferred shares, or except as may otherwise be provided in the rights attached to any series of preferred shares, holders of the preferred shares will not be entitled to vote at any meetings of shareholders.

## 7.2 DIVIDEND POLICY

The declaration and payment of dividends is at the discretion of the Board and will be influenced by ongoing capital structure management.

The Corporation paid dividends on its common shares of $16.0 million during the year ended December 31, 2011, $15.0 million during the year ended December 31, 2010 and $14.5 million during the year ended December 31, 2009.

Certain of the Corporation's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 75 per cent of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceeds thresholds based on the cumulative net earnings of the Corporation.

## 8.0 CREDIT RATINGS

The following table discloses the Corporation's debenture ratings as at December 31, 2011.

| Credit Ratings | DBRS | Moody's |
|---|---|---|
| Unsecured Debentures | A (low), Stable Trend | Baa1, Stable Outlook |
| Secured Debentures | A (low), Stable Trend | - |

Ratings are not recommendations to purchase, hold, or sell debentures because ratings do not comment as to market price or suitability for a particular investor. The Corporation understands that ratings are based on, among other things, information furnished to the rating agencies by the Corporation and information obtained by the rating agencies from public sources. Ratings may be changed, suspended or withdrawn as a result of changes in, or unavailability of, that information.

Securities issued by FBC are rated by DBRS and Moody's. The ratings assigned to securities issued by FBC are reviewed by these agencies on an ongoing basis. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. DBRS rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. Moody's rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities to C which represents the lowest quality of securities.

According to the Moody's rating system, debt securities rated Baa are considered to be subject to moderate credit risk, are medium grade obligations and as such may possess certain speculative characteristics. Moody's applies numerical modifiers (1, 2 and 3) in each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category.

According to the DBRS rating system, debt securities rated A are of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA related entities. While a respectable rating, entities in the A category are considered to be more susceptible to economic conditions and have greater cyclical tendencies than higher rated companies. Any qualifying negative factors which exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry. "High" or "Low" are used to indicate the relative standing of a credit within a particular rating category. The lack of one of these designations indicates a rating which is essentially in the middle of the category.

## 9.0 MARKET FOR SECURITIES

None of the issued and outstanding shares of the Corporation or any of its debentures are listed on any exchange.

## 10.0 DIRECTORS AND OFFICERS

### 10.1 DIRECTORS

The following table sets forth as at December 31, 2011 the name, province and country of residence of each director of the Corporation, his or her respective position and office with the Corporation, his or her principal occupation during the five preceding years, and the period during which each director has served as a director of the Corporation and when his or her term expires:

| NAME AND RESIDENCE | TERM AS A DIRECTOR [4] | PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS |
|---|---|---|
| Harold G. Calla[1]<br>British Columbia, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Chair of the First Nation Financial Management Board. |
| Beth D. Campbell[2]<br>British Columbia, Canada | Commencing 2005.<br>Term expires at the next annual general meeting. | President, Best in the West Motor Inn Ltd. |
| Brenda Eaton[1]<br>British Columbia, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Board Chair, BC Housing Management Commission. |
| Ida J. Goodreau[2]<br>British Columbia, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Corporate Director; additionally Adjunct Professor, Sauder School of Business, UBC; prior thereto President and CEO of Lifelabs from March 2009 to November 2009; prior thereto President and Chief Executive Officer of Vancouver Coastal Health Authority. |
| H. Stanley Marshall[2][3]<br>Newfoundland and Labrador, Canada | Commencing 2004.<br>Term expires at the next annual general meeting. | President & Chief Executive Officer of Fortis Inc. |
| Roger M. Mayer[1]<br>British Columbia, Canada | Commencing 2006.<br>Term expires at the next annual general meeting. | Vice Chair of the BC Agricultural Land Commission since 2008; and additionally Director of the Okanagan Similkameen Regional District. |
| Harry McWatters[2]<br>British Columbia, Canada | Commencing 2005.<br>Term expires at the next annual general meeting. | President, Vintage Consulting Group since May 2008; additionally President, Sundial Vineyard; prior thereto President & CEO of Sumac Ridge Estate Wine Group. |
| Barry V. Perry[1]<br>Newfoundland and Labrador, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Vice President, Finance and Chief Financial Officer of Fortis Inc. |
| Linda S. Petch[2]<br>British Columbia, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Principal, Linda S. Petch Governance Services |
| David R. Podmore[1]<br>British Columbia, Canada | Commencing 2010.<br>Term expires at the next annual general meeting. | Chairman and Chief Executive Officer, Concert Properties Ltd. since June, 2009; prior thereto President & Chief Executive Officer of Concert Properties Ltd. |
| Karl W. Smith[2]<br>Alberta, Canada | Commencing 2011.<br>Term expires at the next annual general meeting. | President & CEO of FortisAlberta Inc. since May 2007; prior thereto President & CEO of Newfoundland Power Inc. |

| NAME AND RESIDENCE | TERM AS A DIRECTOR (4) | PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS |
|---|---|---|
| John C. Walker<br>British Columbia, Canada | Commencing 2005.<br>Term expires at the next annual general meeting. | President & CEO of the Corporation and additionally President & CEO of FortisBC Energy Inc. and FortisBC Holdings Inc. since July 2010. |

Notes:

1. Member of the Audit and Risk Committee.
2. Member of the Governance Committee.
3. Chair of the Board.
4. The Articles of the Corporation provide that if Corporation does not hold an annual general meeting in accordance with the *Business Corporations Act*, the Directors then in office shall be deemed to have been elected or appointed as Directors on the last day on which the annual general meeting could have been held pursuant to the *Business Corporations Act* (British Columbia), and they may hold office until other Directors are appointed or elected or until the day on which the next annual general meeting is held.

## 10.2 OFFICERS

The following table sets forth the name, province and country of residence of each executive officer of the Corporation, their respective position and office with the Corporation and his or her principal occupation during the five preceding years as of the date of filing of this Annual Information Form:

| NAME AND RESIDENCE | OFFICE HELD | PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS |
|---|---|---|
| John C. Walker<br>British Columbia, Canada | President and CEO | President & CEO of the Corporation and additionally since July 2010, President & CEO of FortisBC Holdings Inc. and FortisBC Energy Inc. |
| Michael A. Mulcahy<br>British Columbia, Canada | Executive Vice President, Human Resources, Customer & Corporate Services | Executive Vice President, Human Resources, Customer & Corporate Services of the Corporation and of FortisBC Energy Inc. since November, 2011; prior thereto Executive Vice President, Customer & Corporate Services of the Corporation and additionally of FortisBC Energy Inc. since July 2010; prior thereto Vice President, Customer and Corporate Services of the Corporation. |
| Dwain A. Bell<br>British Columbia, Canada | Vice President, Operations | Vice President, Operations of the Corporation and of FortisBC Energy Inc. since November 2011; prior thereto Vice President, Distribution of FortisBC Energy Inc. |
| David C. Bennett<br>British Columbia, Canada | Vice President, General Counsel and Corporate Secretary | Vice President, General Counsel and Corporate Secretary of the Corporation since July 2010 and additionally of FortisBC Holdings Inc. and FortisBC Energy Inc. since May 2007; prior thereto Vice President, Regulatory Affairs, General Counsel and Corporate Secretary of the Corporation since February 2007; prior thereto General Counsel and Corporate Secretary of the Corporation. |

| NAME AND RESIDENCE | OFFICE HELD | PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS |
|---|---|---|
| Roger A. Dall'Antonia<br>British Columbia, Canada | Vice President, Strategic Planning, Corporate Development & Regulatory Affairs | Vice President, Strategic Planning, Corporate Development & Regulatory Affairs of the Corporation and of FortisBC Energy Inc. and additionally CFO and Treasurer of FortisBC Holdings Inc. since January 1, 2012; prior thereto Vice President, Finance and CFO; Treasurer of FortisBC Energy Inc. and additionally Vice President, Finance and Treasurer of FortisBC Holdings Inc. since July 2010; prior thereto Vice President, Corporate Development and Treasurer of FortisBC Energy Inc. since November 2007; prior thereto Vice President, Treasury and Investor Relations of Versacold Income Fund July 2006 to November 2007; prior thereto Vice President, Treasurer of FortisBC Energy Inc. |
| Cynthia Des Brisay<br>British Columbia, Canada | Vice President, Energy Supply & Resource Development | Vice President, Energy Supply & Resource Development of the Corporation and of FortisBC Energy Inc. since February 2011; prior thereto Vice President, Energy Supply & Gas Transmission of the Corporation and additionally of FortisBC Energy Inc. since July 2010; prior thereto Vice President, Gas Supply & Transmission of FortisBC Energy Inc. since May, 2008; prior thereto Director, Business Development & Resource Planning of FortisBC Energy Inc. |
| Michele I. Leeners<br>British Columbia, Canada | Vice President, Finance & CFO | Vice President, Finance & CFO of the Corporation. |
| Thomas A. Loski<br>British Columbia, Canada | Vice President, Customer Service | Vice President, Customer Service of the Corporation and additionally of FortisBC Energy Inc. since October 2010; prior thereto Chief Regulatory Officer of FortisBC Energy Inc. since April, 2008; prior thereto Director Regulatory Affairs of FortisBC Energy Inc. |
| Doyle Sam<br>British Columbia, Canada | Vice President, Engineering & Generation | Vice President, Engineering & Generation of the Corporation and of FortisBC Energy Inc. since November 2011; prior thereto Vice President, Engineering & Operations of the Corporation since February 2008; prior thereto Vice President, Transmission & Distribution of the Corporation. |
| Robert M. Samels<br>British Columbia, Canada | Vice President, Business Planning | Vice President, Business Planning of the Corporation since February 2011 and additionally of FortisBC Energy Inc. since July 2010; prior thereto Vice President, Business Services & Technology of FortisBC Energy Inc. since April 2009; prior thereto Vice President, Business Services and CIO of FortisBC Energy Inc. |

| NAME AND RESIDENCE | OFFICE HELD | PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS |
|---|---|---|
| Douglas L. Stout<br>British Columbia, Canada | Vice President, Energy Solutions & External Relations | Vice President, Energy Solutions & External Relations of the Corporation and additionally of FortisBC Energy Inc. since July 2010; prior thereto Vice President, Marketing & Business Development of FortisBC Energy Inc. |
| Debra G. Nelson<br>British Columbia, Canada | Assistant Corporate Secretary | Assistant Corporate Secretary of the Corporation since July 2010; and additionally and prior thereto Assistant Corporate Secretary and Manager, Corporate Compliance and Secretariat of FortisBC Holdings Inc. and FortisBC Energy Inc. |

Note: Scott A. Thomson was the Executive Vice President, Finance, Regulatory & Energy Supply from July of 2010 until December 31, 2011.

## 10.3 CONFLICTS OF INTEREST

Other than as disclosed herein, to the knowledge of management of the Corporation, there are no existing or potential material conflicts of interest among the Corporation or a subsidiary of the Corporation and any director or officer of the Corporation or such subsidiary.

## 11.0 EXECUTIVE COMPENSATION

The Corporation's Statement of Executive Compensation is attached as Schedule "A".

## 12.0 SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The Corporation does not have a compensation plan under which securities of the Corporation are authorized for issuance. See "Executive Compensation – Stock Option Plans" in Schedule "A" of this Annual Information Form for a description of the Fortis 2006 Stock Option Plan.

## 13.0 INDEBTEDNESS OF EXECUTIVE OFFICERS, DIRECTORS, AND EMPLOYEES

The following table sets forth details of the aggregate indebtedness of all executive officers, directors, and employees and former executive officers, directors and employees outstanding at the date of this Annual Information Form to the Corporation or any of its subsidiaries in connection with (i) the purchase of securities and (ii) all other indebtedness, other than routine indebtedness.

| Aggregate Indebtedness ($) | | |
|---|---|---|
| **Purpose** | **To the Corporation or its Subsidiaries** | **To Another Entity** |
| Share purchases | 133,006.12 (1) | Nil |
| Other | N/A | N/A |

Note:

1. Amount of $133,006.12 represents a stock option exercise loan that is secured by the share certificates held by the officer, bears interest equal to the amount of dividends received on the shares and is due within 10 years of the grant date or within one year following cessation of employment, whichever occurs first.

The following table sets forth details on each individual who is, or at any time during the Corporation's most recently completed financial year was, a director or executive officer of the Corporation or an associate of any such director or executive officer that is, or at any time during the Corporation's most recently completed financial year was, indebted to (i) the Corporation or any of its subsidiaries, or (ii) another entity where such indebtedness is or has been the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries, or other than routine indebtedness.

| Indebtedness of Directors and Executive Officers Under (1) Securities Purchase | | | | | | |
|---|---|---|---|---|---|---|
| **Name & Principle Position** | **Involvement of Corporation or Subsidiary** | **Largest Amount Outstanding During 2011 ($)** | **Amount Outstanding as of date of Filing of this AIF ($)** | **Financially Assisted Securities Purchases During 2011 (#)** | **Security for Indebtedness** | **Amount Forgiven During 2011 ($)** |
| **Securities Purchase Programs** | | | | | | |
| David C. Bennett VP, General Counsel and Corporate Secretary | FortisBC Inc. as lender | 133,006.12(1) | 133,006.12 | 1,450 | see note (1) | Nil |

Note:

1. Amount of $133,006.12 represents a stock option exercise loan that is secured by the share certificates held by the officer, bears interest equal to the amount of dividends received on the shares and is due within 10 years of the grant date or within one year following cessation of employment, whichever occurs first.

## 14.0 INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Corporation, or person or Corporation that beneficially owns, or controls or directs, directly or indirectly, more than 10 per cent of any class or series of the Corporation’s outstanding voting securities, nor any associate of the foregoing persons, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years of the Corporation or during the current financial year of the Corporation that has materially affected or is reasonably expected by the Corporation to materially affect the Corporation.

For more information with respect to the Corporation’s material transactions with related parties, see the section entitled “Related Party Transactions” in the Corporation’s Management Discussion & Analysis for the year ended December 31, 2011, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

## 15.0 MATERIAL CONTRACTS

The following are the only material contracts, other than contracts entered into in the ordinary course of business and not required by applicable securities laws to be filed with a Canadian securities regulatory authority or those that were entered into before January 1, 2002, which have been entered into by the Corporation within the Corporation’s most recently completed financial year, or before the most recently completed financial year but is still in effect:

- the trust indenture dated as of November 30, 2004 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time;
- the CPA (see “The Business of FortisBC Inc. – Generation and Power Supply”); and
- the trust indenture dated as of May 27, 2009 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time.

Copies of the above noted agreements are contained on SEDAR at www.sedar.com.

## 16.0 LEGAL PROCEEDINGS

The Province of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a Writ and Statement of Claim against FBC dated August 2, 2005. The Province of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private land owners have filed separate Writs and Statements of Claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FBC and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time, and accordingly no amount has been accrued in the financial statements.

## 17.0 TRANSFER AGENTS AND REGISTRARS

Computershare Trust Corporation of Canada is the registrar and transfer agent and trustee for the Corporation's debentures. Transfers of these securities may be effected at Computershare Trust Corporation of Canada's offices in the city of Vancouver, British Columbia.

## 18.0 INTEREST OF EXPERTS

Ernst & Young LLP, Chartered Accountants is the auditor of the Corporation and was appointed effective as at March 31, 2005 and each year thereafter. The Corporation's auditor, Ernst & Young LLP, has prepared the audit report attached to the audited consolidated financial statements for the Corporation's financial year ended December 31, 2011. Ernst & Young LLP remains independent with respect of the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

## 19.0 ADDITIONAL INFORMATION

Additional financial information is also provided in the Corporation's financial statements for the financial year ended December 31, 2011, and management's discussion and analysis of such financial results. A copy of such documents and additional information relating the Corporation is contained on SEDAR at www.sedar.com.

## SCHEDULE "A" - EXECUTIVE COMPENSATION

### A. COMPENSATION DISCUSSION AND ANALYSIS

It is the responsibility of the Governance Committee to review, recommend and administer the compensation policies in respect of the Corporation's executive officers. The Governance Committee's recommendations as to base salary and short term incentives are submitted to the Board of the Corporation for approval. Proposed grants to the Corporation's executive officers under the Fortis Stock Option Plan are submitted by the Corporation's Board to the Human Resources Committee of the Fortis Board of Directors for approval.

The Corporation's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance. The Governance Committee recognizes the need to provide a total compensation package that will attract and retain qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of base salary are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of FBC. Long-term incentive plans focus executives on sustained shareholder value creation.

The Corporation has a policy of compensating executive officers at approximately the median (50th percentile) of comparable Canadian commercial industrial companies. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It includes organizations from the energy, mining and manufacturing sectors. Annually, the Governance Committee uses the compensation data from this reference group to compare each executive officer to corresponding positions within the reference group. This framework serves as a guide for the Governance Committee's deliberations. The actual total compensation and/or amount of each compensation component for an individual executive officer may be more or less than the median amount.

Total annual compensation for the executive officers is composed primarily of four main components:

- annual base salary;
- short-term incentive in the form of an annual cash bonus;
- long-term incentive in the form of options to purchase Fortis Shares; and
- pension arrangements.

### REPORT ON CORPORATE GOVERNANCE

#### Governance Committee

The Governance Committee provides assistance to the Board by overseeing the Corporation's policy and performance in matters of corporate governance, including the nomination of Directors; matters of natural environment and safety and specifically, matters of human resource management, including the Corporation's pension plans and compensation of senior officers.

Specifically with regards to executive compensation matters, the responsibilities of the Governance Committee include:

1. Reviewing and making recommendations to the Board with respect to the adequacy and form of the compensation of directors;
2. Reviewing and recommending to the Board the appointment and compensation of senior officers;
3. Reviewing and recommending to the Board the development of policy for orderly succession to senior positions and targets used by the Corporation to measure performance for compensation purposes, and reviewing and reporting to the Board on the overall effectiveness of the senior

management team including the CEO. The Corporation recognizes the importance of appointing knowledgeable and experienced individuals to the Governance Committee. The Governance Committee composition includes members that have the necessary background and skills to provide effective oversight of corporate governance and executive compensation, including adherence with sound risk management principles.

All Governance Committee members have significant senior leadership and/or governance experience. More specifically four of the six members of the Governance Committee have direct operational or functional experience overseeing compensation policies and practices at large organizations similar in complexity to FBC.

In fulfilling its duties and responsibilities with respect to executive compensation, the Governance Committee seeks periodic input, advice, and recommendations from various sources, including the Board, executive officers, and external independent consultants. The Governance Committee retains discretion in its executive compensation decisions and is not bound by the input, advice, and/or recommendations received from the external independent consultant.

The Governance Committee believes that the Corporation's compensation regime appropriately takes into account the performance of the Corporation and the contribution of the President and Chief Executive Officer and other executive officers of the Corporation toward that performance.

The members of the Governance Committee are Beth D. Campbell, Ida J. Goodreau, Harry McWatters, H. Stanley Marshall, Linda S. Petch and Karl W. Smith. These directors are independent directors with the exception of Messrs. Marshall, President & Chief Executive Officer of Fortis Inc. and Smith, President & CEO of FortisAlberta Inc. since May 2007; prior thereto President & CEO of Newfoundland Power Inc.

**Compensation Review Framework**

**Annual Review**

FBC monitors, reviews, and evaluates its executive compensation program annually to ensure that it provides reasonable compensation ranges at appropriate levels and remains competitive and effective.

As part of the annual review process, Fortis engages Hay Group Limited ("Hay Group"), its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian Commercial Industrial companies. Using this data, a detailed review is prepared to analyze the Corporation's competitive compensation positioning against its peer group. Hay Group provides Fortis and its subsidiaries preliminary recommendations to management on the basis of pay competitiveness, emerging market trends and best practices. In addition, the Corporation may from time to time engage Hay Group to provide specific analysis of its executive compensation components.

Management then takes into account the corporate performance against pre-determined objectives and together with the CEO recommends a set of new performance objectives for the following year. Individual performance reviews, incentive award payouts, and compensation adjustments, if any, are also determined at this stage. The CEO does not make recommendations to the Governance Committee with respect to his own compensation.

In the final step, the Governance Committee reviews the recommendations set forward by management and the compensation consultant prior to seeking approval from the Board regarding current year's compensation payouts and next year's performance objectives. The Governance Committee and the Board may exercise discretion when making compensation decisions in appropriate circumstances and make deviations from the prescribed incentive award formulas, if necessary.

### Competitive Positioning

FBC does not measure performance against a particular reference group. However, as a general policy, FBC establishes base and incentive compensation targets so as to compensate executives and in particular, each person who served as the Chief Executive Officer or Chief Financial Officer during the most recently completed financial year and the three most highly compensated executive officers of the Corporation during the most recently completed financial year (the “Named Executive Officers” or “NEOs”), at a level generally equivalent to the median of practice among a broad reference group of approximately 200 Canadian commercial industrial companies. This reference group, (The Commercial Industrial Comparator Group) is compiled by Hay Group. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. This reference group is formally reviewed as part of the Fortis triennial review of executive compensation policy.

### Compensation Risk Considerations

Risk is considered throughout the Corporation’s annual compensation review processes to ensure that effective control systems are in place to mitigate the perceived risks inherent in the compensation structure. The Governance Committee has identified the following external and internal risk controls within the Corporation’s executive compensation program:

### External Compensation Risk Mitigating Controls

With respect to the regulatory environment, there are extensive regulatory frameworks, as well as reporting and approval mechanisms. FBC’s ongoing compliance with existing regulatory requirements and emerging best practices ensure that risks within its compensation program are being continually monitored and controlled.

### Internal Compensation Risk Mitigating Controls

The compensation program is designed such that risk is taken into consideration throughout the compensation review process:

| | |
|---|---|
| **Annual Salary** | • Annual salaries are targeted approximately at market median levels and as such do not encourage excessive risk-taking. |
| **Short-Term Incentives** | • ***Board Discretion***: The Governance Committee retains the discretion to make upwards or downwards adjustments to the prescribed incentive payout formulas and actual payouts based on its assessment of the risk assumed to generate financial results, circumstances that may have influenced individual performance, as well as external factors that may have impacted the Corporation’s financial performance.<br><br>• ***Award Cap***: Short-term incentives awarded to executives are capped at 150 per cent of Annual Salary; however, the Governance Committee retains the discretion to award up to a maximum of 200 per cent of Annual Salary in recognition of individual response to exceptional challenges or opportunities and may make deviations in appropriate circumstances. |

| | |
|---|---|
| **Long-Term Compensation** | • ***Stock Option Grants linked directly to Stock Ownership Requirements***: Share ownership for executives, including the NEOs, is encouraged through Fortis' Executive Compensation Policy, whereby the options granted each year to any executive are limited to the lesser of the number of options prescribed to that particular position and the minimum number of shares actually owned by the individual since the beginning of the previous calendar year. While minimum share holdings are not formally prescribed by policy tying the number of stock options grants to the executive's share holdings has achieved high levels of executive ownership.<br><br>• ***Anti-Hedging Policy*****:** The Corporation's executive officers are not permitted to hedge against declines in the market value of equity securities received as compensation. |

**Compensation Consultants**

As noted above, Fortis engages Hay Group as its primary compensation consultant.

Hay Group has served as the primary external independent advisor on matters relating to executive compensation since 2004. In addition to matters related to executive compensation, Hay Group also provides the Corporation with general market compensation data from its national database.

The Corporation also engages Towers Watson and Mercer (Canada) Limited to consult on certain pension and benefit components and to perform certain administrative and actuarial functions related to the Corporation's pension programs.

In regards to non-union pension matters, the Governance Committee appoints the pension plan's Actuary, Custodians and Investment manager, and Auditors for Financial Statements. The Board approves employer/employee contribution rates, establishes or terminates pension plans, is the fiduciary and administrator for plans, approves the governance structure, major plan design changes, and approves the mandate of the Governance Committee.

The following table sets forth information concerning fees paid by the Corporation to compensation consultants in 2010 and 2011.

| Type of Fee by Consultant | 2011 Consultant Fees ($) | 2010 Consultant Fees ($) |
|---|---|---|
| Executive Compensation Consulting (1) | 4,471 | 6,784 |
| All other Fees (2) | 8,599 | - |

Notes:

1. Fees paid to the Hay Group related to executive compensation.
2. Fees paid to Towers Watson related to benefit and market data.

**Performance Graph**

None of the Corporation's equity securities (as defined in applicable securities laws) are publicly traded. There is, therefore, no performance graph.

## Elements of Total Compensation

Total annual compensation for the executive officers involves a significant proportion that is at risk due to the use of short-term and long-term incentive components. For 2011, approximately 50 per cent of the President & Chief Executive Officer's total annual compensation was designed to be at risk. Approximately 40 per cent of the other NEO's total annual compensation was designed to be at risk. Total annual compensation includes both the cash compensation paid to the executive officers in the year and the estimated compensation for the long-term incentive components. The estimated value of the long-term incentive components is determined using the Black-Scholes pricing model at the date of grant of options.

The executive compensation regime is structured in a manner that recognizes the greater ability of the President & Chief Executive Officer to affect corporate performance by making a greater portion of that individual's compensation dependent upon corporate performance.

The elements of compensation of the NEOs and their respective compensation objectives are set out below:

| Compensation Element *(Eligibility)* | Description | Compensation Objectives |
|---|---|---|
| **Annual Base Salary and Annual Incentive** | | |
| Annual Base Salary<br>*(all NEOs)* | Salary is a market-competitive, fixed level of compensation. | Attract and retain highly qualified executives.<br><br>Motivate strong business performance. |
| Annual Incentive<br>*(all NEOs)* | Combined with salary, the target level of annual incentive is intended to provide executives with a market-competitive total cash opportunity.<br><br>Annual incentive payout depends on individual and corporate performance. | Attract and retain highly qualified executives.<br><br>Motivate strong business performance.<br><br>Compensation dependent on individual and corporate performance.<br><br>Simple to communicate and administer. |
| **Long-term Equity Based Incentive** | | |
| Stock Options<br>*(all NEOs)* | Annual equity grants are made in the form of stock options.<br><br>The amount of annual grant will be dependent on the level of the executive and their current share ownership levels.<br><br>Planned grant value is converted to the number of shares granted by dividing the planned value by the pre-determined, formulaic planning price derived using the Black-Scholes Option Pricing Model.<br><br>Options vest over a 4 year period. | Align executive and shareholder interests.<br><br>Attract and retain highly qualified executives.<br><br>Encourage strong long-term business performance.<br><br>Balance compensation for short and long-term strategic results.<br><br>Simple to communicate and administer. |
| **Pension Plans** | | |
| Defined Benefit Pension Plan<br>(*certain NEOs)* | Payout upon retirement based on the number of years of credited service and actual pensionable earnings. | Attract and retain highly qualified executives.<br><br>Simple to communicate and administer. |

| Compensation Element *(Eligibility)* | Description | Compensation Objectives |
|---|---|---|
| RRSP *(certain NEOs)* | Contribution to a registered retirement savings plan equal to 6.5 per cent of a member's base salary which is matched by the member up to the maximum contribution limit allowed by the Canada Revenue Agency. | Attract and retain highly qualified executives.<br><br>Simple to communicate and administer. |
| Defined Contribution: Supplemental Employee Retirement Plan (SERP) *(all NEOs)* | Accrual of 13 per cent of base salary and annual incentive in excess of the Canada Revenue Agency limit.<br><br>At time of retirement, paid in one lump sum or in equal payments up to 15 years. | Attract and retain highly qualified executives.<br><br>Simple to communicate and administer. |

**Annual Base Salary**

Annual base salaries paid to the Corporation's NEOs are determined by the Board upon recommendation by the Governance Committee and are established annually by reference to the range of salaries paid at approximately the median of the salaries paid to executives in comparably rated positions of comparable Canadian commercial industrial companies.

**Annual Incentive**

NEOs participate in an annual incentive plan that provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets approved by the Board of Directors upon recommendation by the Governance Committee. The Corporation's annual earnings must reach a minimum threshold level before any payments are made. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Corporation.

Corporate performance is determined with reference to the performance of the Corporation relative to weighted targets in respect to financial, safety, customer service, reliability and regulatory performance. There were five targets in 2011 which included (i) regulated earnings (30.0 per cent weighting); (ii) an all injury frequency rate (AIFR) which measures how safely the Corporation operate (15 per cent weighting); (iii) customer satisfaction of which measures customer service by quarterly customer surveys (12.5 per cent weighting); (iv) system average interruption duration index which measures reliability of power distribution system in terms of duration of outages (12.5 per cent weighting); and (v) regulatory performance (30 per cent weighting). Regulated earnings are representative of the achieved return on equity subject to "Incentive Adjustments" based on allowed return on equity as approved by the BCUC

Individual performance is determined with reference to individual contribution to corporate objectives, elements of which are subjective. For the Chief Executive Officer, 80 per cent of the annual cash bonus is based on corporate targets and 20 per cent is based upon personal targets. For each of the other NEOs, 50 per cent of the annual cash bonus is based upon corporate targets and 50 per cent is based upon personal targets. At the discretion of the Board of Directors, executives may be awarded up to an additional 50 per cent of target incentive pay in recognition of exceptional performance contributions.

**Stock Option Plan**

The 2006 Stock Option Plan was approved by the shareholders of Fortis on May 2, 2006 for the purposes of granting options in the common shares of Fortis to certain eligible persons, which includes the Corporation's NEOs (the "Eligible Persons") in order to encourage increased share ownership by key employees as an incentive to maximize shareholder value. The directors of Fortis or any of its subsidiaries are not eligible to participate in the 2006 Stock Option Plan. No options may be granted under the 2006 Stock Option Plan if, together with any other security based compensation arrangement established or maintained by Fortis, such granting of options could result, at any time, in (a) the number of common shares issuable to insiders of Fortis, at any time, exceeding 10 per cent of the issued and outstanding common shares and, (b) the number of common shares issued to insiders of Fortis, within any one year period, exceeding 10 per cent of the issued and outstanding common shares.

The 2006 Stock Option Plan is administered by Fortis. Pursuant to the 2006 Stock Option Plan, the determination of the exercise price of options is made by the Human Resources Committee of Fortis at a price not less than the volume weighted average trading price of the common shares of Fortis determined by dividing the total value of the common shares traded on the TSX during the last 5 trading days immediately preceding the date by the total volume of the common shares traded on the TSX during such 5 trading days. Options may not be amended to reduce the option price. The Human Resources Committee of Fortis determines: (i) which Eligible Persons are granted options; (ii) the number of common shares covered by each option grant based on the salary level of an Eligible Person; (iii) the price per share at which common shares may be purchased; (iv) the time when the options will be granted; (v) the time when the options will vest; and (vi) the time at which the options will be exercisable (up to 7 years from the date of grant). Options granted under the 2006 Stock Option Plan are personal to the Eligible Person and not assignable, other than by testate succession or the laws of decent and distribution. In the event that a person ceases to be an Eligible Person, the 2006 Stock Option Plan will no longer be available to such person. The grant of options does not confer any right upon an Eligible Person to continue employment or to continue to provide services to FBC.

Options granted pursuant to the 2006 Stock Option Plan have a maximum term of 7 years from the date of grant and the options will vest over a period of not less than 4 years from the date of grant, provided that no option will vest immediately upon being granted. Options granted pursuant to the 2006 Stock Option Plan will expire no later than 3 years after the termination, death or retirement of an Eligible Person.

Eligible Persons are granted stock options based on salary levels. In 2011, the President and Chief Executive Officer of the Corporation was granted an option entitling him to purchase that number of common shares of Fortis having a market value at the time of grant equal to 300 per cent of his base salary. Each of the other NEOs were granted an option entitling each NEO to purchase that number of common shares having a market value at the time of grant equal to 150 per cent of such NEO's base salary, however, where a NEO has been granted options for 5 or more prior years, the maximum number of shares for which options will be granted in any calendar year will not exceed the minimum number of shares held by the NEO since the beginning of the previous year.

The 2006 Stock Option Plan provides that notwithstanding provisions in the plan to the contrary, no option maybe amended to reduce the option price below the option price as of the date the option is granted.

**Pension Plans –** see "Executive Compensation – Pension Plan Benefit"

## B. SUMMARY COMPENSATION TABLE

The following table sets forth information concerning the annual and long-term compensation earned for services rendered in respect of each of the individuals who were, at December 31, 2011, the President & Chief Executive Officer, the Chief Financial Officer and the Corporation's three most highly paid executive officers (the "Named Executive Officers", each an "Executive").

| Name and principal position | Year | Salary ($) | Option-based awards ($)(1) | Annual incentive plans(2) | Pension value ($)(3) | All other compensation ($)(4) | Total compensation ($)(5) (6) |
|---|---|---|---|---|---|---|---|
| John C. Walker President & CEO FortisBC Inc. | 2011 | 500,000 | 277,399 | 425,000 | 102,157 | 56,195 | 1,360,751 |
| | 2010 | 453,192 | 186,173 | 310,000 | 80,698 | 94,442 | 1,124,505 |
| | 2009 | 385,000 | 212,462 | 231,000 | 60,669 | 64,983 | 954,114 |
| Michele I. Leeners Vice President, Finance and CFO FortisBC Inc. | 2011 | 235,000 | 48,899 | 150,000 | 34,925 | 11,336 | 480,160 |
| | 2010 | 230,000 | 55,619 | 120,000 | 32,550 | 9,531 | 447,700 |
| | 2009 | 230,000 | 63,468 | 105,000 | 31,750 | 1,743 | 431,961 |
| Michael A. Mulcahy Executive Vice President, Customer and Corporate Services FortisBC Inc. | 2011 | 281,000 | 58,459 | 190,000 | 42,335 | 9,441 | 581,235 |
| | 2010 | 252,846 | 55,196 | 131,000 | 35,475 | 43,366 | 517,883 |
| | 2009 | 230,000 | 49,216 | 105,000 | 31,100 | 51,961 | 467,277 |
| Doyle Sam Vice President, Engineering and Operations FortisBC Inc. | 2011 | 251,000 | 47,857 | 165,000 | 34,405 | 5,354 | 503,617 |
| | 2010 | 230,000 | 55,619 | 100,000 | 32,550 | 4,398 | 422,567 |
| | 2009 | 230,000 | 63,468 | 105,000 | 31,100 | 3,105 | 432,673 |
| David C. Bennett Vice President, General Counsel and Corporate Secretary FortisBC Inc. | 2011 | 230,800 | 35,061 | 125,000 | 32,819 | 20,991 | 444,671 |
| | 2010 | 225,000 | 54,402 | 108,000 | 31,900 | 18,581 | 437,883 |
| | 2009 | 225,000 | 62,090 | 105,000 | 31,750 | 24,175 | 448,015 |

Notes:

1. Represents the fair value of options granted by Fortis to acquire common shares of Fortis. The fair values of $4.57 per option were determined at the date of grant using the Black-Scholes Option Pricing Model and the following assumptions:

   Dividend yield (%) 3.68
   Expected volatility (%) 23.1
   Risk-free interest rate (%) 2.00
   Weighted average expected life (years) 4.5
2. Represents amounts earned under the Corporation's short-term non-equity incentive program in recognition of performance for the reported year and paid in the following year.
3. Represents compensation paid or accrued relating to the defined benefit, defined contribution, RRSP and the SERP.
4. Includes, where applicable the aggregate of amounts paid by FBC for payment in lieu of vacation, insurance premiums, employee share purchase dividend and flexible benefit plan taxable cash. Only includes perquisites, including property or other personal benefits provided to a NEO that are not generally available to all employees, and that are in the aggregate worth of $50,000 or more, or are worth 10 per cent or more of a NEO's salary.

5. Amounts reported represent amounts paid by FBC for Mr. Walker's and Mr. Bennett's services to FBC, FHI and FEI. FBC is proportionately reimbursed for their services.
6. Ms. Leeners, Mr. Mulcahy and Mr. Sam provide services to FEI for which FBC is proportionately reimbursed for the services that were provided.

## C. INCENTIVE PLAN AWARDS

The following table sets details of all outstanding unexercised options held by each NEO. The aggregate value is based on the difference between the Fortis share price at December 31, 2011 of $33.37 and the exercise price of the options. The table below includes stock option information that is a reflected on a post-split basis.

| Option-based awards | | | | |
|---|---|---|---|---|
| **Name** | **Number of securities underlying unexercised options (#)** | **Option exercise price ($)** | **Option expiration date** | **Value of unexercised in-the-money options ($)** |
| John C. Walker | 22,496 | 15.28 | 10-Mar-14 | 406,952.64 |
| | 39,392 | 18.405 | 1-Mar-15 | 589,501.28 |
| | 34,329 | 22.94 | 28-Feb-16 | 358,051.47 |
| | 36,184 | 28.19 | 7-May-14 | 187,433.12 |
| | 38,204 | 28.27 | 26-Feb-15 | 194,840.40 |
| | 51,820 | 22.29 | 11-Mar-16 | 574,165.60 |
| | 42,216 | 27.36 | 1-Mar-17 | 253,718.16 |
| | 60,700 | 32.95 | 2-Mar-18 | 25,494.00 |
| | **325,341** | | | **2,590,156.67** |
| Michele I. Leeners | 11,443 | 22.94 | 28-Feb-16 | 119,350.49 |
| | 10,908 | 28.19 | 7-May-14 | 56,503.44 |
| | 11,408 | 28.27 | 26-Feb-15 | 58,180.80 |
| | 7,740 | 22.29 | 11-Mar-16 | 85,759.20 |
| | 12,612 | 27.36 | 1-Mar-17 | 75,798.12 |
| | 10,700 | 32.95 | 2-Mar-18 | 4,494.00 |
| | **64,811** | | | **400,086.05** |
| Michael A. Mulcahy | 20,856 | 12.81 | 13-Mar-13 | 428,799.36 |
| | 15,240 | 18.405 | 1-Mar-15 | 228,066.60 |
| | 12,751 | 22.94 | 28-Feb-16 | 132,992.93 |
| | 10,908 | 28.19 | 7-May-14 | 56,503.44 |
| | 11,408 | 28.27 | 26-Feb-15 | 58,180.80 |
| | 12,004 | 22.29 | 11-Mar-16 | 133,004.32 |
| | 12,516 | 27.36 | 1-Mar-17 | 75,221.16 |
| | 12,792 | 32.95 | 2-Mar-18 | 5,372.64 |
| | **108,475** | | | **1,118,141.25** |

| Option-based awards | | | | |
|---|---|---|---|---|
| Doyle Sam | 10,908 | 28.19 | 7-May-14 | 56,503.44 |
| | 11,408 | 28.27 | 26-Feb-15 | 58,180.80 |
| | 7,740 | 22.29 | 11-Mar-16 | 85,759.20 |
| | 12,612 | 27.36 | 1-Mar-17 | 75,798.12 |
| | 11,428 | 32.95 | 2-Mar-18 | 4,799.76 |
| | **54,096** | | | **281,041.32** |
| David C. Bennett | 5,608 | 28.19 | 7-May-14 | 29,049.44 |
| | 10,720 | 28.27 | 26-Feb-15 | 54,672.00 |
| | 11,358 | 22.29 | 11-Mar-16 | 125,846.64 |
| | 12,336 | 27.36 | 1-Mar-17 | 74,139.36 |
| | 7,672 | 32.95 | 2-Mar-18 | 3,222.24 |
| | **47,694** | | | **286,929.68** |

The following table sets forth the value of option based awards and non-equity incentive plan compensation vested or earned by the NEO during the most recently completed financial year. The aggregate value of the option based awards vested during the year is based on the difference between the Fortis share price on the vesting date of any options that vested during 2011 and the exercise price of the options.

| Name | Option based awards value vested during 2011 ($) | Non-equity incentive plan compensation-value earned during 2011 ($) |
|---|---|---|
| John C. Walker | 251,528 | 425,000 |
| Michele I. Leeners | 75,284 | 150,000 |
| Michael A. Mulcahy | 67,444 | 190,000 |
| Doyle Sam | 75,284 | 165,000 |
| David C. Bennett | 65,587 | 125,000 |

## D. PENSION PLAN BENEFITS

The following table sets forth the details of the defined benefit pension plans ("DB") for the following NEO.

| Name | Number of years credited service (#) | Annual benefits payable ($) | | Opening present value of DB obligation ($) | Compensatory change ($) | Non-compensatory change ($) | Closing present value of DB obligation ($) |
|---|---|---|---|---|---|---|---|
| | | At year end | At age 65 | | | | |
| John C. Walker | 28.66 | 95,299 | 116,371 | 797,592 | 20,535 | 131,528 | 949,655 |

The information shown in the defined benefit pension plan table above has been calculated using the valuation method and actuarial assumptions described in the pension note in the Corporation's annual financial statements for 2011.

Mr. Walker participates in the Fortis Inc. Retirement Income Plan (the "DB RPP"). The DB RPP provides for an annual accrual of 1.33 per cent up to final average years maximum pensionable earnings ("YMPE") as defined under the Canada Pension Plan and 2 per cent in excess of the final average YMPE (limited to $182,000 per year) up to the NEO's best average earnings. The best average earnings are based on the 36 consecutive months of service during which earnings were highest. The final average YMPE is based on the final 36 months of service. The DB RPP provides a payout upon retirement based on the number of years of credited service and actual pensionable earnings and has a maximum accrual period of 35 years.

Mr. Walker also participates in the Fortis Inc. Pension Uniformity Plan (the "DB PUP"). The DB PUP provides the portion of the calculated pension that cannot be provided under the DB RPP due to limits prescribed by the Income Tax Act. For the purposes of the DB PUP, the recognized earnings are limited to the base earnings rate that was in effect at December 31, 1999.

The following table sets forth the details of the supplemental employee retirement plan for the respective NEOs.

| **Name** | **Accumulated value at start of year ($)** [1] | **Compensatory ($)** | **Accumulated value at year end ($)** [2] |
|---|---|---|---|
| John C. Walker | 834,343 | 81,640 | 965,225 |
| Michele I. Leeners | 111,403 | 23,700 | 139,690 |
| Michael A. Mulcahy | 263,432 | 31,110 | 307,481 |
| Doyle Sam | 121,539 | 23,180 | 149,606 |
| David C. Bennett | 84,254 | 21,594 | 109,421 |

Notes:

1. Adjustments were made to the value at 2010 year end after the 2010 Annual Information Form filing to remove RRSP employer contribution. These amounts were disclosed in the Summary Compensation Table.
2. Includes non-compensatory amount, including regular investment earnings on contributions, which are not included as a separate column in the table above.

Mr. Walker, Ms. Leeners, Mr. Mulcahy, Mr. Sam and Mr. Bennett participate in a defined contribution supplemental employee retirement plan (the "DC SERP"). The DC SERP provides for the accrual by FBC of an amount equal to 13 per cent of the annual base salary of a participant and an annual cash incentive in excess of the allowed Canada Revenue Agency limit to a notional account which accrues interest equal to the rate of a 10-year Government of Canada Bond plus a premium of 0 per cent to 3 per cent dependent upon years of service. At the time of retirement, the notional amounts accumulated under the DC SERP may be paid to the participant in one lump sum or in equal payments up to 15 years.

In addition, Ms. Leeners, Mr. Mulcahy, Mr. Sam and Mr. Bennett participate in a RRSP which requires the Corporation to contribute to a self-directed registered retirement savings plan equal to 6.5 per cent of a member's base pay salary which is matched by the member up to the maximum contribution limit allowed by the Canada Revenue Agency. In 2011, the Corporation contributed $11,225 for each of the NEO's participating in the defined contribution retirement plan.

## E. TERMINATION AND CHANGE OF CONTROL BENEFITS

There are no contracts, agreements, plans or arrangements that provide for payments to Mr. Walker, Ms. Leeners, Mr. Bennett, Mr. Sam, and Mr. Mulcahy at, following or in connection with any termination (whether voluntary, involuntary or constructive), resignation, retirement, a change in control of the Corporation or a change in a NEO's responsibilities (excluding perquisites and other personal benefits if the aggregate of this compensation is less than $50,000).

## F. DIRECTOR COMPENSATION

The directors of FBC also serve on the respective boards of FEI and FHI, and the companies share the total board compensation costs proportionately. Directors (other than directors who are officers or employees of FBC, FEI or FHI) are paid an annual director retainer of $35,000. Meeting fees of $1,250 are paid for each Board meeting and for each committee meeting attended. In lieu of a director's retainer, the Chair of the Board receives an annual retainer of $67,500. The Chair of the Audit & Risk Committee and the Chair of the Governance Committee receive an additional annual retainer of $8,000 and $4,000 respectively. The directors were reimbursed for miscellaneous out-of-pocket expenses incurred in carrying out their duties as directors and each director that attended a group of meetings outside of their regional area of residence was paid an additional $1,000 for travel time.

The following table sets forth the aggregate amounts of individual director compensation which were proportionately paid by FBC, FEI and FHI in 2011.

| **Name** | **Fees earned ($)** | **All other compensation (4) ($)** | **Total ($)** |
|---|---|---|---|
| Harold G. Calla (1) | 58,000 | 2,000 | 60,000 |
| Brenda Eaton | 50,000 | 4,000 | 54,000 |
| Harry McWatters | 46,250 | 4,000 | 50,250 |
| Roger M. Mayer | 50,000 | 5,000 | 55,000 |
| Linda S. Petch | 48,750 | 4,000 | 52,750 |
| Beth D. Campbell (2) | 47,750 | 1,000 | 48,750 |
| Ida J. Goodreau | 48,750 | 5,000 | 53,750 |
| H. Stanley Marshall (3) | 83,750 | 4,000 | 87,750 |
| Barry V. Perry | 48,750 | 4,000 | 52,750 |
| David R. Podmore | 50,000 | 2,000 | 52,000 |
| Karl W. Smith | 47,500 | 4,000 | 51,500 |

Notes:

1. Chair of the Audit & Risk Committee.
2. Chair of the Governance Committee.
3. Chair of the Board.
4. All other compensation includes $1,000 for travel time for each group of meetings attended in person outside the director's regional area of residence.

# FORTISBC Inc.

## MANAGEMENT DISCUSSION & ANALYSIS

## For the Year Ended December 31, 2011

Dated February 9, 2012

*The following discussion of the financial condition and results of operations of FortisBC Inc. ("the Corporation" or "FortisBC") should be read in conjunction with the Corporation's annual audited consolidated financial statements and related notes for the years ended December 31, 2011 and December 31, 2010.*

*The financial information included in the discussion provided in this report has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), and all dollar amounts are in Canadian dollars.*

### FORWARD LOOKING STATEMENT

Certain statements in this Management Discussion and Analysis ("MD&A") contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes, but is not limited to, statements regarding the Corporation's expectations to meet interest payments on outstanding indebtedness from internally generated funds; the Corporation's expected level of capital expenditures and its expectations to finance those capital expenditures through lines of credit, debt issues, equity contributions and internally generated funds and the Corporation's expectation of earnings growth in future years given the assumption of a consistently applied regulated capital structure and return on equity, recovery of its cost-of-service components in rates, growth in rate base assets as a result of its annual capital expenditures, and the expected impact of the adoption of new accounting standards including US generally accepted accounting principles ("US GAAP").

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; the expected impact of the transition to new accounting standards including US GAAP, the ability to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2014; absence of equipment breakdown; absence of environmental damage; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; the First Nations' settlement process does not adversely affect the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain skilled workforces; absence of information technology infrastructure failure; no significant decline in interest rates; continued electricity demand; the ability to arrange sufficient and cost effective financing; no material adverse ratings actions by credit rating agencies; that counterparties do not default on power supply contracts; no weather related demand loss; and, climate change does not reduce water flows.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; transition to new accounting standards risk; equipment breakdown, operating and maintenance risk; environmental matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving First Nations; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; interest rate risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competiveness and commodity price risk; power supply contracts risk; weather related demand loss risk; climate change risk; and, other risks described in the Corporation's most recent Annual Information Form. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A.

All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

## CORPORATE OVERVIEW

FortisBC is an integrated, regulated electric utility operating in the southern interior of British Columbia, serving approximately 162,000 customers directly and indirectly, focusing on the safe delivery of reliable and cost effective electricity.

The Corporation's regulated business includes four hydroelectric generating plants with an aggregate capacity of 223 megawatts ("MW"), approximately 7,000 kilometers of transmission and distribution power lines, and a peak demand of 746 MW. Included in FortisBC's non-regulated assets is a 16 MW run-of-river hydroelectric power plant near Lillooet, British Columbia.

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations, pursuant to the *Utilities Commission Act* (British Columbia) covering such matters as tariffs, rates, construction, operations, financing and accounting.

FortisBC operates primarily under a cost of service regulation as prescribed by the BCUC. The Corporation applies to the BCUC for annual revenue requirements based on estimated costs of service, including, but not limited to, operating expenses, power purchases, depreciation and amortization, income taxes, interest on debt and a return on equity ("ROE"). In addition, the regulatory framework through to the end of 2011 included some performance-based rate setting ("PBR") attributes as discussed further under "Regulation" below.

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. ("Fortis"), a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

## REGULATION

### PBR

On April 19, 2006, FortisBC and a group of intervenors concluded negotiations on the Corporation's 2006 Revenue Requirement application. In addition to an agreement on the increase to customer rates required for 2006, the settlement agreement set 2006 as the base year for a PBR term from 2006 to 2008, with an option to extend the term to 2009. The settlement agreement was approved by the BCUC on May 23, 2006.

The significant terms of the PBR agreement negotiated in 2006 were as follows:

- annual gross operating and maintenance expenses before capitalized overhead were set by formula incorporating customer growth and inflation (CPI for British Columbia) minus a productivity improvement factor ("PIF") of 2 per cent in 2007, 2 per cent in 2008 and, if applicable, 3 per cent in 2009;
- annual capitalized overhead will be set at 20 per cent of the BCUC approved gross operating and maintenance expense;
- other components of revenue requirements will be forecast annually; and
- a 2 per cent collar around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally between customers and the shareholder. If the variance exceeds the 2 per cent collar, the excess will be placed in a deferral account for review and disposition during the next rate setting process. The Corporation's portion of the incentive was subject to the Corporation meeting certain performance standards and BCUC approval.

As part of the approval of 2009 Revenue Requirements on December 11, 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement were consistent with the May 23, 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead were set by formula incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess would be added to the PIF which effectively caps the CPI at 3 per cent.

**2011 Revenue Requirements and Capital Expenditure Plan ("CEP")**

On December 23, 2010, the BCUC approved a 6.6 per cent rate increase effective January 1, 2011 which included the impacts of the 2011 Revenue Requirements negotiated settlement agreement and the 2011 CEP which was approved on December 17, 2010. The BCUC also approved a rate increase of 1.4 per cent effective June 1, 2011, arising from an increase in 2011 power purchase expense due to a rate increase approved for BC Hydro ("BCH"). Rates for 2011 reflect an allowed ROE of 9.90 per cent and an equity component of capital structure at 40 per cent.

**2012-2013 Revenue Requirements Application, 2012-2013 CEP and Integrated System Plan ("ISP")**

On June 30, 2011, FortisBC filed its 2012-2013 Revenue Requirements Application ("2012-2013 RRA"), which included the 2012-2013 CEP, with the BCUC, along with the Corporation's ISP. The ISP includes the Corporation's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC had requested an interim 4.0 per cent rate increase for electricity customers effective January 1, 2012 and a 6.9 per cent increase effective January 1, 2013. The rate increases are required due to ongoing investment in infrastructure, the higher cost of capital and increased power purchase costs. Requested rates for 2012 and 2013 reflect an allowed ROE of 9.9 per cent and an equity component of capital structure at 40 per cent. In addition to a continuation of deferral accounts and flow through treatments that existed under the PBR period, the 2012-2013 RRA requests deferral accounts and flow-through treatment for variances from the forecast used to set rates for electricity revenue, power purchase costs and certain other costs.

On November 4, 2011, FortisBC filed an Evidentiary Update amending the 2012-2013 RRA to include updated financial estimates and forecasts. The net impact of the changes was a reduction to the requested rate increases from 4.0 per cent to 1.5 per cent in 2012 and from 6.9 per cent to 6.5 per cent in 2013. On November 30, 2011, the BCUC issued an Order stating that the 2012-2013 RRA would be reviewed through an oral hearing process to take place March 5, 2012 and that an interim refundable rate increase of 1.5 per cent effective January 1, 2012 be approved.

**Generic Cost of Capital Proceeding**

In late 2011, the BCUC issued preliminary notification to all BC regulated utilities, including the Corporation, that it plans to initiate a generic cost of capital proceeding in early 2012. The BCUC intends to review setting the appropriate cost of capital for a benchmark low risk utility; establishing an ROE automatic adjustment mechanism; and establishing a deemed capital structure and deemed cost of capital for those utilities without third party debt. The review by the BCUC may affect both the deemed equity component of capital structure and the return on the equity that the Corporation earns.

Further information on the terms of the PBR agreement, the 2012-2013 RRA, the 2012-2013 CEP and ISP, and the Generic Cost of Capital Proceeding can be found on the BCUC website (www.bcuc.com).

## FINANCIAL RESULTS

Net earnings for the year ended December 31, 2011 were $47.5 million, an increase of $5.7 million from the $41.8 million of net earnings for 2010. As approved by the BCUC, 2010 and 2011 electricity rates reflected an allowed ROE of 9.90 per cent and a deemed equity component of capital structure of 40 per cent.

The increase in net earnings was primarily due to the following:

- a 6.6 per cent rate increase effective January 1, 2011, driven primarily by ongoing investment in electricity infrastructure,
- the actual variances from the 2011 forecast used to set rates in establishing the 6.6 per cent customer rate increase, which primarily include a decrease in power purchase costs, partially offset by lower other revenue due to higher incentives owing back to customers as these variances are shared equally between customers and FortisBC as described in “Other Revenue” below, and
- lower than normal electricity sales during the first quarter of 2010 due to unfavourable weather conditions,

partially offset by

- a decrease in allowance for funds used during construction (capitalized financing costs) as a result of less assets under construction during the period, and
- higher income taxes resulting from lower tax timing differences.

**Consolidated Financial Results**

| Year Ended December 31 | **2011** | 2010 [3] | Variance |
|---|---|---|---|
| **Electricity Sales** (GWh) | **3,183** | 3,082 | 101 |
| ($000s) | | | |
| Electricity Revenue | **279,408** | 248,821 | 30,587 |
| Other Revenue [1] | **4,540** | 10,890 | (6,350) |
| Power Purchase Costs | **71,581** | 72,975 | (1,394) |
| Operating Costs | **70,773** | 63,873 | 6,900 |
| Depreciation and Amortization | **45,260** | 41,620 | 3,640 |
| Finance Charges [2] | **39,440** | 35,298 | 4,142 |
| Income Taxes | **9,396** | 4,185 | 5,211 |
| **Net Earnings** | **47,498** | 41,760 | 5,738 |

[1] Includes equity component of allowance for funds used during construction (capitalized financing costs).

[2] Net of debt component of allowance for funds used during construction (capitalized financing costs).

[3] Certain comparative figures have been reclassified to comply with the current period’s classification.

**Electricity Sales**

The increase in electricity sales was primarily attributable to customer growth and lower than normal electricity sales during the quarter ended March 31, 2010 due to unfavourable weather conditions.

**Electricity Revenue**

The increase in electricity revenue was primarily due to:

- a 6.6 per cent rate increase effective January 1, 2011,
- a 1.4 per cent rate increase effective June 1, 2011 and a 2.9 per cent rate increase effective September 1, 2010. These two rate increases were due to increased power purchase costs charged by BCH, and
- an increase in electricity sales.

**Other Revenue**

Other revenue includes incentive adjustments associated with the PBR framework under which FortisBC operates. Under the terms of the PBR agreement, variances in certain revenues and costs as compared to the forecast will be recovered from (refunded to) customers. In addition, the ROE resulting from actual financial performance is compared to the Corporation's allowed ROE and variances, positive or negative (adjusting for certain revenue and cost variances which flow through to customers), up to a 2 per cent collar, will be shared equally between customers and FortisBC. The remainder of other revenue consists of the equity component of allowance for funds used during construction (capitalized financing costs), management fees for third party contract work, pole attachment revenue, interest income, surplus electricity sales, wheeling revenue and other miscellaneous rental revenues.

The decrease in other revenue was primarily due to an increase in PBR incentive adjustments to be refunded to customers, lower surplus electricity sales and a decrease in the equity component of allowance for funds used during construction, partially offset by an increase in wheeling revenue.

**Power Purchase Costs**

Power purchase costs represent the cost of purchasing energy and capacity from third parties. Hydroelectric generating facilities owned by FortisBC generate approximately 45 per cent of the energy and 30 per cent of the peak capacity necessary to meet existing customer demand.

The decrease in power purchase costs was primarily due to lower average power purchase prices, partially offset by increased electricity sales.

**Operating Costs**

Operating costs include operating and maintenance expenses, property taxes, water fees and wheeling.
The increase in operating costs was primarily due to:

- an additional $3.5 million in operating and maintenance costs primarily relating to vegetation management as approved by the BCUC,
- increased operating and maintenance costs due to labour escalation and general inflationary increases, and
- an increase in property taxes due to a larger assessment base,
- partially offset by an increase in capitalized overhead.

**Depreciation and Amortization**

The increase in depreciation and amortization was primarily due to the increase in the depreciable asset base resulting from the Corporation's capital expenditure program.

**Finance Charges**

The increase in finance charges was primarily due to an increase in borrowings to finance the capital expenditure program and a decrease in the debt component of allowance for funds used during construction (capitalized financing costs), partially offset by lower bank fees.

## Income Taxes

The increase in income tax expense was primarily due to an increase in earnings before income taxes and lower income tax timing differences as compared to 2010, partially offset by a reduction in the combined Federal and Provincial income tax rates.

Included in the income tax expense for the year ended December 31, 2011 are future income tax expenses of $9.1 million primarily attributable to timing differences relating to capital expenditures. These future income tax expenses are offset in regulatory assets by the expected amounts to be recovered from customers in the future, resulting in no significant earnings impact for the year ended December 31, 2011.

# FINANCIAL POSITION

## Significant Changes in Consolidated Balance Sheets

As at December 31, 2011 compared to December 31, 2010

| Balance Sheet Item | Increase (Decrease) |
|---|---|
| ($ millions) | |
| Accounts receivable | (6.4) |
| Regulatory assets | 15.3 |
| Property, plant and equipment | 45.6 |
| Accounts payable and accrued charges | (13.6) |
| Current and long-term debt | 15.9 |
| Future income taxes [1] | 9.1 |
| Retained earnings | 31.5 |

[1] Net of future income tax assets.

## Explanation of Significant Changes

### Accounts Receivable

The decrease of $6.4 million was primarily due to capital expenditure costs recoverable from BCH as at December 31, 2010 which were no longer outstanding at December 31, 2011 and the timing of certain customer payments.

### Regulatory Assets

The increase of $15.3 million was primarily due to the recognition of $9.1 million in future income tax liability, an increase of $0.5 million relating to asset retirement obligations and an increase of $0.4 million relating to the Brilliant Terminal Station ("BTS") asset and obligation under capital lease, all of which have been offset by a regulatory asset of the same amount. In addition, there was a $3.0 million increase in energy management costs. The balance of the increase related to changes in other costs recoverable from customers.

### Property, Plant and Equipment

The increase of $45.6 million was comprised of the following items:

- additions from net capital expenditures of $97.6 million,
- additions of $1.1 million in capitalized financing costs that are non-cash in nature,
- additions of $0.4 million relating to the BTS asset under capital lease and $0.8 million relating to revised estimates of asset retirement costs were recorded, which were offset by equivalent increases in the BTS lease obligation and asset retirement obligation respectively, less
- a $9.7 million decrease in working capital relating to net capital expenditures,

- depreciation expense of $37.4 million,
- depreciation of $0.7 million relating to the BTS asset under capital lease and $0.6 million relating to asset retirement costs, the offsets of which have been recognized in regulatory assets, and
- contributions in aid of construction of $5.9 million received.

**Accounts Payable and Accrued Charges**

The decrease of $13.6 million was primarily due to a decrease in outstanding accounts payable relating to decreased capital expenditures and power purchase costs in the fourth quarter of 2011 compared to the same period in 2010.

**Current and Long-term Debt**

The increase of $15.9 million was primarily due to draws on bank credit facilities to finance capital expenditures.

**Future Income Taxes**

The increase of $9.1 million was primarily due to an increase in tax timing differences relating to capital expenditures, the offset of which has been recognized in regulatory assets.

**Retained Earnings**

The increase of $31.5 million was due to net earnings in the period of $47.5 million less dividends paid of $16.0 million.

## CAPITAL RESOURCES & LIQUIDITY

**Summary of Consolidated Cash Flows**

| Year Ended December 31 | **2011** | 2010 [1] | Variance |
|---|---|---|---|
| ($000s) | | | |
| **Cash, Beginning of Period** | **18** | 23 | (5) |
| **Cash Provided From (Used in)** | | | |
| Operating activities | **95,967** | 75,088 | 20,879 |
| Investing activities | **(95,410)** | (131,646) | 36,236 |
| Financing activities | **(571)** | 56,553 | (57,124) |
| **Cash, End of Period** | **4** | 18 | (14) |

[1] Certain comparative figures have been reclassified to comply with the current period's classification.

**Sources of Capital Resources and Liquidity**

FortisBC's primary sources of capital resources and liquidity include funds generated from operations, issuances of long-term debt, bank financing and operating lines of credit, and equity contributions from its ultimate parent Fortis.

**Operating Activities**

Cash provided by operating activities, which included the impact of changes in non-cash operating working capital, was $20.9 million higher in 2011 compared to 2010. The increase was primarily due to increases in net earnings, depreciation and amortization, less cash used in long-term regulatory assets and liabilities and changes in non-cash operating working capital.

**Investing Activities**

Cash used in investing activities, which included the impact of changes in investing working capital on net capital expenditures, was $36.2 million lower in 2011 compared to the same period in 2010. The decrease in cash used was primarily due to decreased capital expenditures, partially offset by a decrease in contributions in aid of construction received.

**Financing Activities**

Cash used in financing activities was $0.6 million in 2011, a decrease of $57.1 million compared to the $56.5 million of cash provided by financing activities during 2010. The cash used in investing activities during 2011 was funded by cash from operating activities and therefore required less cash to be provided by financing activities.

During 2011, the Corporation paid common share dividends of $16.0 million (2010 - $15.0 million) to its parent, FortisBC Pacific Holdings Inc. ("FortisBC Pacific"), which was offset by draws on credit facilities. During 2010, $56.5 million of cash was provided by financing activities, primarily through the November 24, 2010 issuance of $100.0 million of senior unsecured Medium Term Note ("MTN") Debentures Series 2, part of which was used to repay existing credit facilities at the time of issuance. While the Corporation issued common shares for proceeds of $10.0 million in 2010, there were no such issuances in 2011.

**Capital Structure**

FortisBC's business requires the Corporation to have ongoing access to capital to allow it to build and maintain the electrical systems in its service territory. In accordance with the BCUC's directives and to support investment grade credit ratings, the Corporation targets a long-term capital structure of 40 per cent equity and 60 per cent debt.

**Credit Ratings**

The following table discloses the Corporation's debenture ratings as of December 31, 2011.

| Rating Agency | Rating | Debt Rated |
|---|---|---|
| **DBRS** | A (low), Stable Trend | Secured and Unsecured Debentures |
| **Moody's Investors Service** | Baa1, Stable Outlook | Unsecured Debentures |

**Servicing and Repayment of Debt**

FortisBC has authorized bank credit facilities of $160.0 million, comprised of a $150.0 million operating credit facility and a $10.0 million demand overdraft facility. The operating credit facility is comprised of a $100.0 million three-year revolving facility maturing on May 7, 2014 ("Facility A") and a $50.0 million, 364-day revolving facility maturing on May 3, 2012 ("Facility B"). As of December 31, 2011, $142.5 million was available against the combined operating credit and demand overdraft facilities (December 31, 2010 - $158.8 million) and $nil (December 31, 2010 - $nil) was used to support outstanding letters of credit. Two years prior to the current Facility A maturity date, the Corporation may request an extension of the maturity date for Facility A for a further period of 364 days and if the request for extension is not granted, all amounts outstanding under Facility A become due on the Facility A maturity date. Similarly, prior to the current Facility B maturity date, the Corporation may request the lenders to extend the term for an additional 364 days and if the request for extension is not granted, Facility B will automatically convert into a non-revolving term credit facility that will mature six months from that date. The operating credit facility also allows the Corporation to request that the lenders provide up to $50.0 million of additional financing under Facility A or Facility B or a combination of the two facilities.

Borrowings under the Corporation's operating credit facilities bear interest at prime plus a margin or the certificate of deposit offered rate for bankers' acceptances plus a margin. The margin applied is based on FortisBC's debt ratings provided by its credit rating agencies. Borrowings under the overdraft facility bear interest at prime.

On November 19, 2010, FortisBC entered into an agreement to sell $100.0 million of senior unsecured MTN Debentures Series 2 which bear interest at a rate of 5.00 per cent to be paid semi-annually and mature on November 24, 2050. The closing of the issuance occurred on November 24, 2010, with net proceeds of $99.3 million being used to repay existing bank indebtedness and finance the capital expenditure program and working capital requirements.

FortisBC expects to meet interest payments on outstanding indebtedness from internally generated funds, but may have to rely upon the proceeds of new financings to meet its principal debt obligations when due.

### Capital Program

FortisBC's business is capital intensive and is focused on responding to customer growth and enhancing system reliability and safety through its capital program. Due to the size of the forecast capital program relative to the size of the Corporation, its implementation, financing and customer rate impacts present key challenges to the Corporation.

It is expected that capital expenditures in 2012 and beyond will be financed by drawing on the operating credit facility, utilizing the proceeds from future debt issues, equity contributions from the parent and from funds generated by operating activities.

During the year ended December 31, 2011, FortisBC spent $96.7 million on the capital program, net of $5.9 million of contributions in aid of construction received. The significant capital projects and related expenditures for the year ended December 31, 2011 were as follows: $15.1 million for the Generation Unit Life Extension program, $14.3 million for the Okanagan Transmission Reinforcement Project, and $10.5 million (net of $5.9 million of contributions in aid of construction received) relating to new distribution line extensions systems for customers.

As previously described in the "Regulation" section of this MD&A, the Corporation filed its 2012-2013 RRA, which included the 2012-2013 CEP, with the BCUC on June 30, 2011. The 2012-2013 CEP outlines capital expenditures necessary to provide service, public and employee safety and reliability of supply of electricity to the Corporation's growing customer base. The 2012-2013 CEP included capital expenditures of $111 million and $134 million before customer contributions, for 2012 and 2013 respectively. As part of the Evidentiary Update filed in November 2011 the forecast 2013 capital expenditures were reduced to $133 million.

The estimated capital expenditures for 2012 and 2013 are based on detailed forecasts of energy demand, weather, and cost of labour and materials, as well as other factors including economic conditions, which could change and cause actual expenditures to differ from forecasts.

FortisBC recovers capital costs through depreciation which is approved by the BCUC as part of the Corporation's revenue requirements application process. The BCUC also approves the CEPs of the Corporation. The BCUC may order a review of cost variances for individual projects prior to inclusion in rate base. In these situations, any variance in costs disallowed by the BCUC would be to the account of the shareholder.

## SHARE CAPITAL

FortisBC has issued and outstanding 2,018,510 common shares, all of which are owned by Fortis through its indirect wholly owned subsidiary, FortisBC Pacific.

During 2011, FortisBC issued nil common shares (2010 - 100,000 common shares) for cash consideration of $nil (2010 - $10.0 million).

During 2011, FortisBC paid dividends of $16.0 million (2010 - $15.0 million) to its parent company, FortisBC Pacific.

## CONTRACTUAL OBLIGATIONS

**Contractual Obligations – Payments Due by Period**

As at December 31, 2011

| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | After 5 Years |
|---|---|---|---|---|---|
| ($ millions) | | | | | |
| Power Purchases [1] | **5,334.6** | 47.4 | 85.3 | 161.0 | 5,040.9 |
| Interest on Long-term Debt | **805.9** | 38.9 | 74.5 | 57.9 | 634.6 |
| Debt Retirement [2] | **659.4** | 24.5 | 149.9 | 25.0 | 460.0 |
| Brilliant Terminal Station Agreement [3] | **87.1** | 3.2 | 6.4 | 6.5 | 71.0 |
| Defined Benefit Pension Funding Contributions [4] | **13.3** | 6.8 | 6.5 | - | - |
| Other [5] | **19.1** | 2.1 | 2.7 | 2.7 | 11.6 |
| Asset Retirement Obligations | **4.8** | 0.5 | 2.3 | 1.0 | 1.0 |
| **Totals** | **6,924.2** | **123.4** | **327.6** | **254.1** | **6,219.1** |

[1] Power purchase obligations of FortisBC include:

- the Brilliant Power Purchase Agreement (the "BPPA") - On May 3, 1996 an Order was granted by the BCUC approving the 60-year BPPA for the output of the Brilliant hydroelectric plant located near Castlegar, BC. The Brilliant plant is owned by the Brilliant Power Corporation ("BPC"), a corporation owned equally by the Columbia Power Corporation and the Columbia Basin Trust. FortisBC operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant, in exchange for the specified take-or-pay amounts of power. The BPPA includes a market related price adjustment after thirty years of the sixty year term.
- the BCH Power Purchase Agreement - The Corporation has a power purchase agreement with BCH which expires in 2013 and provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a 5-year rolling nomination of the capacity requirements.
- the Powerex Capacity Agreement - During September 2010, FortisBC entered into an agreement to purchase fixed price, winter capacity purchases through to February 2016 from Powerex Corp., a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC brings any new resources, such as capital or contractual projects, on-line prior to the expiry of this agreement, FortisBC may terminate this contract any time after July 1, 2013 with a minimum of three months written notice to Powerex Corp. Additionally, in November 2011, FortisBC entered into a second agreement to purchase fixed price, winter capacity purchases through to March 2012 from Powerex Corp.
- the Waneta Expansion Capacity Agreement (the "WECA") - FortisBC has entered into an agreement made as of October 1, 2010 to purchase capacity from the Waneta Expansion, a 335 MW hydroelectric generating facility currently under construction adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership, the limited partners of which are FortisBC's ultimate parent, Fortis, which owns a 51 per cent interest, and a wholly-owned subsidiary of each of Columbia Power Corporation and Columbia Basin Trust. It allows FortisBC to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in 2015. The form of the WECA was originally accepted for filing by the BCUC on September 23, 2010 and an executed version of the WECA was submitted to the BCUC on November 18, 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of filing of the executed WECA.

[2] Excludes debt issue costs.

[3] On July 15, 2003, the Corporation began operating the Brilliant Terminal Station ("BTS") under an agreement the term of which expires in 2056. The agreement provides that FortisBC will pay the owners a charge related to the recovery of the capital cost of the BTS and related operating costs. FortisBC has accounted for this arrangement as a capital lease asset and obligation in its financial statements.

[4] The Corporation sponsors three contributory defined benefit pension plans, one of which is closed to new entrants. Under the terms of these plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations which were dated December 31, 2010.

[5] Included in other contractual obligations are building leases, vehicle leases, and a commitment to purchase fibre optic communication cable for approximately $2.5 million in 2019.

## RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, ultimate parent and other related companies under common control. The following transactions were measured at the exchange amount unless otherwise indicated:

| Year Ended December 31 | **2011** | 2010 [1] |
|---|---|---|
| ($000s) | | |
| Revenue charged to related parties | **1,922** | 1,652 |
| Operating costs charged by related parties | **3,845** | 2,169 |
| Operating costs recovered from related parties | **8,783** | 6,181 |
| Interest revenue on accounts receivable | **28** | 20 |
| Capital costs charged from related parties | **35** | 550 |

[1] Certain comparative figures have been reclassified to comply with the current period's classification.

The revenues charged represent electricity and services sold to related parties.

The operating costs charged consist of contract and direct labour charges, meter shop charges, rent, natural gas utility charges consumed in operating the Corporation's facilities, corporate governance costs and information technology expenses. In addition, Fortis is authorized to grant certain key employees of FortisBC options to purchase shares of Fortis. For the year ended December 31, 2011, compensation expense relating to stock options of $0.5 million (2010 - $0.5 million) was included in operating costs charged by related parties.

The operating costs recovered consist of labour and materials charges to the Corporation's parent and other related parties.

Included in accounts receivable are amounts due from officers of the Corporation relating to share purchase loans, some of which are non-interest bearing and due within one year from the grant date, and some of which bear interest equal to the amount of the dividends received on the shares and are due within 10 years of the grant date or within one year following cessation of employment, whichever occurs first. Also included in accounts receivable are amounts due from FortisBC Pacific which bear interest at prime. Interest on the related party accounts receivable was recorded in other revenue.

Capital costs charged consist of purchasing electrical equipment from a related Fortis subsidiary and the 2010 purchase of land at the carrying amount from the Corporation's parent.

Inter-corporate charges between FortisBC and other related companies under common control are included in accounts receivable and accounts payable and are unsecured and due on demand.

Amounts due to and from the Corporation's parent, ultimate parent and other related companies under common control and officers of the Corporation are as follows:

| | **2011** | 2010 |
|---|---|---|
| ($000s) | | |
| Included in accounts receivable | **863** | 809 |
| Included in accounts payable and accrued charges | **887** | 313 |

## SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth audited financial information for the years ended December 31, 2011, 2010 and 2009. The financial information has been prepared in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for companies not subject to rate regulation. These results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

| Year Ended December 31 | **2011** | 2010 [2] | 2009 [2] |
|---|---|---|---|
| ($000s) | | | |
| Revenues | **283,948** | 259,711 | 245,952 |
| Net Earnings | **47,498** | 41,760 | 36,224 |
| Total Assets | **1,326,046** | 1,271,441 | 1,147,172 |
| Current and Long-term Debt [1] | **659,421** | 643,992 | 581,497 |
| Dividends | **16,000** | 15,000 | 14,500 |

[1] Debt issue costs of $5.6 million in 2011, $6.0 million in 2010 and, $5.4 million in 2009 have been excluded from current and long-term debt.

[2] Certain comparative figures have been reclassified to comply with the current period's classification.

The increase in revenues and earnings over the three years was primarily due to customer growth and rate increases each year.

The increases in total assets and current and long-term debt was primarily due to the capital expenditures in each of the three years.

## QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2010 through December 31, 2011. The information has been obtained from the Corporation's unaudited interim consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected for companies not subject to rate regulation. Past operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

| Quarter Ended | **Electricity Revenue** | **Net Earnings** |
|---|---|---|
| ($000s) | | |
| December 31, 2011 | 75,621 | 10,532 |
| September 30, 2011 | 63,840 | 9,496 |
| June 30, 2011 | 60,513 | 8,946 |
| March 31, 2011 | 79,434 | 18,524 |
| December 31, 2010 | 70,406 | 9,786 |
| September 30, 2010 | 57,663 | 10,492 |
| June 30, 2010 | 54,712 | 8,176 |
| March 31, 2010 | 66,040 | 13,306 |

A summary of the past eight quarters reflects FortisBC's growth as well as the seasonality associated with the Corporation's business. The operations generally produce higher earnings in the first quarter of the fiscal year due to increased customer load as a result of cooler weather, while certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year.

**March 2010/2011** - The increase in electricity revenue and earnings was primarily due to a 6.6 per cent rate increase effective January 1, 2011 and reduced electricity sales in the first quarter of 2010 due to warm temperatures.

**June 2010/2011 -** The increase in electricity revenue and earnings was primarily due to a 6.6 per cent rate increase effective January 1, 2011.

**September 2010/2011** - The increase in electricity revenue was primarily due to a 6.6 per cent rate increase effective January 1, 2011. The decrease in earnings was primarily due to higher income taxes and a decrease in capitalized financing costs, partially offset by the 6.6 per cent rate increase effective January 1, 2011.

**December 2010/2011** - The increase in electricity revenue and earnings was primarily due to a 6.6 per cent rate increase effective January 1, 2011.

## FOURTH QUARTER RESULTS

### Consolidated Financial Results

| Quarter Ended December 31 | **2011** | 2010 [3] | Variance |
|---|---|---|---|
| **Electricity Sales** (GWh) | **849** | 854 | (5) |
| ($000s) | | | |
| Electricity Revenue | **75,621** | 70,406 | 5,215 |
| Other Revenue [1] | **2,258** | 1,608 | 650 |
| Power Purchase Costs | **22,496** | 23,321 | (825) |
| Operating Costs | **21,763** | 18,533 | 3,230 |
| Depreciation and Amortization | **11,382** | 10,402 | 980 |
| Finance Charges [2] | **9,930** | 9,040 | 890 |
| Income Taxes | **1,776** | 932 | 844 |
| **Net Earnings** | **10,532** | 9,786 | 746 |

[1] Includes equity component of allowance for funds used during construction (capitalized financing costs).

[2] Net of debt component of allowance for funds used during construction (capitalized financing costs).

[3] Certain comparative figures have been reclassified to comply with the current period's classification.

Net earnings for the three months ended December 31, 2011 were $10.5 million, an increase of $0.7 million from the $9.8 million of net earnings for the same period of 2010. As approved by the BCUC, electricity rates reflected an allowed ROE of 9.90 per cent and a deemed equity component of capital structure of 40 per cent.

The increase in net earnings for the three months ended December 31, 2011 over the comparable period for 2010 was primarily due to:

- the 6.6 per cent rate increase effective January 1, 2011 driven primarily by ongoing investment in infrastructure,

partially offset by

- a decrease in allowance for funds used during construction (capitalized financing costs) as a result of less assets under construction during the period, and
- the variances between the actual results for the three months ended December 31 2011 as compared to the forecast for the three months ended December 31, 2011 used to set rates in establishing the 6.6 per cent customer rate increase. These variances primarily consisted of a decrease in electricity

revenue and an increase in operating costs, partially offset by a decrease in power purchase costs, the aggregate which resulted in lower incentives owing back to customers as these variances are shared equally between customers and FortisBC as previously described in "Regulation" and "Other Revenue".

**Electricity Sales**

Electricity sales were comparable to the same period of 2010 as unfavourable weather conditions were mostly offset by customer growth.

**Electricity Revenue**

The increase in electricity revenue was primarily due to a 6.6 per cent rate increase effective January 1, 2011 and a 1.4 per cent rate increase effective June 1, 2011, partially offset by a decrease in electricity sales.

**Other Revenue**

The increase in other revenue was primarily due to a decrease in PBR incentive adjustments to be refunded to customers and increased wheeling revenue, partially offset by a decrease in the equity component of allowance for funds used during construction.

**Power Purchase Costs**

The decrease in power purchase costs was primarily due to lower average power purchase prices as well as decreased electricity sales.

**Operating Costs**

The increase in operating costs was primarily due to an additional $1.8 million in operating and maintenance costs primarily relating to vegetation management as approved by the BCUC, the timing of incurring operating and maintenance costs, as well as increased labour escalations, general inflationary increases, increased property taxes and wheeling expenses, partially offset by an increase in capitalized overhead.

**Depreciation and Amortization**

The increase in depreciation and amortization was primarily due to the increase in the depreciable asset base resulting from the Corporation's capital expenditure program.

**Finance Charges**

The increase in finance charges was primarily due to an increase in borrowings to finance the capital expenditure program and a decrease in the debt component of allowance for funds used during construction (capitalized financing costs).

**Income Taxes**

The increase in income tax expense for the quarter was primarily due to an increase in earnings before income taxes and lower income tax timing differences as compared to the same period in 2010, partially offset by a reduction in the combined Federal and Provincial income tax rates.

## OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2011, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

## FINANCIAL INSTRUMENTS

### Designation and Valuation of Financial Instruments

The Corporation enters into financial instruments to finance the Corporation's operations in the normal course of business.

The carrying values of the Corporation's financial instruments compared to their fair values are as follows:

| | December 31, 2011 | | December 31, 2010[6] | |
|---|---|---|---|---|
| | **Carrying Value** | **Estimated Fair Value** | Carrying Value | Estimated Fair Value |
| ($000s) | | | | |
| **Held for trading** | | | | |
| Cash[1] | **4** | **4** | 18 | 18 |
| **Loans and receivables** | | | | |
| Accounts receivable[1,2] | **39,415** | **39,415** | 45,843 | 45,843 |
| Energy management loans[1,2] | **2,447** | **2,447** | 3,208 | 3,208 |
| **Other financial liabilities** | | | | |
| Accounts payable and accrued charges[1,2] | **41,149** | **41,149** | 54,769 | 54,769 |
| Operating credit and overdraft facilities[1,2] | **17,478** | **17,478** | 1,122 | 1,122 |
| Long-term debt, including current portion[3,4,5] | **641,943** | **797,541** | 642,870 | 725,224 |

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

2 Carrying values approximate amortized cost.

3 Includes secured and unsecured debentures and mortgage obligations for which the carrying value is measured at amortized cost using the effective interest method.

4 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at the measurement date or by using quoted market sources.

5 Excludes deferred financing costs of $5.6 million at December 31, 2011 (December 31, 2010 - $6.0 million).

6 Certain comparative figures have been reclassified to comply with the current period's classification.

### Risks

Exposure to credit risk, foreign exchange risk, interest rate risk, and liquidity risk occur in the normal course of the Corporation's operations. The Corporation currently does not enter into derivative financial instruments to reduce exposure to fluctuations in any of the risks impacting the Corporation's operations.

*Credit Risk*

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and cash equivalents, accounts receivable and energy management loans, the Corporation's exposure to credit risk is limited to the carrying value on the balance sheet.

The Corporation extends credit to customers in its role as a regulated electric utility service provider. Credit risk on accounts receivable is managed based on the terms and conditions of the Electric Tariff BCUC No.1 for Service in the West Kootenay and Okanagan Areas. The Corporation manages credit risk for its accounts receivable by requiring customer deposits or credit checks for new customers and by issuing notices, performing disconnections and using third party collection agencies for overdue accounts. The Corporation's credit risk is also mitigated through revenue requirements applications to the BCUC which includes a forecast amount for uncollectible accounts receivable.

At December 31, 2011 the balance of customer accounts receivable past due over 60 days was $0.9 million (December 31, 2010 - $1.0 million). The Corporation has provided an allowance for doubtful accounts of $1.0 million (December 31, 2010 - $1.1 million) on outstanding accounts receivable.

*Foreign Exchange Risk*

Foreign exchange risk is the risk that the value of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation realizes all of its sales and a significant majority of its expenses in Canadian dollars and is therefore not exposed to significant foreign exchange rate fluctuations.

*Interest Rate Risk*

Interest rate risk is the risk that the value of a financial instrument will fluctuate due to changes in market interest rates. The Corporation's secured and unsecured debentures bear fixed interest rates, while the Corporation's operating credit facility and overdraft facility are subject to variable interest rates. Under the PBR regulatory framework that the Corporation operated within until the end of 2011, any variations in regulated interest expense were flowed through to be paid by or returned to customers in future customer rates. Due to this regulatory mechanism, the Corporation's exposure to interest rate risk on its variable interest rate debt was mitigated.

*Liquidity Risk*

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation has secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. FortisBC has authorized bank credit facilities of $160.0 million, comprised of a $150.0 million operating credit facility and a $10.0 million unsecured demand overdraft facility as previously discussed in "Servicing and Repayment of Debt".

## CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the periods. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated. Any such adjustments, which could be material, will be recorded in the period they become known.

### Regulation

Generally, the accounting policies of the Corporation's regulated operations are subject to examination and approval by the regulatory authority, the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authority for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known.

As at December 31, 2011, the Corporation recorded $134.9 million in current and long-term regulatory assets (December 31, 2010 - $119.6 million) and $8.0 million in current and long-term regulatory liabilities (December 31, 2010 - $3.9 million).

**Depreciation and Amortization**

Depreciation of property, plant and equipment and amortization of intangible assets, by their nature, are an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2011, the Corporation's property, plant and equipment and intangible assets were $1,135.7 million, or approximately 86 per cent of total consolidated assets, compared to property, plant and equipment and intangible assets of $1,090.2 million, or approximately 86 per cent of total consolidated assets, as at December 31, 2010. Changes in depreciation and amortization rates can have a significant impact on the Corporation's depreciation and amortization expense.

As part of the customer-rate setting process, appropriate depreciation and amortization rates are approved by the BCUC. The depreciation and amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed and based on the results of these depreciation studies, the impact of any over or under depreciation and amortization as a result of actual experience differing from that expected and provided for in previous depreciation and amortization rates is generally reflected in future depreciation and amortization rates and expense, and such differences are reflected in future customer rates.

**Capitalized Overhead**

As required by the BCUC, the Corporation capitalizes overhead costs that may not be directly attributable to specific items of property, plant and equipment and intangible assets, but which relate to the overall CEP. These capitalized overheads are allocated over constructed property, plant and equipment and intangible assets and are amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to property, plant and equipment and intangible assets is established by the BCUC. In 2011, capitalized overhead totaled $10.8 million (2010 - $9.5 million). Any change in the methodology of calculating and allocating general overhead costs to property, plant and equipment and intangible assets could have a significant impact on the amount recorded as operating expenses and property, plant and equipment and intangible assets.

**Employee Future Benefits**

The Corporation's defined benefit pension plans and supplemental pension arrangements and Other Post Employment Benefits ("OPEB") plan are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining net benefit cost and obligation are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating pension net benefit cost for 2011, is 6.75 per cent, down from the 7.00 per cent assumed long-term rate of return used for 2010. As two of the Corporation's defined benefit pension plans have excess interest indexing provisions, which provide that a portion of investment returns are allocated to provide for indexing of pension benefits, the accrued benefit obligations may vary based on the expected long-term rate of return on plan assets.

The assumed discount rate, used to measure the Corporation's accrued pension benefit obligations on the applicable measurement date in 2011 was 4.50 per cent, down from 5.00 per cent used in 2010. These discount rates reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. The decrease in discount rates reflects the decreased credit spreads and cost of capital on investment grade corporate bonds. As the Canadian GAAP measurement date for the Corporation's defined benefit pension plans and supplemental pension arrangements and OPEB plans is September 30, 2011, any impact of capital market changes on credit spreads through the remainder of 2011 would not be reflected in the assumed discount rate of 4.50 per cent for determining the accrued pension and OPEB benefit obligations.

The long-term rate of return is based on the expected average return of the assets over a long period given the relative asset mix. The discount rate is determined with reference to the current market rate of interest on high quality debt instruments with cash flows that match the time and amount of expected benefit payments.

FortisBC expects its 2012 net benefit cost for defined benefit pension plans, which will be determined under US GAAP and measured at December 31, 2011, to be approximately $1.7 million higher than the 2011 net benefit cost determined under Canadian GAAP. The higher 2012 pension net benefit cost is primarily due to the effect of the decrease in the discount rate from 5.00 per cent to 4.25 per cent and lower than expected investment returns, partially offset by the elimination of the transitional obligation in transitioning from Canadian GAAP to US GAAP.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on plan assets and discount rate on 2011 net benefit cost and the accrued benefit pension asset recorded in the Corporation's financial statements, as well as the impact on the accrued pension benefit obligation.

| | **Year Ended December 31, 2011** | **As at December 31, 2011** | |
|---|---|---|---|
| | **Net Benefit Cost** | **Net Accrued Benefit Asset** | **Accrued Benefit Obligation** |
| **Increase (Decrease) / $ millions** | | | |
| Impact of increasing the rate of return on plan assets assumption used during 2011 by 1.0% | (1.0) | 1.0 | 1.7 |
| Impact of decreasing the rate of return on plan assets assumption used during 2011 by 1.0% | 1.0 | (1.0) | (5.6) |
| Impact of increasing the discount rate assumption used during 2011 by 1.0% | (2.3) | 2.3 | (24.2) |
| Impact of decreasing the discount rate assumption used during 2011 by 1.0% | 2.9 | (2.9) | 30.5 |

The above table reflects the changes before the effect of any regulatory deferral mechanism approved by the BCUC.

Other assumptions applied in measuring pension net benefit cost and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Corporation's OPEB plan is also subject to judgments utilized in the actuarial determination of the OPEB net benefit cost and related accrued benefit obligation. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions, along with health care cost trends, were also utilized by management in determining OPEB plan net benefit cost and accrued benefit obligation.

As at December 31, 2011, the Corporation had a consolidated pension accrued benefit asset of $7.0 million (December 31, 2010 - $7.4 million) and an OPEB accrued benefit liability of $16.7 million

(December 31, 2010 - $14.1 million). During 2011, the Corporation recorded consolidated pension and OPEB net benefit cost of $10.1 million (2010 - $8.0 million).

**Asset Retirement Obligation ("ARO")**

FortisBC has recorded an ARO associated with the removal of polychlorinated biphenyls ("PCB") contaminated oil from its electrical equipment. AROs are legal obligations associated with the retirement of long-lived assets. A liability is recorded in the period in which the obligation can be reasonably estimated at the present value of the estimated fair value of the future costs. The determination of the ARO depends upon management's best estimates relating to factors such as timing, amount and nature of future cash flows necessary to discharge the legal obligation and comply with existing legislation or regulations, as well as the use of a credit-adjusted risk-free rate for measurement purposes. There are uncertainties in estimating future asset retirement costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. It is possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Corporation's current assumptions. In addition, in order to remove certain PCB-contaminated oil, the ability to take maintenance outages in critical facilities may impact the timing of expenditures. The ARO may change from period to period because of the changes in the estimation of these uncertainties.

**Revenue Recognition**

The Corporation recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated electricity sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2011, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $15.1 million (December 31, 2010 - $17.8 million) on annual electricity revenues of $279.4 million (2010 - $248.8 million).

**Income Taxes**

Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of future income taxes resulting from temporary differences between the carrying value of assets and liabilities in the financial statements and their tax values. A future income tax asset or liability is determined for each temporary difference based on the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. Future income tax assets are assessed for the likelihood that they will be recovered from future taxable income. Estimates of the provision for income taxes and future income tax assets and liabilities might vary from actual amounts incurred.

**Contingencies**

The Corporation is subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial position or results of operations. Contingencies are described in the "Business Risk Management" of this MD&A.

## NEW ACCOUNTING POLICIES

**Business Combinations**

In January 2009, Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-Controlling Interests* were issued. These new standards are effective for fiscal years beginning on or after January 1, 2011. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have an impact on the Corporation's net earnings or consolidated balance sheet in the current period but will affect the recognition of business combinations completed by the Corporation in the future.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of sections 1601 and 1602 did not have an impact on the Corporation's net earnings or consolidated balance sheet in the current period but may affect the recognition of business combinations completed by the Corporation in the future.

## FUTURE ACCOUNTING CHANGES

**Adoption of New Accounting Standards**

Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board, FortisBC has evaluated the option of adopting US GAAP, as opposed to International Financial Reporting Standards ("IFRS"), and has decided to adopt US GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a United States Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation, in coordination with its ultimate parent Fortis, filed an application with the Ontario Securities Commission ("OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit FortisBC to prepare financial statements in accordance with US GAAP without qualifying as an SEC Issuer ("the Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently relies primarily on US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. FortisBC believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

During the fourth quarter of 2010, the Corporation developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

*Phase I - Scoping and Diagnostics*: Phase I consisted of project initiation and awareness; project planning and resourcing; and identification of high-level differences between US GAAP and Canadian GAAP in order to highlight areas where detailed analysis would be needed to determine and conclude as to the nature and extent of financial statement impacts. External accounting and legal advisors were engaged during this phase to assist the Corporation's internal US GAAP conversion team and to provide technical input and expertise as required. Phase I commenced in the fourth quarter of 2010 and was completed during 2011.

*Phase II - Analysis and Development*: Phase II consists of detailed diagnostics and evaluation of the financial statement impacts of adopting US GAAP based on the high-level assessment conducted under Phase I; identification and design of any new, or changes to, operational or financial business processes; initial staff training and audit committee orientation; and development of required solutions to address identified issues.

Phase II had included planned activities for the registration of securities as required to achieve SEC Issuer status and an assessment of ongoing requirements of the United States *Sarbanes-Oxley Act* ("US SOX"), including auditor attestation of internal controls over financial reporting, and a comparison of the requirements under US SOX to those required in Canada under National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. These activities are no longer required or applicable as a result of the Exemption granted by the OSC as discussed above.

Phase II of the plan commenced in January 2011 and was essentially completed during 2011. Based on the research and analysis completed to date, and the Corporation's continued ability to apply rate-regulated accounting policies under US GAAP, the differences between US GAAP and Canadian GAAP are not expected to have a material impact on consolidated earnings and are expected to be mostly limited to changes on the balance sheet and additional disclosure requirements. The impact on information systems and internal controls over financial reporting is expected to be minimal.

*Phase III - Implementation and Review*: Phase III is currently ongoing and has involved the implementation of financial reporting systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements in accordance with US GAAP beginning in 2012, and the communication of associated impacts.

The Corporation will prepare and file its annual audited Canadian GAAP consolidated financial statements for the year ending December 31, 2011 in the usual manner. The Corporation then intends to voluntarily prepare and file annual audited US GAAP consolidated financial statements for the year ending December 31, 2011, with 2010 comparatives. The Corporation's voluntary filing of annual audited US GAAP consolidated financial statements for the year ending December 31, 2011, subsequent to the filing of its annual audited Canadian GAAP consolidated financial statements for the year ending December 31, 2011, has been approved by the OSC and is expected to be completed by March 31, 2012. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared and filed in accordance with US GAAP.

Phase III will conclude when the Corporation files its annual audited consolidated financial statements for the year ending December 31, 2012 prepared in accordance with US GAAP.

**Financial Statement Impacts - US GAAP:** The areas identified to date where differences between US GAAP and Canadian GAAP are expected to have the most significant financial statement impacts are outlined below. The identified impacts are unaudited and are subject to change based on further analysis.

***Employee future benefits:*** Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit pension plans and other post-retirement benefits is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded or unfunded status being disclosed in the notes to the consolidated financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains and losses and transitional obligations or assets which have not yet been recognized.

US GAAP requires recognition of the funded or unfunded status of defined benefit pension plans and other post-retirement benefits on the balance sheet. Unamortized balances related to past service costs, actuarial gains and losses and transitional obligations are separately recognized on the balance sheet as a component of accumulated other comprehensive income or, in the case of entities with activities subject to rate regulation, as regulatory assets or liabilities for recovery from, or refund to, customers in future rates. Subsequent changes to past service costs, actuarial gains and losses and transitional obligations would be recognized as part of net benefit cost, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation will recognize the funded or unfunded status of its defined benefit pension plans and other post-retirement benefits on the balance sheet with the above noted unamortized balances recognized as regulatory assets or liabilities.

Additional differences between Canadian GAAP and US GAAP in terms of accounting for defined benefit pension plans and other post-retirement benefits include a change in the measurement date and the determination of the attribution period over which net benefit cost is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end, however, US GAAP requires the entity's fiscal year end to be used as the measurement date. As a result, the Corporation will be changing its measurement date of September 30 under Canadian GAAP to December 31 under US GAAP. Canadian GAAP also allows for the use of an attribution period for defined benefit pension plans, under specific circumstances, that extend beyond the date when the credited service period ends. However, US GAAP allows for the use of an attribution period for defined benefit pension plans up to the date when credited service ends.

The above differences are expected to impact the Corporation's employee future benefits obligation, which will be offset by a corresponding change to regulatory assets or liabilities.

The impact of adopting US GAAP with respect to accounting for employee future benefits (i.e., defined benefit pension plans and other post-retirement benefits) is not expected to have a material impact on the Corporation's consolidated earnings.

***Brilliant Power Purchase Agreement ("BPPA"):*** FortisBC expects that the BPPA will be accounted for as a capital lease under US GAAP. While the requirement to evaluate whether an arrangement includes a lease is similar between Canadian GAAP and US GAAP, the effective date for prospective adoption of lease accounting guidance differs, resulting in an accounting difference with respect to the BPPA.

Fulfillment of the BPPA is dependent on the use of a specific asset, the Brilliant Hydroelectric Plant ("Brilliant"), and the conveyance unto FortisBC the right to use that asset under an arrangement between FortisBC and the legal owner of Brilliant. The BPPA qualifies as a capital lease as the present value of the minimum lease payments to be made by FortisBC represents recovery of the entire amount of the initial investment in Brilliant by the legal owner over the term of the arrangement.

The anticipated effect of retrospectively recognizing Brilliant as a capital lease upon adoption of US GAAP includes the recognition of a capital lease asset with an offsetting capital lease obligation for an equivalent amount. Each subsequent reporting period, the total amount of depreciation and interest expense to be recognized under capital lease accounting is expected to differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the BCUC. This timing difference is expected to be recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA.

Since US GAAP allows for entities to account for the effects of rate regulation, the impact of adopting capital lease accounting for Brilliant is not expected to affect the Corporation's consolidated earnings.

***Push-down Accounting:*** Push-down accounting refers to the establishment of a new accounting basis for an acquired entity in its separate standalone financial statements based on an acquisition that results in the acquired entity's outstanding shares becoming substantially wholly owned.

On May 31, 2004, Fortis acquired FortisBC and accounted for the acquisition using the purchase method, whereby the regulated book value of assets and liabilities acquired were assigned as fair value for the purchase price allocation. Total goodwill associated with FortisBC on acquisition has been included on the balance sheet of Fortis under Canadian GAAP.

As the application of push-down accounting effectively results in the creation of a new accounting entity, the acquired entity's operating results prior to push-down accounting are not combined with those subsequent to push-down accounting. Therefore, the Corporation expects that its retained earnings at the date of acquisition will be reset to zero with an offset to contributed surplus, a component of shareholder's equity. Additionally, it is expected that any fair value adjustments and goodwill associated with the acquisition by Fortis on May 31, 2004 will be recognized in the financial statements of FortisBC with an offset to contributed surplus.

The above items do not represent a complete list of expected differences between US GAAP and Canadian GAAP, and are subject to change. Other less significant differences have also been identified. Analysis also remains ongoing and additional areas where the Corporation's consolidated financial statements could be materially impacted may be identified prior to the Corporation's voluntary preparation and filing of its annual audited US GAAP consolidated financial statements for the year ending December 31, 2011. A detailed reconciliation between the Corporation's audited Canadian GAAP and US GAAP financial statements for 2011, including 2010 comparatives will be disclosed as part of that voluntary filing.

The unaudited, estimated quantification and reconciliation of the Corporation's consolidated balance sheet as December 31, 2010 prepared in accordance with US GAAP versus Canadian GAAP, based on the differences identified to date, may be summarized as follows:

Total assets as of December 31, 2010 are estimated to increase by approximately $529 million. The estimated increase is due primarily to expected increases in regulatory assets, property, plant and equipment and goodwill in accordance with US GAAP.

Total liabilities as of December 31, 2010 are estimated to increase by approximately $309 million. The estimated increase is due primarily to the expected increases in capital lease obligations and defined benefit pension plans and other post-retirement benefits liabilities in accordance with US GAAP.

Shareholder's equity as of December 31, 2010 is estimated to increase by approximately $220 million. The estimated increase is due primarily to the effects of push-down accounting in accordance with US GAAP.

As previously indicated, no material adjustments to the Corporation's consolidated earnings are currently expected under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The quantification and reconciliation of the Corporation's consolidated financial statements from Canadian GAAP to US GAAP for the 2011 annual reporting period is expected to be completed by March 31, 2012.

***US GAAP Application***

In February 2011, FortisBC and the FortisBC Energy companies (comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.) filed an application with the BCUC to adopt US GAAP for regulatory reporting purposes effective January 1, 2012. FortisBC and the FortisBC Energy companies received a decision in July 2011 whereby the BCUC has approved the request effective January 1, 2012 to December 31, 2014. As outlined in the decision, by September 1, 2014, FortisBC and the FortisBC Energy companies are to apply to the BCUC for approval of the accounting standard to be used for regulatory reporting purposes effective January 1, 2015.

## BUSINESS OUTLOOK

### The BC Energy Plan and Clean Energy Act

The British Columbia provincial government released its Energy Plan on February 27, 2007. The plan is a natural progression from the previous plan with a strong focus on environmental leadership, energy conservation and efficiency, and investment in innovation. Many of the principles of the Energy Plan were incorporated into the BC regulatory framework upon the British Columbia Legislature amending the *Utilities Commission Amendment Act in 2008* and passing the *Clean Energy Act*. The *Clean Energy Act,* which establishes a long-term vision for the province as a leader in clean energy development came into force on June 3, 2010. Specifically, the *Clean Energy Act* outlines 16 energy objectives for British Columbia, including the objective to have 93 per cent of British Columbia's electricity generated by clean or renewable resources; to take demand-side measures and to conserve energy to meet a minimum of 66 per cent of the expected increase in BCH's demand for electricity by the year 2020; and to become a net exporter of electricity generated from clean or renewable resources. The Corporation will continue to assess the impact of the *Clean Energy Act* on its business.

### Collective Agreements

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expires on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation, transmission and distribution.

The collective agreement between the Corporation and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired January 31, 2011. During 2011, discussions between the parties focused on the renegotiation of the FortisBC COPE agreement. An agreement has been reached with regard to certain customer service employees. Discussions continue with regard to the remaining FortisBC COPE bargaining unit.

### Regulatory

The Corporation would expect earnings to grow in future years assuming a consistently applied regulated capital structure, no material reduction in the allowed ROE, recovery of its cost-of-service components in rates, and growth in rate base assets as a result of its annual capital expenditures.

## BUSINESS RISK MANAGEMENT

The Corporation is subject to a variety of risks and uncertainties that may have material and adverse effects, financial or otherwise, on the results of the Corporation's operations.

### Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. The ability of the Corporation to recover the actual costs of providing services and to earn the approved rates of return is impacted by achieving the forecasts established in the rate-setting process. The cost for upgrading existing facilities and adding new facilities requires the approval of the BCUC for inclusion in the rate base. There is no assurance that capital projects perceived as required by the management of the Corporation will be approved or that conditions to such approval will not be imposed. Capital cost overruns might not be recoverable in rates.

Through the regulatory process, the BCUC approves the ROE that the Corporation is allowed to earn and the deemed capital structure. Fair regulatory treatment that allows the Corporation to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as ongoing capital attraction and growth. There can be no assurance that the rate orders issued by the BCUC will permit the Corporation to recover all costs actually incurred and to earn the expected or fair rate of return or appropriate capitalization.

Rate applications that reflect cost of service and establish revenue requirements may be subject to negotiated settlement procedures in British Columbia. Failing a negotiated settlement, rate applications may be pursued through a public hearing process. BCUC approval of rates for 2012, and for future years, will be required. There can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the expected rate of return.

A failure to obtain rates or appropriate ROE and capital structure as applied for may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed upgrades or expansion projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, negatively impact the Corporation's results of operations or financial position.

**Transition to New Accounting Standards**

The Corporation has adopted US GAAP, as opposed to IFRS, effective January 1, 2012. The transition to US GAAP is described in this MD&A under "Future Accounting Changes".

On June 9, 2011 the OSC issued a decision granting the Corporation an Exemption to permit the Corporation to prepare their financial statements in accordance with US GAAP without qualifying as an SEC Issuer pursuant to Canadian securities laws. Further, in July of 2011 the BCUC approved the Corporation's request to adopt US GAAP for regulatory purposes for the period from January 1, 2012 to December 31, 2014. Accordingly, the Corporation will prepare financial statements in accordance with US GAAP beginning on January 1, 2012.

If the Corporation's Exemption from the OSC and subsequent approval by the BCUC do not continue past December 31, 2014 then the Corporation will be required to become an SEC Issuer or adopt IFRS effective January 1, 2015. If the Corporation does not qualify as an SEC Issuer or is otherwise required to adopt IFRS, then in the absence of an accounting standard for rate-regulated activities this could result in increased volatility in the Corporation's consolidated earnings from that otherwise recognized under US GAAP.

**Equipment Breakdown, Operating and Maintenance Risk**

The Corporation's assets require ongoing maintenance, improvement and replacement. Accordingly, in order to ensure the continued performance of the Corporation's physical assets, the Corporation determines expenditures that must be made to maintain and replace assets. The Corporation could experience service disruptions and increased costs if it is unable to maintain its asset base. The inability to recover, through approved rates, capital expenditures that the Corporation believes are necessary to maintain, improve, replace and remove its assets, the failure by the Corporation to properly implement or complete approved capital expenditure programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Corporation.

The Corporation continually updates its capital expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation of its business. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulatory-approved capital expenditures, it is uncertain as to whether such additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the Corporation.

**Environmental Matters**

The Corporation is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety, for which the Corporation incurs compliance costs. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events, including severe weather and other natural disasters, human error or misconduct or equipment failure. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material effect on the business, results of operations, financial condition and prospects of the Corporation.

The Corporation is exposed to environmental risks that owners and operators of properties in British Columbia generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. It is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Corporation.

Although most of the Corporation's generating and transmission facilities have been in place for many years with no apparent adverse environmental impact, environmental assessments and approvals may be required in the ordinary course of business for existing and future facilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, on which the Corporation's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at the Corporation's plants or at plants operated by parties contracted to supply energy to the Corporation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and conducting environmental impact assessments and remediation. It is possible that other developments may lead to increasingly strict environmental and safety laws, regulations and enforcement policies and claims for damages to property or persons resulting from the Corporation's operations, any one of which could result in substantial costs or liabilities to the Corporation. Any regulatory changes that impose additional environmental restrictions or requirements on the Corporation or its customers could adversely affect the Corporation through increased operating and capital costs.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electro-magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electro-magnetic fields present a health hazard, litigation could result and the Corporation could be required to take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures could be material.

Spills and leaks can occur in the operation of electricity transmission facilities, including, primarily, accumulations of oil containing hydrocarbons and PCB contaminants in soil and gravel at substation sites. The Corporation remediates such sites in accordance with environmental regulations and standards and sound industry practice. There can be no assurance that the Corporation will not be obligated to incur further expenses in connection with changes in environmental regulations and standards or as a result of historical contamination.

Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line or lightning strikes to wooden poles. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third party facilities located near the land on which the transmission facilities are situate. The Corporation may be liable for fire-fighting costs and third party claims in connection with fires on these or other lands on which its transmission facilities are located, and such claims, if successful, could have a material effect on the business, results of operations and prospects of the Corporation.

Electricity transmission and distribution has inherent potential risks and there can be no assurance that substantial costs and liabilities will not be incurred. Potential environmental damage and costs could materialize due to some type of severe weather event or major equipment failure and there can be no assurance that such costs would be recoverable. Unrecovered costs could have a material adverse effect on the Corporation's business, results of operations and prospects.

While the Corporation maintains insurance, the insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the possible types of liabilities that may be incurred by the Corporation will be covered by insurance. See "Underinsured and Uninsured Losses" below.

**Weather and Natural Disasters**

A major natural disaster, such as an earthquake, could severely damage the Corporation's electricity generation, transmission and distribution systems. In addition, the facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events. Although the Corporation's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Corporation operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events. The Corporation has limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC will approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute electricity to them in accordance with the Corporation's contractual obligations. Thus, any major damage to the Corporation's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Corporation.

**Permits**

The acquisition, ownership and operation of electricity businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies and First Nations. The Corporation may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the sale of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

The Corporation's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the amended and restated Canal Plant Agreement made as of July 1, 2005 (the "Canal Plant Agreement") depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows in the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States. Government authorities in Canada and the United States have the power under the treaty to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power.

**Underinsured and Uninsured Losses**

The Corporation maintains insurance coverage at all times with respect to potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's business, results of operations, financial position and prospects.

In the event of an uninsured loss or liability, the Corporation would apply to the BCUC to recover the loss (or liability) through an increased tariff. However, there can be no assurance that the BCUC would approve any such application, in whole or in part. Any major damage to the Corporation's facilities could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's business, results of operations, financial position and prospects.

**First Nations**

The Corporation provides service to customers on First Nations reserves in British Columbia and maintains generation, transmission and distribution facilities on lands that are subject to land claims by various First Nations bands. A treaty negotiation process involving various First Nations bands and the Government of British Columbia is underway in British Columbia but the basis upon which settlements might be reached in the Corporation's service area is not clear. Furthermore, not all First Nations bands are participating in the process. To date, the policy of the British Columbia government has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Corporation. However, there can be no certainty that the settlement process will not adversely affect the Corporation's business.

The Supreme Court of Canada decided in 2010 that before issuing approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult First Nations and to accommodate, if necessary, and if so whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain of the Corporation's capital projects.

**Labour Relations**

Approximately 73 per cent of the employees of the Corporation are members of labour unions that have entered into collective bargaining agreements with the Corporation. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Corporation.

There can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed.

The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have an adverse effect on the results of operations, cash flow and net income of the Corporation.

**Employee Future Benefits**

The Corporation maintains defined benefit pension plans and supplemental pension arrangements. There is no certainty that the plan assets will be able to earn the assumed rate of returns. Market driven changes impacting the performance of the plan assets may result in material variations in actual return on plan assets from the assumed return on the assets causing material changes in net benefit costs. Net benefit cost is impacted by, among other things, the discount rate, the amortization of experience and actuarial gains or losses and expected return on plan assets. Market driven changes impacting other assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in net benefit cost.

There is also measurement uncertainty associated with net benefit cost, future funding requirements, the net accrued benefit asset and accrued benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

Net benefit cost variances from forecast for rate-setting purposes were recovered through future rates using regulatory deferral accounts approved by the BCUC to the end of 2011. There can be no assurance that such net benefit cost recovery mechanisms will exist in the future as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could materially affect the Corporation's results of operations, financial position and cash flows.

**Human Resources Risk**

The ability of the Corporation to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain skilled workforces. Like other utilities across Canada, the Corporation is faced with demographic challenges relating to such skilled workforces.

**Information Technology Infrastructure**

The ability of the Corporation to operate effectively is dependent upon managing and maintaining information systems and infrastructure that support the operation of distribution, transmission and generation facilities; provide customers with billing and consumption information; and support the financial and general operating aspects of the business. System failures could have a material adverse effect on the Corporation such as sanctions and the inability to wield power. The reliability of the communication infrastructure is necessary to provide important safety information to mobile devices for field staff.

**Interest Rates**

The Corporation is exposed to interest rate risks associated with floating rate debt, however, interest variances from forecast for rate-setting purposes were recovered through future rates using regulatory deferral accounts approved by the BCUC to the end of 2011. There can be no assurance that such interest recovery mechanisms will exist in the future as they are dependent on future regulatory decisions and orders.

While the current determination of the allowed ROE is set for the Corporation, future proceedings to determine its ROE may consider the general level of interest rates as a factor for setting the ROE. As interest rates decrease, so may the allowed ROE. A significant decline in interest rates could adversely affect the Corporation's ability to earn a reasonable ROE, which, in turn, could have a material adverse effect on the financial condition and results of operations of the Corporation.

**Impact of Changes in Economic Conditions**

A general and extended decline in British Columbia's economy or in the Corporation's service area in particular, would be expected to have the effect of reducing demand for electricity over time. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. In addition, electricity demand by some of the Corporation's industrial customers could exhibit variations in demand or load in such circumstances.

Effectively, fifty per cent of electricity revenue variances from forecast for rate-setting purposes were recovered through future rates using regulatory deferral accounts approved by the BCUC through the ROE sharing mechanism in place to the end of 2011. As part of the 2012-2013 RRA, the Corporation has requested that all electricity revenue variances flow back to customers in future rates. There can be no assurance that the recovery mechanisms requested will exist for 2012 and the longer term as they are dependent on future regulatory decisions and orders.

A severe and prolonged downturn in economic conditions could materially affect the Corporation despite regulatory measures available for compensating for reduced demand.

**Capital Resources and Liquidity**

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from operations, after payment of expected expenses (including interest payments on any outstanding debt), will not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. The Corporation's ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in British Columbia, regulatory decisions regarding capital structure and ROE, the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets and the ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

Generally, the Corporation is subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Corporation's credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's finance charges. The Corporation's corporate investment-grade credit ratings were confirmed and maintained during the year and the Corporation does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, past and current global financial crisis have placed scrutiny on rating agencies and rating agency criteria that may result in changes to credit rating practices and policies.

Volatility in the global financial and capital markets may increase the cost of and affect the timing of issuance of long-term capital by the Corporation.

**Competitiveness and Commodity Price Risk**

While the Corporation currently meets the majority of its current customer supply requirements from its own generation and long-term power purchase contracts, a portion of the customer load is supplied from the market in the form of short-term and spot market power purchases. As such the Corporation is exposed to commodity price risk associated with the cost of purchased power which is affected by changes in world oil prices, natural gas prices and water levels on a regional basis. If the Corporation's price of electricity becomes too high or uncompetitive with other electricity providers or the price of other forms of energy, the Corporation's ability to recover its cost of service may be negatively affected. Effectively, fifty per cent of power supply cost variances from forecast for rate-setting purposes were recovered through future rates using regulatory deferral accounts approved by the BCUC through the ROE sharing mechanism in place to the end of 2011. As part of the 2012-2013 RRA, the Corporation has requested that all power supply cost variances flow back to customers in future rates. There can be no assurance that the recovery mechanisms requested will exist for 2012 and the longer term as they are dependent on future regulatory decisions and orders.

**Power Supply Contracts**

The Corporation's indirect customers are directly served by the Corporation's wholesale customers, who themselves are municipal utilities. Those utilities may be able to obtain alternate sources of energy supply which would result in decreased demand, higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the Corporation's cost of service in rates charged to customers.

Additionally, the Corporation has periodically entered into power supply contracts, including a long-term arrangement with BCH which expires in 2013. The Corporation may not be able to secure extensions of such agreements at their expiration dates or, if the agreements are not extended, an alternate supply of similarly-priced electricity. The Corporation is also exposed to power supply availability risk in the event of non-performance by counterparties to the various power supply contracts.

**Weather Related Demand Loss**

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. Cool summers may reduce air-conditioning demand, while warm winters may reduce electric heating load. Such fluctuations in demand could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

**Climate Change**

The Corporation's entitlement to capacity and energy under the Canal Plant Agreement may be reduced if climate change in the future leads to a significant and sustained loss of precipitation over the entire headwaters of the Kootenay River system. To have an effect on the entitlements of capacity and energy, such change would likely have to persist for a prolonged period.

**Contingency**

The Province of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a Writ and Statement of Claim against FortisBC dated August 2, 2005. The Province of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private land owners have filed separate Writs and Statements of Claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time, and accordingly no amount has been accrued in the financial statements.

## ADDITIONAL INFORMATION

Additional information about FortisBC Inc., including its Annual Information Form, is available on SEDAR at www.sedar.com.

### For further information, please contact:

Michele Leeners,
Vice President, Finance and Chief Financial Officer
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, British Columbia
V1Y 7V7
Tel: (250) 469-8013
Email: michele.leeners@fortisbc.com

David Bennett,
Vice President, General Counsel and Corporate Secretary
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, British Columbia
V1Y 7V7
Tel: (250) 717-0853
Email: david.bennett@fortisbc.com

### Website:

www.fortisbc.com

**2. Credit Rating Agency reports for the utility and corporate parent since 2006:**

- Enclosed are Rating Agency reports for FBC
- Rating Agency reports for FBC's ultimate parent, Fortis Inc. (FTS).can be found in section 2 of FEI's Company Related Document filings

a. Debt Rating

- Rating Agency reports include annual debt ratings – See reports for FBC
- Rating Agency reports include annual debt ratings - See reports for FTS in section 2 of FEI's Company Related Document filings

b. Schedule showing the history of any debt rating changes since 2002

- See schedule – "Changes in ratings since 2002"
- For FTS, see schedule – "Changes in ratings since 2002" in section 2 of FEI's Company Related Document filings

c. Interest coverage ratio and other agency's key debt ratios since 2006

- Rating Agency reports include key ratios – See reports
- Rating Agency reports include key ratios – See reports for FTS in section 2 of FEI's Company Related Document filings

***Rating Report***

| | |
|---|---|
| Report Date: | March 7, 2007 |
| Press Release: | February 26, 2007 |
| Previous Report: | November 18, 2005 |

# FortisBC Inc.

Robert Filippazzo/Jade Freadrich
+1 416 597 7340/+1 416 597 7351
rfilippazzo@dbrs.com

DBRS

*Insight beyond the rating.*

## Rating Table

| Debt Rated | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | BBB (high) | Confirmed | Stable |
| Unsecured Debentures | BBB (high) | Confirmed | Stable |

## Rating History

| | Current | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| Secured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | NR |

## Rating Update

DBRS has confirmed the ratings of FortisBC Inc. (FortisBC or the Company) as listed above, with Stable trends. The ratings continue to be supported by the Company's low business risk, which is the result of the supportive regulatory environment; its integrated operations which include a secure, low-cost power supply portfolio; and its stable financial metrics.

The Company, while experiencing significant growth over the past several years, has been able to maintain relatively stable credit metrics. For the 12 months ended December 2006, operating results showed improvement, reflecting recent regulatory approvals. In March 2006, the British Columbia Utilities Commission (BCUC) issued an order approving adjustments to the ROE calculation, including an increase in the low-risk utility premium and the inclusion of an adjustment when the Government of Canada bond yield is below 5.25%. These changes triggered an increase to FortisBC's 2006 allowable ROE from 8.69% (reflected in the original 2006 Revenue Requirement Application) to 9.2%.

Furthermore, in the negotiated May 2006 rate settlement, approved composite depreciation rates were increased from 2.6% to 3.2%, while customer rates increased by 5.9%, both of which have a positive impact on operating cash flows and coverage ratios going forward.

The Company's capital expenditure program, which has been ongoing for several years and is expected to exceed $500 million over the next five years (primarily to meet the growth in its service territory), is projected to cause continuing free cash flow deficits over the medium term.

The Company will be required to seek external debt financing, as well as equity injections from the parent, Fortis Inc. (Fortis, rated BBB (high), see separate rating report) in order to maintain its current credit profile and capital structure as approved by the BCUC. Fortis is a large, integrated electric utility holding company that has the financial ability to make these equity contributions, but the assigned ratings are based principally on the standalone credit profile of FortisBC. (Continued on page 2.)

## Rating Considerations

**Strengths**

- Supportive regulatory environment
- Low-cost, competitive hydroelectric generation base
- Secure, reasonably priced electricity supply contracts
- Diversified power supply mix and customer base

**Challenges**

- Large capital expenditure program
- Free cash flow deficits over medium term
- Comparatively small size

## Financial Highlights

| | For the 12-month period ended | | | | | | |
|---|---|---|---|---|---|---|---|
| ($ millions) | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 | Dec. 2000 |
| EBIT | 57.2 | 51.4 | 51.5 | 43.4 | 30.2 | 38.6 | 34.3 |
| Fixed-charges coverage (times) | 2.11 | 2.20 | 2.38 | 2.00 | 1.80 | 2.41 | 2.18 |
| % total debt in the capital structure | 60.9% | 61.9% | 61.2% | 61.4% | 59.3% | 57.4% | 62.4% |
| % secured debt in the capital structure | 6.6% | 7.6% | 9.2% | 31.7% | 37.3% | 28.8% | 31.8% |
| Cash flow/total debt | 11.2% | 10.1% | 11.3% | 10.9% | 8.8% | 11.7% | 10.4% |
| Cash flow/capital expenditures (times) | 0.53 | 0.40 | 0.45 | 0.59 | 0.28 | 0.60 | 0.61 |
| Free cash flow | (67.4) | (80.2) | (62.4) | (35.9) | (53.4) | (18.1) | (35.4) |
| Approved ROE | 9.20% | 9.43% | 9.55% | 9.82% | 9.53% | 9.75% | 10.00% |

## The Company

FortisBC is a vertically integrated utility holding company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 235 MW) on the Kootenay River in south-central B.C. and the Company provides electricity services to over 150,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a Canadian public holding company focused primarily on electric utility operations in Canada, the Caribbean and the United States.

RATING UPDATE (Continued from page 1.)

Over the medium term, DBRS anticipates that key credit ratios will improve modestly as a result of the expanded rate base and as capital expenditures level off, and will remain within ranges consistent with the assigned ratings.

DBRS notes that on February 26, 2007, Fortis announced its intention to acquire 100% of the common shares of Terasen Inc. (Terasen) from Kinder Morgan, Inc. for total consideration of approximately $3.7 billion, including $2.3 billion in assumed debt. The acquisition only includes Terasen's natural gas distribution businesses. DBRS believes that the transaction will not have a direct impact on FortisBC nor have a significant impact on Fortis's current ability to provide equity or similar financial support to the Company, if required. DBRS confirmed both Fortis and FortisBC's ratings shortly after the acquisition announcement.

RATING CONSIDERATIONS

**Strengths**

(1) FortisBC operates in a stable, supportive regulatory environment that allows the Company to recover its cost of service and earn a reasonable return on its investments. The Company has operated under a performance based rate (PBR) mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River System, with a total generating capacity of 235 MW. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. Therefore, a portion of the Company's earnings is relatively stable, due largely to its power supply agreement which does not fluctuate with water levels, as is the case with other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licenses and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts including: (a) a long-term "take or pay" contract with Brilliant Power Corporation (Brilliant), rated A (high) with a Stable trend (for further details please refer to separate DBRS reports). The contract runs until 2056 and supplies low-cost power representing close to 26% of the Company's energy needs; and (b) a power purchase contract with the government-owned BC Hydro, rated AA, with a Stable trend (refer to separate DBRS report). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating the renewal of the contract. As it currently stands, approximately 98% of FortisBC's energy requirements are met through the combination of owned generation and these supply sources, at least until 2013. However, only 76% of its peak capacity requirements are met through these same resources. The balance of supply is met through market purchases.

(4) The Company has a diverse customer base, which provides a degree of stability to revenues and earnings. For 2006, electricity sales to stable residential customers accounted for about 43% of total sales, while 25% of sales were to commercial customers and 23% to wholesale customers (who in turn, sell primarily to residential and commercial customers). Only 9% of sales were to low-margin, economically sensitive industrial customers. The diversification and low reliance on economically sensitive customers helps to mitigate the potential negative impacts of an economic downturn.

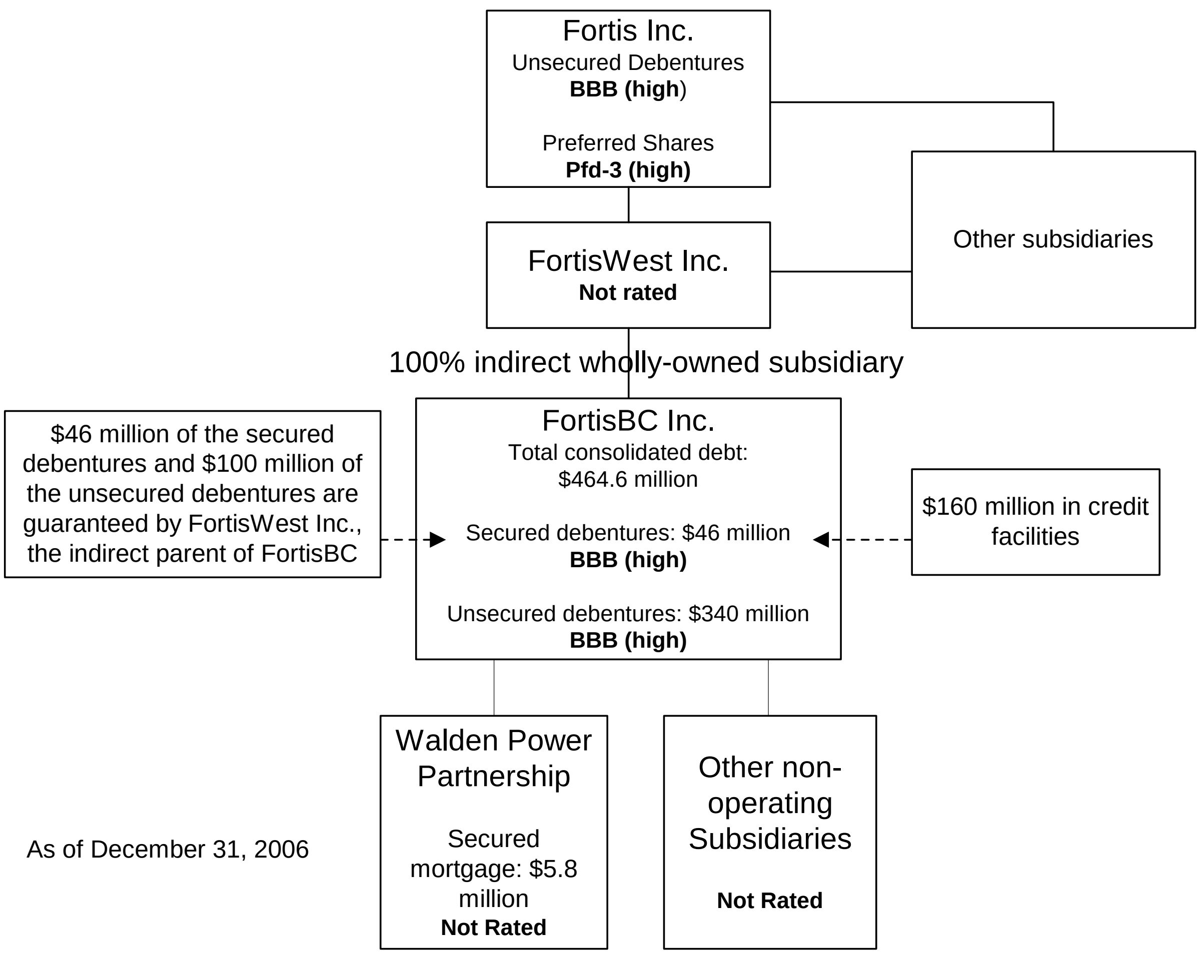
**Challenges**

(1) FortisBC's financial profile is not as strong as other comparable regulated utilities in Canada, given various factors including consistent free cash flow deficits due to a large capital expenditure program; however, it continues to remain acceptable for the current ratings. The Company's current capital expenditure program has been ongoing for several years and is expected to exceed $500 million in projects over the next five years. FortisBC is allowed to earn a return on the average capital expenditure over the year in which it is incurred, occasionally causing a slight regulatory lag in the recovery of costs and potentially contributing to ongoing free cash flow deficits. The Company will need to seek external debt financing during this period of capital growth, which will likely keep key coverage ratios relatively flat during this period. However, Fortis is expected to provide equity contributions in order to maintain the Company's deemed capital structure. Furthermore, the depreciation study completed in 2005 resulted in BCUC-approved composite depreciation rates increasing from 2.6% to 3.2% effective January 1, 2006, which positively impacts current and future operating cash flows and limits projected free cash flow deficits.

(2) The Company faces execution risk with regards to its large capital expenditure program over the next five years. The focus will be on improving the strength and reliability of the transmission system, which is needed as a result of the strong growth in FortisBC's service territory, and also increasing the importance of completing projects on time and on budget. However, it should be noted that the Company is already a number of years into the current capital expenditure program, with a number of projects already complete.

(3) FortisBC is a small utility compared to the dominant utility in the province, the Crown-owned BC Hydro, and serves a rural and low-population density region in south-central British Columbia. To some extent, the small size and franchise area limit opportunities for growth, operating efficiencies, and economies of scale as they relate to PBR.

## ABBREVIATED OWNERSHIP/DEBT CHART



## REGULATION

- FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure, the allowed rate of return on deemed common equity (ROE), as well as approve and oversee the construction of new projects. Rates are based on a cost-of-service methodology with some Performance Based Rate (PBR) setting attributes.
- FortisBC files annual rate applications for the 12-month period beginning on January 1. Through a negotiated settlement process with a group of interveners, the Company's 2006 revenue requirements were finalized and approved by the BCUC in May 2006. Key elements of the settlement include:
  - A rate increase of 5.9%, effective January 1, 2006.
  - ROE of 9.20%, with an equity thickness of 40%.
  - 2006 will become the base year for a PBR term from 2006 to 2008, with an option to continue the term into 2009.
  - The composite depreciation rate increased from 2.6% in 2005 to 3.2% effective January 1, 2006.
- In December 2006, FortisBC received approval from the BCUC for a 1.2% general rate increase, effective January 1, 2007. The increase is driven primarily by capital programs and increased purchased power costs.
- For the current 2006 to 2008 PBR term:
  - Gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (CPI for B.C.) minus a productivity improvement factor of 2% in 2007, 2% in 2008 and 3% in 2009.
  - Capitalized overhead will be set at 20% of forecast gross operating and maintenance expense.
  - Positive and negative variances in interest expense are a flow through to customers.
  - A 2% collar has been set around the allowed ROE whereby all variances (adjusted for certain variances which flow through to the customer) as a result of actual financial performance, positive or negative, will be shared equally between the customer and shareholder. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review during the next rate setting process.
  - Other components of revenue requirements will be forecast annually.
- The allowed ROE is linked to the forecast long-term Government of Canada (GoC) bond yield and was set at 9.43% for 2005, compared with 9.55% in 2004 and 9.82% in 2003. In March 2006, the BCUC issued an order approving adjustments to the ROE mechanism, including an increase in the low-risk utility premium and the inclusion of an adjustment when the GoC bond yield is below 5.25%. These changes resulted in the 2006 ROE for FortisBC increasing from 8.69% (reflected in the original 2006 Revenue Requirement Application) to 9.20%.
- FortisBC filed its 2006 Capital Plan in August 2005 in the amount of $111.7 million. The BCUC approved the plan on January 31, 2006. As part of the 2006 Revenue Requirements and Negotiated Settlement, approved by the BCUC in May 2006, the 2006 Capital Plan was revised down to $99.5 million.
- The 2007-2008 Capital Expenditure Plan (2007 – $128.6 million, 2008 – $111.6 million) was approved on November 24, 2006, with six projects totalling $61.2 million subject to further approval process.
- FortisBC capitalizes its costs of financing major capital projects during the period of construction. The Company earns a return on the total project costs, including financing costs capitalized, after the projects are put in service.

## EARNINGS OUTLOOK

| | For the 12-month period ended | | | | | | |
|---|---|---|---|---|---|---|---|
| ($ millions) | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 | Dec. 2000 |
| Revenues | 207.6 | 190.6 | 183.4 | 167.9 | 154.0 | 147.9 | 138.9 |
| EBITDA | 84.1 | 70.3 | 68.6 | 58.2 | 44.9 | 48.5 | 44.2 |
| EBIT | 57.2 | 51.4 | 51.5 | 43.4 | 30.2 | 38.6 | 34.3 |
| Gross interest expense | 26.7 | 23.0 | 21.3 | 21.0 | 16.8 | 16.0 | 15.7 |
| Core net income | 26.5 | 24.5 | 23.6 | 19.2 | 11.7 | 16.7 | 12.5 |
| Net income (reported) | 26.5 | 23.5 | 21.9 | 19.2 | 6.1 | 16.7 | 12.5 |
| Return on average common equity | 9.6% | 10.3% | 11.8% | 11.0% | 7.2% | 11.7% | 10.0% |

**Summary**

- EBIT has exhibited stable growth since 2002 as a result of an expanding rate base and a growing customer base in the Company’s service territory. FortisBC’s operations are almost 100% regulated, providing strong stability to earnings.
- Higher EBIT for the 12 months ended December 31, 2006, was the result of:
  - Higher overall electricity sales resulting from continued population growth in the Okanagan region.
  - Electricity revenue being $19.9 million higher than 2005. The increase is a result of a 5.9% increase in rates, which became effective January 1, 2006, and customer growth.
- Interest expense also increased as a result of increased borrowings in order to finance the capital expenditure program.
- The low interest rate environment previously negatively impacted the allowable ROE and coverage ratios. However, changes in the calculation of allowable ROE were approved in March 2006, which partially offsets the lower-than-normal interest rates, as well as increasing the low-risk utility premium. As a result, allowable ROE for 2006 increased from 8.69% (reflected in the original 2006 Revenue Requirement Application) to 9.20%.

**Outlook**

- DBRS expects EBIT and net income to grow over the medium term, driven primarily by the economic expansion in the Company’s service area and its growing rate base related to large capital projects, including electricity transmission upgrades, substation and terminal development and turbine upgrades.
  - Key credit metrics are expected to modestly improve over the same period as a result of the expanded rate base and as capital expenditures level off.

## FINANCIAL PROFILE

| ($ millions) | For the 12-month period ended | | | | | | |
|---|---|---|---|---|---|---|---|
| **Cash Flow Statement** | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 | Dec. 2000 |
| Core net income | 26.5 | 24.5 | 23.6 | 19.2 | 11.7 | 16.7 | 12.5 |
| Depreciation and amortization | 26.9 | 18.8 | 17.1 | 14.8 | 14.7 | 9.8 | 9.9 |
| Other non-cash adjustments | (0.1) | (0.1) | 0.1 | (0.3) | (4.5) | (1.5) | (0.3) |
| **Cash Flow From Operations** | 53.3 | 43.3 | 40.8 | 33.7 | 21.9 | 25.1 | 22.1 |
| Common dividends | (10.2) | (8.0) | (9.7) | (10.6) | (9.6) | (6.8) | (6.8) |
| Capital expenditures | (101.1) | (108.0) | (90.9) | (57.1) | (78.8) | (41.5) | (36.5) |
| **Free Cash Flow Before W/C Changes** | (58.0) | (72.6) | (59.8) | (34.1) | (66.5) | (23.2) | (21.2) |
| Net changes in working capital | (9.4) | (7.5) | (2.6) | (1.8) | 13.1 | 5.1 | (14.2) |
| **Net Free Cash Flow** | (67.4) | (80.2) | (62.4) | (35.9) | (53.4) | (18.1) | (35.4) |
| Other investing activities | (2.8) | (1.0) | (2.2) | (2.2) | (0.1) | (2.3) | (0.7) |
| Other adjustments | 2.8 | (3.2) | (4.1) | 0.9 | 5.5 | (0.8) | 0.0 |
| **Amount to be Financed** | (67.4) | (84.4) | (68.8) | (37.2) | (48.0) | (21.2) | (36.1) |
| Net debt financing | 40.9 | 69.9 | 38.2 | 37.0 | 33.4 | 0.7 | 36.0 |
| Net equity financing | 20.0 | 21.5 | 30.0 | 0.0 | 15.0 | 20.0 | 0.0 |
| Other financing | 0.0 | (1.5) | 1.5 | 0.1 | (0.3) | 0.0 | 0.0 |
| **Net Change in Cash** | (6.4) | 5.5 | 0.9 | (0.0) | 0.0 | (0.5) | (0.1) |
| | | | | | | | |
| % debt in capital structure | 60.9% | 61.9% | 61.2% | 61.4% | 59.3% | 57.4% | 62.4% |
| Fixed-charges coverage (times) | 2.11 | 2.20 | 2.38 | 2.00 | 1.80 | 2.41 | 2.18 |
| Cash flow/total debt | 11.2% | 10.1% | 11.3% | 10.9% | 8.8% | 11.7% | 10.4% |
| Total debt to EBITDA (times) | 5.67 | 6.12 | 5.27 | 5.32 | 5.54 | 4.41 | 4.82 |

**Summary**

- For the 12 months ended December 31, 2006, FortisBC's cash flow from operations increased, as a result of improved earnings, depreciation and amortization, as well as deferred charges. The increase in depreciation expense was due to a larger depreciable asset base and a change in the estimated composite depreciation rate from 2.6% to 3.2%, effective January 1, 2006.
- However, due to the Company's ongoing capital expenditure program, free cash flow deficits continued for the period.
- FortisBC financed these cash flow deficits with a combination of incremental debt financing coupled with equity injections from Fortis.
- Despite the incremental increase in debt financing, the Company's cash flow-to-total debt ratio has remained relatively constant, and improved for the 12 months ended December 31, 2006, as a result of higher operating cash flow.

**Outlook**

- Cash flow from operations is expected to continue to grow in line with both the rate base and economic growth in the Company's franchise area.
- However, FortisBC will continue to record free cash flow deficits over the medium term.
  - Annual capital expenditures are expected to remain high, with $500 million in projects planned over the next five years. The focus will be on the improvement of the transmission and distribution systems in order to meet the strong growth in the Company's service territory.
  - Planned capital expenditures are expected to normalize by 2012.
- DBRS expects that Fortis will continue to inject equity as required in order to maintain the capital structure at BCUC-approved levels (60/40 debt and equity).
- Despite the free cash flow deficits, the Company's financial profile should continue to remain acceptable for the ratings.
  - Key credit ratios are expected to be flat over the medium term as increased debt levels should be offset by greater income earned on a growing rate base.

LONG-TERM DEBT MATURITIES AND BANK LINES

| ($ millions) | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 26.7 | 21.7 | 53.8 | 0.8 | 0.9 | 331.9 | 435.8 |
| Sinking fund payments | 0.75 | 0.75 | 0.75 | 0.0 | 0.0 | 0.0 | 2.3 |
| as at Dec. 31, 2006 | 27.4 | 22.4 | 54.5 | 0.8 | 0.9 | 331.9 | 438.1 |

**Summary**

- As of December 31, 2006, the Company had $464.6 million of total debt outstanding including $340 million of unsecured debentures, $51 million of secured debt, $47 million in credit facilities and $26.5 million in capital lease obligations. The secured debt is expected to continue to become a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures and three series of unsecured debentures (Series H, I, and J), totalling $146 million (33% of total debt) is also guaranteed by FortisWest Inc. (FW). FW is a direct wholly owned subsidiary of Fortis whose sole assets are comprised of shares in FortisBC and FortisAlberta.
- The debt comprises the following:
  - $46 million in secured debentures, Series E, F and G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company, of which one series requires sinking fund payments of $750,000 per year. These debentures mature between 2009 and 2023.
  - $100 million in unsecured debentures, Series H, I and J, which are also guaranteed by FW and mature between 2009 and 2021.
  - An additional $240 million of unsecured debentures, issued in two series that mature in 2014 and 2035.
  - A $5.8 million mortgage on the Walden power plant, owned and operated by the Walden Power Partnership (WPP), which is secured by a pledge by FortisBC of its interest in WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.
- FortisBC currently has the following credit facilities:
  - A $100 million, three-year revolving unsecured credit facility, maturing May 12, 2008.
  - An additional $50 million 364-day revolving unsecured credit facility, maturing May 11, 2007, which may be extended for another 364-days or, if not extended, termed-out for a six-month period.
  - A $10 million demand overdraft facility.
- The Company's recently acquired, wholly owned subsidiary, Princeton Light & Power, had a $5.4 million credit facility available to it as of December 31, 2006. In January 2007, the $4.5 million outstanding was repaid and the facilities were cancelled.
- FortisBC borrowed and repaid a $10 million, 4.53% demand note from Fortis during the year ended December 31, 2006. Interest expense of $104,000 was expensed during the year.

**Outlook**

- The Company's $160 million in bank credit facilities should provide sufficient liquidity to meet any short-term funding requirements.
  - As at December 31, 2006, $112.8 million was available.
- The Company anticipates issuing additional debt in late 2007 or early 2008 in order to fund its capital expenditures program and refinance bank debt.

## Description of Operations

- FortisBC is a vertically integrated utility operating in south-central British Columbia.
- Its mid-year rate base as of December 31, 2005, was $590 million and is expected to be $681 million in December 2006.
- FortisBC currently has approximately 102,000 direct and 50,000 indirect customers, including wholesale customers such as the cities of Kelowna and Nelson. Customer growth has been steady, averaging 2.3% over the past five years.
- Approximately 68% of power sold is to relatively stable residential and commercial customers, where only 9% is sold to economically sensitive industrial customers, while 23% is sold to wholesale customers who resell the power to their own residential and commercial customers.
- FortisBC meets its customers' power requirements through the following sources:
  - Four owned hydroelectric plants, with 235 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, originally signed in August 1972, and renewed in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows.
  - Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2011. As a result, total capacity has increased from 205 MW in 2004 to current levels.
  - A purchase power contract with the Brilliant hydroelectric plant, which expires in 2056, supplies approximately 26% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant Power Corporation.
  - Between 2000 and 2002, the Brilliant plant's turbines were upgraded, increasing their output by 125,000 MWh of energy per year. FortisBC acquires an additional 65,000 MWh of energy from the plant under an amended PPA.
  - A long-term, firm power purchase contract with BC Hydro expiring in 2013, which provides approximately 27% of the Company's energy needs.
  - A number of small purchase power contracts with independent power producers collectively provide approximately 2% of the Company's energy requirements.
  - Any electricity requirements not met by the above sources are satisfied through the spot market.
- FortisBC also has a limited amount of non-regulated operations, principally made up of the Walden Power Partnership, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a power purchase agreement which expires in 2013.

| Generation | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 |
|---|---|---|---|---|---|---|
| | For the 12-month period ended | | | | | |
| Hydro capacity (MW) | 235 | 214 | 205 | 205 | 205 | 205 |
| Gross energy generated (GWh) | 1,509 | 1,625 | 1,491 | 1,548 | 1,512 | 1,510 |
| Plus: purchases | 1,896 | 1,724 | 1,802 | 1,661 | 1,614 | 1,516 |
| Energy generated + purchased | 3,405 | 3,349 | 3,293 | 3,209 | 3,126 | 3,026 |
| Less: transmission losses + internal use | 365 | 378 | 388 | 347 | 336 | 295 |
| Total GWh sold | 3,040 | 2,971 | 2,905 | 2,862 | 2,790 | 2,731 |
| Energy lost + used/energy gen. + purch. | 10.7% | 11.3% | 11.8% | 10.8% | 10.7% | 9.7% |

| Electricity Sold - Breakdown | % | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 |
|---|---|---|---|---|---|---|---|
| | | For the 12-month period ended | | | | | |
| Residential | 36% | 1,091 | 1,068 | 1,071 | 1,013 | 1,008 | 986 |
| General Service | 21% | 657 | 632 | 551 | 520 | 524 | 522 |
| Industrial | 11% | 344 | 357 | 340 | 337 | 337 | 336 |
| Wholesale* | 32% | 978 | 952 | 942 | 992 | 922 | 887 |
| Total - GWh sold | | 3,070 | 3,009 | 2,905 | 2,862 | 2,791 | 2,731 |
| *Year over year growth* | | 2.0% | 3.6% | 1.5% | 2.5% | 2.2% | 0.5% |

**FortisBC Inc.**

| Balance Sheet ($ millions) | Dec. 2006 | Dec. 2005 | Dec. 2004 | Liabilities & Equity | Dec. 2006 | Dec. 2005 | Dec. 2004 |
|---|---|---|---|---|---|---|---|
| | As at | | | | As at | | |
| **Assets** | | | | Short-term debt | 26.0 | 0.0 | 28.6 |
| Cash + equivalents | 0.0 | 6.5 | 0.3 | Debt due one yr. | 1.4 | 1.3 | 1.3 |
| Accounts receivable/unbilled revenue | 45.8 | 33.5 | 34.9 | A/P + accr'ds | 41.1 | 37.8 | 46.0 |
| Inventories | 0.7 | 0.4 | 0.5 | **Current Liabilities** | 68.5 | 39.2 | 75.9 |
| Other | 2.6 | 4.4 | 2.3 | Long-term debt | 359.6 | 338.7 | 238.7 |
| **Current Assets** | 49.1 | 44.8 | 38.1 | Secured debt | 51.1 | 52.4 | 53.7 |
| | | | | Capital lease obligations | 26.5 | 25.8 | 26.0 |
| Net fixed assets | 731.2 | 647.7 | 557.7 | Other l.t. liabilities | 11.7 | 9.2 | 8.1 |
| Deferred charges | 34.6 | 30.2 | 27.1 | Shareholders' equity | 297.7 | 257.5 | 220.5 |
| **Total** | 815.0 | 722.7 | 622.9 | **Total** | 815.0 | 722.7 | 622.9 |

| Ratio Analysis | For the 12-month period ended | | | | | | |
|---|---|---|---|---|---|---|---|
| **Liquidity Ratios** | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 | Dec. 2001 | Dec. 2000 |
| Current ratio | 0.72 | 1.15 | 0.50 | 0.29 | 0.50 | 0.48 | 0.49 |
| Accumulated depreciation/gross fixed assets | 22.7% | 22.6% | 24.0% | 26.3% | 27.9% | 28.0% | 29.2% |
| Cash flow/adjusted debt (1) | 11.2% | 10.1% | 11.3% | 10.9% | 8.8% | 11.7% | 10.4% |
| Cash flow/capital expenditures | 0.53 | 0.40 | 0.45 | 0.59 | 0.28 | 0.60 | 0.61 |
| Cash flow-dividends/capital expenditures | 0.43 | 0.33 | 0.34 | 0.40 | 0.16 | 0.44 | 0.42 |
| % debt in capital structure | 60.9% | 61.9% | 61.2% | 61.4% | 59.3% | 57.4% | 62.4% |
| % adjusted debt in capital structure (1) | 61.6% | 62.5% | 62.1% | 63.5% | 59.4% | 57.4% | 62.4% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| **Coverage Ratios** (1) | | | | | | | |
| EBIT interest coverage | 2.11 | 2.20 | 2.38 | 2.00 | 1.80 | 2.41 | 2.18 |
| EBITDA interest coverage | 3.09 | 2.99 | 3.15 | 2.66 | 2.66 | 3.02 | 2.81 |
| Fixed-charges coverage | 2.11 | 2.20 | 2.38 | 2.00 | 1.80 | 2.41 | 2.18 |
| Adjusted debt/EBITDA | 5.67 | 6.12 | 5.27 | 5.32 | 5.54 | 4.41 | 4.82 |
| **Earnings Quality/Operating Efficiency** | | | | | | | |
| Power purchases/revenues | 32.6% | 31.7% | 32.2% | 34.8% | 33.9% | 34.5% | 34.3% |
| EBIT margin | 27.6% | 27.0% | 28.1% | 25.9% | 19.6% | 26.1% | 24.7% |
| Net margin (before extras) | 12.8% | 12.9% | 12.9% | 11.4% | 7.6% | 11.3% | 9.0% |
| Return on avg. common equity (before extras) | 9.6% | 10.3% | 11.8% | 11.0% | 7.2% | 11.7% | 10.0% |
| Allowed ROE – mid-point | 9.20% | 9.43% | 9.55% | 9.82% | 9.53% | 9.75% | 10.00% |
| Direct customers/employee | 181 | 199 | 246 | 241 | 236 | 225 | 213 |
| Growth of customer base | 1.9% | 2.6% | 1.9% | 1.9% | 3.8% | 1.2% | -0.7% |
| GWh sold/employee | 5.4 | 5.9 | 7.4 | 7.2 | 7.1 | 6.9 | 6.6 |
| Mid-year rate base ($ millions)(2) | 681.0 | 590.0 | 499.0 | 443.0 | 401.9 | 349.5 | 318.2 |
| Growth in rate base | 15.4% | 18.2% | 12.6% | 10.2% | 15.0% | 9.9% | 13.8% |

(1) Adjusted for operating leases. (2) Forecasted rate base for December 2006.

Note:
All figures are in Canadian dollars unless otherwise noted.

**Rating Report**
**Report Date:**
April 30, 2008
**Report Date:**
March 7, 2007

Insight beyond the rating.

# FortisBC Inc.

**Analysts**
**Robert Filippazzo**
+1 416 597 7340
rfilippazzo@dbrs.com

**Roshan Thiru**
+1 416 597 7357
rthiru@dbrs.com

**The Company**
FortisBC is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 MW) on the Kootenay River in south-central B.C. and the Company provides electricity services to approximately 154,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a Canadian public holding company focused primarily on electric utility operations in Canada, the Caribbean and the United States.

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | BBB (high) | Confirmed | Stable |
| Unsecured Debentures | BBB (high) | Confirmed | Stable |

## Rating Rationale

DBRS has confirmed the ratings of FortisBC Inc.'s (FortisBC or the Company) Secured and Unsecured Debentures at BBB (high), with Stable trends. The rating confirmation reflects FortisBC's low business risk stemming from the regulated nature of its operations and supportive regulatory environment, its integrated operations, which include a secure low-cost hydro-based power supply portfolio and a diversified customer base, and its stable credit metrics.

The regulatory environment continues to remain stable and supportive, providing a strong cost-of-service/rate-of-return rate setting methodology with some performance-based rate (PBR) setting attributes. The cost-of-service methodology allows for a full recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame.

As part of the 2008 revenue-requirements approval, the British Columbia Utilities Commission (BCUC) approved an electricity rate increase of 2.9% and a return on equity (ROE) of 9.02% on its 60%/40% deemed capital structure. The rate increase was reduced by the strong F2007 financial performance, as 50% of the ROE above the original allowed level had to be returned to customers through a reduction in 2008 rates, according to the current PBR in place. The settlement agreement approved by the BCUC in May 2006, which allowed for an increase in the composite depreciation rates from 2.6% to 3.2% and a change in the allowed ROE mechanism approved by the BCUC in March 2006, continues to positively impact cash flows and EBITDA interest-coverage ratios.

On July 4, 2007, the Company closed the issuance of $105 million in senior unsecured debentures to repay existing indebtedness incurred under the bank credit facilities, and for general corporate purposes, including ongoing capital expenditures. (Continued on page 2.)

## Rating Considerations

**Strengths**
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

**Challenges**
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Comparatively small size

## Financial Information

| | For the 12-month period ended | | | | |
|---|---|---|---|---|---|
| ($ millions) | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 |
| EBIT | 62.7 | 57.2 | 51.4 | 51.5 | 43.4 |
| Fixed-charges coverage (times) | 2.04 | 2.11 | 2.20 | 2.38 | 2.00 |
| EBITDA interest coverage | 3.04 | 3.09 | 2.99 | 3.15 | 2.66 |
| % total debt in the capital structure | 61.1% | 60.9% | 61.9% | 61.2% | 61.4% |
| % secured debt in the capital structure | 5.6% | 6.6% | 7.6% | 9.2% | 31.7% |
| Cash flow/total debt | 11.4% | 11.2% | 10.1% | 11.3% | 10.9% |
| Cash flow/capital expenditures (times) | 0.45 | 0.53 | 0.40 | 0.45 | 0.59 |
| Free cash flow | (73.3) | (67.4) | (80.2) | (62.4) | (35.9) |
| Approved ROE | 8.77% | 9.20% | 9.43% | 9.55% | 9.82% |

## Rating Rationale (Continued from page 1.)

The Company's elevated capital expenditure program, which has been ongoing for several years and is expected to exceed $500 million over the next five years, is projected to cause continuing free cash flow deficits over the medium term. The primary focus of this large capital program will be the improvement of the transmission and distribution systems in order to meet the strong growth and increased reliability in the Company's service territory. The resulting free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent, Fortis Inc. (Fortis, rated BBB (high), see separate DBRS rating report) to maintain its current credit profile and capital structure at the regulatory-approved levels. Fortis is a large, integrated utility holding company that has the financial wherewithal to provide equity support as required in this context.

DBRS expects the key credit ratios to remain stable over the next few years before showing modest improvement as capital expenditures level off. Despite the continuing free cash flow deficits over the near to medium term, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating.

## Rating Considerations Details

**Strengths**

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a reasonable return on its investments. The Company has operated under a PBR mechanism, in one capacity or another since 1996, providing it with incentives for achieving productivity improvements.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River System, with a total generating capacity of 223 MW, which provide about 45% of energy and 30% of capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing water flow risk to this portfolio which is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licenses and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts including: (a) a long-term "take or pay" contract with Brilliant Power Corporation (Brilliant), rated A (high) with a Stable trend (see separate DBRS rating report dated September 19, 2007). The contract runs until 2056 and supplies low-cost power representing close to 26% of the Company's energy needs; and (b) a power purchase contract with the government-owned British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated April 18, 2007). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating renewal of the contract. As it currently stands, approximately 98% of FortisBC's energy requirements are met through the combination of owned generation and these supply sources. However, approximately 80% of its peak capacity requirements are met through these same resources. The balance of supply is met through small power purchase contracts and spot market purchases. Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (which account for approximately 2% of the Company's energy load requirements) are passed through to customers as well. The Company has made various types of advance purchases including capacity purchases, call options and fixed price energy purchases to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2007, electricity sales to stable residential customers accounted for about 38% of total sales volume, while 22% of sales were to commercial customers and 29% to wholesale customers (who, in turn, sell primarily to residential and commercial customers). Only 11% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impacts of an economic downturn.

**FortisBC Inc.**

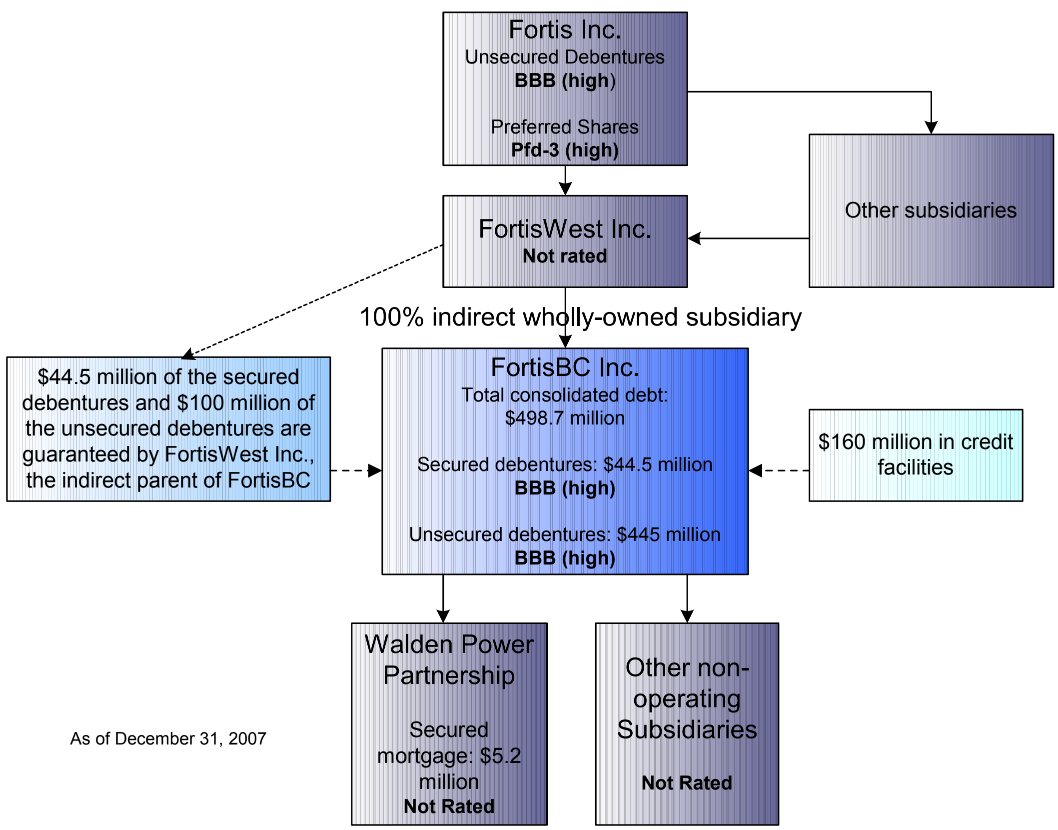
**Report Date:**
April 30, 2008

**Challenges**
(1) FortisBC's financial profile continues to be impacted by free cash flow deficits due to the ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's current capital expenditure program has been ongoing for several years and is expected to exceed $500 million in projects over the next five years. Over the next few years, internal cash flow generation (net of dividends) will continue to fund 35% to 40% of capital expenditures, with the remainder financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining capital structure at the regulatory-approved 60%/40%. The Company will need to seek external debt financing during this period of capital growth, which will likely keep key coverage ratios relatively flat during this period. Fortis is expected to provide equity support as needed in order to maintain the Company's regulatory-approved capital structure.

(2) The Company faces execution risk with regard to its large capital expenditure program over the next five years. The focus will be on improving the strength and reliability of the transmission and distribution system – in view of the strong growth in FortisBC's service territory – and also on completing projects on budget. However, it should be noted that the Company is already a number of years into the current capital expenditure program, with several projects already complete.

(3) FortisBC is a small utility compared with the dominant utility in the province, the Crown-owned BC Hydro, and serves a rural and low-population density region in south-central British Columbia. To some extent, the small size and franchise area limit opportunities for growth, operating efficiencies, and economies of scale as they relate to PBR.

## Simplified Ownership/Debt Chart



## Earnings and Outlook

### Consolidated Earnings

| ($ millions) | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 |
|---|---|---|---|---|---|---|
| | For the 12-month period ended | | | | | |
| Revenues | 218.3 | 207.6 | 190.6 | 183.4 | 167.9 | 154.0 |
| EBITDA | 93.8 | 84.1 | 70.3 | 68.6 | 58.2 | 44.9 |
| EBIT | 62.7 | 57.2 | 51.4 | 51.5 | 43.4 | 30.2 |
| Gross interest expense | 30.4 | 26.7 | 23.0 | 21.3 | 21.0 | 16.8 |
| Core net income | 30.1 | 26.5 | 24.5 | 23.6 | 19.2 | 11.7 |
| Net income (reported) | 30.1 | 26.5 | 23.5 | 21.9 | 19.2 | 6.1 |
| Return on average common equity | 9.6% | 9.6% | 10.3% | 11.8% | 11.0% | 7.2% |
| | | | | | | |
| Rate Base | 747.2 | 681.0 | 590.0 | 499.0 | 443.0 | 401.9 |
| Growth in Rate Base | 9.7% | 15.4% | 18.2% | 12.6% | 10.2% | 15.0% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Approved ROE | 8.77% | 9.20% | 9.43% | 9.55% | 9.82% | 9.53% |

**Summary**

FortisBC has historically demonstrated strong and stable growth in EBITDA and EBIT, reflective of its expanding customer base and rate base, somewhat offset by declining allowed ROEs. FortisBC's operations are almost 100% regulated, providing strong stability to earnings and cash flows. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the majority of the Company's margin.

Prior to March 2006, the prevailing low interest rate environment negatively impacted the allowable ROE and coverage ratios to a greater extent than today, as changes were made in the calculation of allowable ROE, partially offsetting the lower-than-normal interest rates, as well as increasing the low-risk utility premium.

The impact of power price volatility on earnings is limited as power procurement-related costs are passed through to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply approximately 98% of FortisBC's power load requirements are automatically passed through to customers. The remaining 2% is procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed through to customers as well. The Company has made various types of advance market purchases including capacity purchases and fixed price energy purchases to help mitigate the risks of market volatility and availability on its spot market purchases.

Interest expense has risen as a result of increased borrowings sourced to finance the large capital expenditure program; however, coverages continue to remain fairly stable due to earnings growth.

**Outlook**

DBRS expects EBIT and net income to continue to grow over the medium term, driven primarily by the economic expansion in the Company's service area, which is anticipated to witness increasing electricity demand due to the upcoming 2010 Olympics, airport expansion and provincial infrastructure investments, as well as general population and customer growth, especially in the Okanagan region. This will result in a growing rate base related to large capital projects, including electricity transmission upgrades, substation and terminal development and turbine upgrades.

Key credit metrics are expected to remain relatively stable over the next few years before showing modest improvement, along with free cash flow deficits, as capital expenditures level off.

FortisBC Inc.

**Report Date:**
April 30, 2008

# Financial Profile

| ($ millions) | For the 12-month period ended | | | | | |
|---|---|---|---|---|---|---|
| **Cash Flow Statement** | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 | Dec. 2002 |
| Core net income | 30.1 | 26.5 | 24.5 | 23.6 | 19.2 | 11.7 |
| Depreciation and amortization | 31.1 | 26.9 | 18.8 | 17.1 | 14.8 | 14.7 |
| Other non-cash adjustments | (0.1) | (0.1) | (0.1) | 0.1 | (0.3) | (4.5) |
| **Cash Flow From Operations** | 61.0 | 53.3 | 43.3 | 40.8 | 33.7 | 21.9 |
| Common dividends | (11.8) | (10.2) | (8.0) | (9.7) | (10.6) | (9.6) |
| Capital expenditures | (134.2) | (101.1) | (108.0) | (90.9) | (57.1) | (78.8) |
| **Free Cash Flow Before W/C Changes** | (85.0) | (58.0) | (72.6) | (59.8) | (34.1) | (66.5) |
| Net changes in working capital | 11.7 | (9.4) | (7.5) | (2.6) | (1.8) | 13.1 |
| **Net Free Cash Flow** | (73.3) | (67.4) | (80.2) | (62.4) | (35.9) | (53.4) |
| Other investing activities | (0.1) | (2.8) | (1.0) | (2.2) | (2.2) | (0.1) |
| Other adjustments | (0.6) | 2.8 | (3.2) | (4.1) | 0.9 | 5.5 |
| **Amount to be Financed** | (74.0) | (67.4) | (84.4) | (68.8) | (37.2) | (48.0) |
| Net debt financing | 60.2 | 40.9 | 69.9 | 38.2 | 37.0 | 33.4 |
| Net equity financing | 15.0 | 20.0 | 21.5 | 30.0 | 0.0 | 15.0 |
| Other financing | (1.2) | 0.0 | (1.5) | 1.5 | 0.1 | (0.3) |
| **Net Change in Cash** | (0.0) | (6.4) | 5.5 | 0.9 | (0.0) | 0.0 |
| | | | | | | |
| % debt in capital structure | 61.1% | 60.9% | 61.9% | 61.2% | 61.4% | 59.3% |
| EBIT interest coverage (times) | 2.04 | 2.11 | 2.20 | 2.38 | 2.00 | 1.80 |
| Cash flow/total debt | 11.4% | 11.2% | 10.1% | 11.3% | 10.9% | 8.8% |
| Total debt to EBITDA (times) | 5.69 | 5.67 | 6.12 | 5.27 | 5.32 | 5.54 |
| Dividend payout ratio | 39.3% | 38.5% | 32.6% | 41.2% | 55.3% | 82.1% |

## Summary

FortisBC's cash flow from operations has historically displayed underlying stability and growth due to both earnings and investment in plants. The increase in depreciation expense in recent years is due to a larger depreciable asset base and a change in the estimated composite depreciation rate from 2.6% to 3.2%, effective January 1, 2006.

Although FortisBC continues to maintain strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits that are financed with a combination of incremental debt and equity from Fortis, with the target of maintaining capital structure at the regulatory-approved 60%/40%. Overall, the Company has maintained a reasonable financial profile, reflecting a solid and stable balance sheet and adequate credit metrics for the rating.

## Outlook

Free cash flow deficits are expected to persist over the 2008-2011 period, attributable to the large capital expenditures program over this period. Annual capital expenditures are expected to remain high, with $500 million in projects planned over the next five years. With annual average capital expenditures expected to be at F2007 levels over the next few years, the Company will have average financing requirements, after dividends, in the $80 million to $100 million range annually, which we expect will be financed with incremental debt and equity from Fortis. The focus will be on the improvement of the transmission and distribution systems in order to meet the strong growth in the Company's service territory. Once the capital expenditures level off around 2012, we expect the cash flow from operations to be largely adequate to fund future capital expenditures.

Free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent to maintain leverage at the regulatory-approved levels. Thus, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat during this elevated capital program period as increased debt levels will be offset by higher earnings on a growing rate base.

**FortisBC Inc.**

**Report Date:**
April 30, 2008

## Long-Term Debt Maturities and Liquidity

| Maturity Schedule ($mn) | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 0.7 | 53.8 | 0.8 | 0.9 | 16.0 | 420.9 | 493.2 |
| Sinking fund payments | 0.8 | 0.8 | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 |
| as at Dec. 31, 2007 | 1.4 | 54.5 | 0.8 | 0.9 | 16.0 | 420.9 | 494.7 |

Debt Chart ($millions)

| | | Dec. '07 |
|---|---|---|
| Secured Debentures | | |
| *Guaranteed by FortisWest Inc.* | | |
| * Dec. '09 | 11.0% | 4.5 |
| Oct. '12 | 9.65% | 15.0 |
| Aug. '23 | 8.80% | 25.0 |
| WPP Mortgage | | |
| Oct. '13 | 9.44% | 5.2 |
| | | 49.7 |
| Unsecured Debentures | | |
| *Guaranteed by FortisWest Inc.* | | |
| July '09 | 6.75% | 50.0 |
| Feb. '16 | 8.77% | 25.0 |
| Dec. '21 | 7.81% | 25.0 |
| *No Guarantee* | | |
| Nov. '14 | 5.48% | 140.0 |
| Nov. '35 | 5.60% | 100.0 |
| July '47 | 5.90% | 105.0 |
| | | 445.0 |
| Operating credit facilties | | 0.0 |
| Overdraft facility | | 4.0 |
| Total Debt | | 498.7 |
| Less current portion | | 5.4 |
| Long-Term Debt | | 493.2 |

* The trust deed provides for sinking fund payments of $750,000 per year for the Series E secured debentures.

As of December 31, 2007, the Company had $494.7 million (excluding the $4 million in overdrafts) of total consolidated debt outstanding, including $445 million of unsecured debentures and $49.7 million of secured debt.

The secured debt is expected to continue to account for decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series E, F and G) and three series of unsecured debentures (Series H, I and J), totalling $144.5 million (29% of total debt), are guaranteed by FortisWest Inc. (FW). FW is a direct wholly-owned subsidiary of Fortis whose sole assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding at the time that Fortis Inc. purchased the Company.

The debt profile as of December 31, 2007, is as follows:

- $44.5 million in secured debentures, Series E, F and G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company, of which one series requires sinking fund payments of $750,000 per year. These debentures mature between 2009 and 2023.
- $100 million in unsecured debentures, Series H, I and J, which are also guaranteed by FW and mature in 2009, 2035 and 2021.
- An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
- A $5.2 million mortgage on the Walden power plant, owned and operated by the Walden Power Partnership (WPP), which is secured by a pledge by FortisBC of its interest in WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

FortisBC's operating credit facility consists of:

- A $50 million, three-year revolving unsecured credit facility, maturing May 11, 2011.
- An additional $100 million, 364-day revolving unsecured credit facility, maturing on May 7, 2009. This facility may be extended for another 364 days or, if not extended, termed-out for a six-month period.
- A $10 million demand overdraft facility. As at December 31, 2007, $4 million was outstanding.

On July 4, 2007, the Company closed the issuance of $105 million senior unsecured debentures to repay existing indebtedness incurred under the bank credit facilities, and for general corporate purposes, including ongoing capital expenditures. During the year ended December 31, 2007, FortisBC borrowed and repaid $31 million by way of two 4.57% demand notes from its parent, Fortis.

FortisBC Inc.

Report Date:
April 30, 2008

**Outlook**

The Company's $160 million in bank credit facilities should provide sufficient liquidity to meet any short-term funding requirements. As at December 31, 2007, $153 million was available under the credit facilities. The debt-repayment schedule is modest, with the exception of the $54 million maturity in 2008. DBRS expects FortisBC to refinance its maturing debt, given its stable credit profile and cash flows generated from its low-risk operations.

Further, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

## Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 108,000 direct and 46,000 indirect customers, including wholesale customers such as the cities of Kelowna and Nelson. Customer growth has been steady, averaging 2% over the past five years.

Approximately 60% of power sold is to relatively stable residential and commercial customers, 11% is sold to industrial customers, and 29% is sold to wholesale customers who resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:

- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2011. As a result, total capacity has increased from 205 MW in 2004 to current levels.
- A purchase power contract with the Brilliant hydroelectric plant, which expires in 2056, supplies approximately 26% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant Power Corporation.
- Between 2000 and 2002, the Brilliant plant's turbines were upgraded, increasing their output by 125,000 MWh of energy per year. FortisBC acquires an additional 65,000 MWh of energy, as well as 20 MW of capacity from the plant under an amended PPA.
- A long-term, firm power purchase contract with BC Hydro expiring in 2013, which provides approximately 27.5% of the Company's energy needs.
- A number of small purchase power contracts with independent power producers collectively provide approximately 0.5% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

FortisBC also has a limited amount of non-regulated operations, principally made up of the Walden Power Partnership, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA which expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

In late 2007, FortisBC extended the Collective Agreement between the Company and Local 213 of the International Brotherhood of Electrical Workers (IBEW) which was due to expire on January 31, 2008, by one year to January 1, 2009.

FortisBC Inc.

Report Date:
April 30, 2008

## Regulation

### Regulatory Overview

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure, the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. Rates are based on a cost-of-service/rate-of-return methodology with some PBR-setting attributes.

FortisBC files annual rate applications for the 12-month period beginning on January 1. Through a negotiated settlement process with a group of interveners, the Company's 2008 revenue requirements were finalized and approved by the BCUC in December 2007. Key elements of the settlement include: (1) A rate increase of 2.9%, effective January 1, 2008, and (2) ROE of 9.02% (versus 8.77% for F2007), with an equity thickness of 40%.

The BCUC also approved rate increases of 3.3% and 5.9% for 2007 and 2006, respectively. The rate increases in recent years are primarily the result of the Company's extensive capital investment program and higher power purchase costs. As part of the settlement agreement approved by the BCUC in May 2006, 2006 was set as the base year for a PBR term from 2006 to 2008, with an option to continue the term into 2009. Further, as part of this agreement, the BCUC also increased the composite depreciation rate from 2.6% to 3.2%, effective January 1, 2006.

- Gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (CPI for B.C.) minus a productivity improvement factor of 2% in 2007, 2% in 2008 and 3% in 2009.
- Capitalized overhead will be set at 20% of forecast gross operating and maintenance expense.
- Positive and negative variances in interest expense are a flow-through to customers.
- A 2% collar has been set around the allowed ROE whereby all variances (except for certain variances which flow through to the customer) as a result of actual financial performance, positive or negative, will be shared equally between the customer and shareholder. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review during the next rate setting process.
- Other components of revenue requirements will be forecast annually.

The allowed ROE is linked to the forecast long-term Government of Canada (GoC) bond yield. In March 2006, the BCUC issued an order approving adjustments to the ROE mechanism, including an increase in the low-risk utility premium and the inclusion of an adjustment when the GoC bond yield is above or below 5.25%.

On November 24, 2006, the BCUC approved the 2007 and 2008 Capital Plan with six projects totalling $61.2 million subject to further approval process. As of December 31, 2007, two projects totalling $28.3 million had not yet received further approval. FortisBC plans to submit its 2009-2010 Capital Plan in mid-2008.

**FortisBC Inc.**

**Report Date:**
April 30, 2008

## FortisBC Inc.

| **Balance Sheet** ($ millions) | As at Dec. 2007 | Dec. 2006 | Dec. 2005 | **Liabilities & Equity** | As at Dec. 2007 | Dec. 2006 | Dec. 2005 |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | Short-term debt | 0.0 | 21.0 | 0.0 |
| Cash + equivalents | 0.0 | 0.0 | 6.5 | Debt due one yr. | 5.4 | 6.4 | 1.3 |
| Accounts receivable/unbilled revenue | 42.9 | 45.8 | 33.5 | A/P + accr'ds | 48.8 | 41.1 | 37.8 |
| Inventories | 0.5 | 0.7 | 0.4 | **Current Liabilities** | 54.3 | 68.5 | 39.2 |
| Other | 2.5 | 2.6 | 4.4 | Long-term debt | 440.7 | 359.6 | 338.7 |
| **Current Assets** | 45.8 | 49.1 | 44.8 | Secured debt | 48.0 | 51.1 | 52.4 |
| | | | | Capital lease obligations | 26.2 | 26.5 | 25.8 |
| Net fixed assets | 836.2 | 731.2 | 647.7 | Other l.t. liabilities | 13.2 | 11.7 | 9.2 |
| Deferred charges/Goodwill | 31.3 | 34.6 | 30.2 | Shareholders' equity | 330.9 | 297.7 | 257.5 |
| **Total** | 913.3 | 815.0 | 722.7 | **Total** | 913.3 | 815.0 | 722.7 |

| **Ratio Analysis** | For the 12-month period ended | | | | |
|---|---|---|---|---|---|
| **Liquidity Ratios** | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 |
| Current ratio | 0.84 | 0.72 | 1.15 | 0.50 | 0.29 |
| Accumulated depreciation/gross fixed assets | 22.0% | 22.7% | 22.6% | 24.0% | 26.3% |
| Cash flow/adjusted debt (1) | 11.4% | 11.2% | 10.1% | 11.3% | 10.9% |
| Cash flow/capital expenditures | 0.45 | 0.53 | 0.40 | 0.45 | 0.59 |
| Cash flow-dividends/capital expenditures | 0.37 | 0.43 | 0.33 | 0.34 | 0.40 |
| % debt in capital structure | 61.1% | 60.9% | 61.9% | 61.2% | 61.4% |
| % adjusted debt in capital structure (1) | 61.7% | 61.6% | 62.5% | 62.1% | 63.5% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| | | | | | |
| **Coverage Ratios** (1) | | | | | |
| EBIT interest coverage | 2.04 | 2.11 | 2.20 | 2.38 | 2.00 |
| EBITDA interest coverage | 3.04 | 3.09 | 2.99 | 3.15 | 2.66 |
| Fixed-charges coverage | 2.04 | 2.11 | 2.20 | 2.38 | 2.00 |
| Adjusted debt/EBITDA | 5.69 | 5.67 | 6.12 | 5.27 | 5.32 |
| | | | | | |
| **Earnings Quality/Operating Efficiency** | | | | | |
| Power purchases/revenues | 30.5% | 32.6% | 31.7% | 32.2% | 34.8% |
| EBIT margin | 28.7% | 27.6% | 27.0% | 28.1% | 25.9% |
| Net margin (before extras) | 13.8% | 12.8% | 12.9% | 12.9% | 11.4% |
| Return on avg. common equity (before extras) | 9.6% | 9.6% | 10.3% | 11.8% | 11.0% |
| Allowed ROE – mid-point | 8.77% | 9.20% | 9.43% | 9.55% | 9.82% |
| Direct customers/employee | 202 | 181 | 199 | 246 | 241 |
| Growth of customer base | 1.2% | 1.9% | 2.6% | 1.9% | 1.9% |
| Rate base ($ millions) | 747.2 | 681.0 | 590.0 | 499.0 | 443.0 |
| Growth in rate base | 9.7% | 15.4% | 18.2% | 12.6% | 10.2% |

(1) Adjusted for operating leases.

## SUMMARY OF OPERATING STATISTICS

| | For the 12-month period ended | | | | |
|---|---|---|---|---|---|
| **Generation** | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 |
| Hydro capacity (MW) | 223 | 235 | 214 | 205 | 205 |
| Gross energy generated (GWh) | 1,498 | 1,509 | 1,625 | 1,491 | 1,548 |
| Plus: purchases | 1,912 | 1,896 | 1,724 | 1,802 | 1,661 |
| Energy generated + purchased | 3,410 | 3,405 | 3,349 | 3,293 | 3,209 |
| Less: transmission losses + internal use | 320 | 365 | 378 | 388 | 347 |
| Total GWh sold | 3,090 | 3,040 | 2,971 | 2,905 | 2,862 |
| | | | | | |
| Energy lost + used/energy gen. + purch. | 9.4% | 10.7% | 11.3% | 11.8% | 10.8% |

| | For the 12-month period ended | | | | |
|---|---|---|---|---|---|
| **Electricity Sold - Breakdown*** | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 | Dec. 2003 |
| Residential | 1,160 | 1,091 | 1,068 | 1,071 | 1,013 |
| General Service | 697 | 657 | 632 | 551 | 520 |
| Industrial | 352 | 344 | 357 | 340 | 337 |
| Wholesale | 881 | 948 | 914 | 942 | 992 |
| Total - GWh sold | 3,090 | 3,040 | 2,971 | 2,905 | 2,862 |
| *Year over year growth* | 1.6% | 2.3% | 2.3% | 1.5% | 2.5% |

* Regulated only

**FortisBC Inc.**

**Report Date:**
April 30, 2008

# Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | BBB (high) | Confirmed | Stable |
| Unsecured Debentures | BBB (high) | Confirmed | Stable |

# Rating History

| | Current | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|
| Secured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | NR |

Notes:
All figures are in Canadian dollars unless otherwise noted.

**Rating Report**
**Report Date:**
June 5, 2009

**Report Date:**
April 30, 2008

Insight beyond the rating.

# FortisBC Inc.


**Analysts**
**Robert Filippazzo**
+1 416 597 7340
rfilippazzo@dbrs.com

**Michael Caranci**
+1 416 597 7304
mcaranci@dbrs.com


**The Company**
FortisBC is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 MW) on the Kootenay River in south-central B.C. and the Company provides electricity services to approximately 158,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

**Recent Actions**
**May 28, 2009**
New Issue Rated BBB (high)

**April 18, 2008**
Confirmed

## Rating

| Debt | Rating | Rating Action | Trend |
| --- | --- | --- | --- |
| Secured Debentures | BBB (high) | Confirmed | Stable |
| Unsecured Debentures | BBB (high) | Confirmed | Stable |

## Rating Rationale

DBRS has confirmed the ratings of FortisBC Inc.'s (FortisBC or the Company) Secured and Unsecured Debentures at BBB (high), with Stable trends. The rating confirmation reflects FortisBC's low business risk stemming from the regulated nature of its operations and supportive regulatory environment, its integrated operations, which include a secure low-cost hydro-based power supply portfolio and a diversified customer base, and its stable credit metrics.

The regulatory environment remains stable and supportive, providing a strong cost-of-service/rate-of-return rate setting methodology with some performance-based rate (PBR) setting attributes. The cost-of-service methodology allows for full recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formula incorporating customer growth and inflation (CPI for British Columbia) minus a productivity improvement factor (PIF) of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF, which effectively caps the CPI at 3%. The settlement agreement also resulted in a rate increase of 4.6% effective January 1, 2009. This increase is primarily the result of the Company's ongoing investment in infrastructure and rising power purchases driven by customer growth and increased demand for electricity. Rates for 2009 reflect an allowed return on equity (ROE) of 8.87% on its 60%/40% deemed capital structure. (Continued on page 2.)

## Rating Considerations

**Strengths**
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

**Challenges**
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Comparatively small size

## Financial Information

| | 12 mos. Ending | For the 12-month period ended | | | |
| --- | --- | --- | --- | --- | --- |
| ($ millions) | March 31, 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
| EBIT | 69.7 | 67.3 | 62.7 | 57.2 | 51.5 |
| Fixed-charges coverage (times) | 2.12 | 2.05 | 2.04 | 2.11 | 2.20 |
| EBITDA interest coverage | 3.18 | 3.09 | 3.04 | 3.09 | 3.00 |
| % total debt in the capital structure | 59.8% | 60.4% | 61.1% | 60.9% | 61.9% |
| % secured debt in the capital structure | 5.0% | 5.1% | 5.6% | 6.6% | 7.6% |
| Cash flow/total debt | 11.9% | 11.4% | 11.4% | 11.2% | 10.1% |
| Cash flow/capital expenditures (times) | 0.66 | 0.62 | 0.45 | 0.53 | 0.40 |
| Free cash flow | (47.6) | (45.6) | (73.3) | (67.4) | (80.1) |
| Approved ROE | 8.87% | 9.02% | 8.77% | 9.20% | 9.43% |

FortisBC Inc.

Report Date:
June 5, 2009

## Rating Rationale (Continued from page 1.)

The Company's elevated capital expenditure program, which has been ongoing for several years and is expected to be approximately $700 million over the next five years, is projected to cause continuing free cash flow deficits over the medium term. The primary focus of this large capital program continues to be the improvement of the transmission and distribution systems in order to meet the growth in demand and need for increased reliability in the Company's service territory. The resulting free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent, Fortis Inc. (Fortis, rated BBB (high), see separate DBRS rating report) to maintain its current credit profile and capital structure at the regulatory-approved levels. Fortis is a diversified, international utility holding company with investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

DBRS expects the key credit ratios to remain stable over the next few years before showing modest improvement as capital expenditures level off. Despite the continuing free cash flow deficits over the near to medium term, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. With its $160 million in bank credit facilities, FortisBC's liquidity is considered sufficient to meet any short-term funding requirements.

## Rating Considerations Details

**Strengths**

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a return on its investments. The Company has operated under a PBR mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River system, with a total generating capacity of 223 MW, which provide about 45% of energy and 30% of FortisBC's capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing from this portfolio the water flow risk that is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licenses and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts including: (a) a long-term "take or pay" contract with Brilliant Power Corporation (Brilliant, rated A (high) with a Stable trend; see separate DBRS rating report dated October 15, 2008). The contract runs until 2056 and supplies low-cost power representing close to 28% of the Company's energy needs; and (b) a power purchase contract with the government-owned British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated May 23, 2008). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating renewal of the contract. As it currently stands, approximately 98% of FortisBC's energy requirements are met through the combination of owned generation and these supply sources. However, approximately 80% of its peak capacity requirements are met through these same resources. The balance of supply is met through small power purchase contracts and spot market purchases. Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (which account for approximately 2% of the Company's energy load requirements) are passed through to customers as well. The Company has made various types of advance purchases, including capacity purchases, call options and fixed price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2008, electricity sales to stable residential customers accounted for about 40% of total sales volume, while 23% of sales were to commercial customers and 29% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 8% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impacts of an economic downturn.

**FortisBC Inc.**

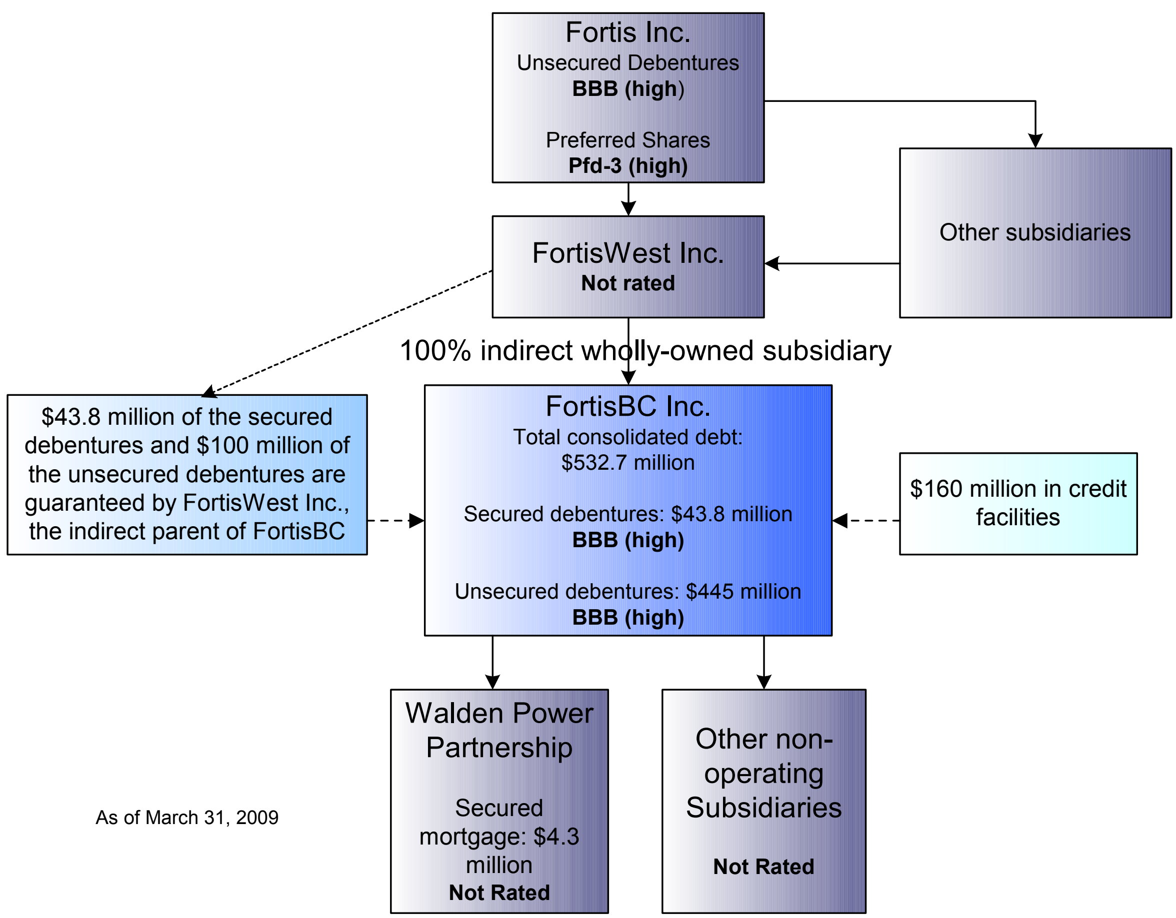
**Report Date:**
June 5, 2009

**Challenges**
(1) FortisBC's financial profile continues to be affected by free cash flow deficits due to the ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's capital expenditure program has been ongoing for several years and is expected to be approximately $700 million in projects over the next five years. Over the next few years, internal cash flow generation (net of dividends) will continue to fund the majority of capital expenditures, with the remainder financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining a capital structure at the regulatory-approved 60%/40%. The Company will need to seek some external debt financing during this stage of capital growth, which will likely keep key coverage ratios relatively flat during this period. Fortis is expected to provide equity support as needed in order to maintain the Company's regulatory-approved capital structure.

(2) The Company faces execution risk with regard to its large capital expenditure program over the next five years. The focus will be on improving the strength and reliability of the transmission and distribution system – in view of the strong growth in FortisBC's service territory – and also on completing projects on budget. However, it should be noted that the Company is already a number of years into the current capital expenditure program, with many projects already complete.

(3) FortisBC is a small utility compared with the dominant utility in the province, the Crown-owned BC Hydro, and serves a rural and low-population density region in south-central British Columbia. To some extent, the small size and franchise area limit opportunities for growth, operating efficiencies, and economies of scale as they relate to PBR.

## Simplified Ownership/Debt Chart



## Earnings and Outlook

| ($ millions) | 12 mos. Ending March 31, 2009 | For the 12-month period ended Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
|---|---|---|---|---|---|
| Revenues | 234.8 | 229.2 | 219.7 | 210.4 | 199.2 |
| EBITDA | 105.0 | 101.5 | 93.8 | 84.1 | 70.3 |
| EBIT | 69.7 | 67.3 | 62.7 | 57.2 | 51.5 |
| Gross interest expense | 32.5 | 32.4 | 30.4 | 26.7 | 23.0 |
| Core net income | 34.2 | 32.7 | 30.1 | 26.5 | 24.6 |
| Net income (reported) | 34.2 | 32.7 | 30.1 | 26.5 | 23.5 |
| Return on average common equity | 9.2% | 9.4% | 9.6% | 9.5% | 10.3% |
| | | | | | |
| Rate Base | 908.0 | 822.8 | 747.2 | 676.0 | 591.5 |
| Growth in Rate Base | 10.4% | 10.1% | 10.5% | 14.3% | 18.5% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Approved ROE | 8.87% | 9.02% | 8.77% | 9.20% | 9.43% |

**Summary**

FortisBC has historically demonstrated strong and stable growth in EBITDA and EBIT, reflective of its expanding customer base and rate base, somewhat offset by declining allowed ROEs. FortisBC's operations are almost 100% regulated, providing strong stability to earnings and cash flows. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the majority of the Company's margin.

Electricity revenues increased for the 12 months ending March 31, 2009, as a result of rate increases approved by the BCUC, as well as an increase in electricity sales throughout the year. The higher earnings in 2008 were due to increased electricity revenue, partially offset by increases to power purchases, operating expenses, depreciation and amortization, interest expense and income taxes and a decrease in other revenue.

The impact of power price volatility on earnings is limited, as power procurement-related costs are passed through to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply approximately 98% of FortisBC's power load requirements are automatically passed through to customers. The remaining 2% is procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed through to customers as well. The Company has made various types of advance market purchases, including capacity purchases and fixed price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

Interest expense has risen as a result of increased borrowings sourced to finance the large capital expenditure program partially offset by lower interest rates on bank credit facilities; however, coverage ratios continue to remain fairly stable due to earnings growth.

**Outlook**

DBRS expects EBIT and net income to continue to grow over the medium term, driven by addition of capital assets which are necessary to ensure dependable service to a growing customer base, as well as public and employee safety with an upgraded system. Other factors driving demand are the upcoming 2010 Olympics, airport expansion and provincial infrastructure investments in the Company's service area. This will result in a growing rate base related to large capital projects, including electricity transmission upgrades, substation and terminal development and turbine upgrades.

Key credit metrics are expected to remain relatively stable over the next few years before showing modest improvement, along with free cash flow deficits, as capital expenditures level off.

**FortisBC Inc.**

**Report Date:**
June 5, 2009

## Financial Profile

| ($ millions) | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Cash Flow Statement** | March 31, 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
| Core net income | 34.2 | 32.7 | 30.1 | 26.5 | 24.6 |
| Depreciation and amortization | 35.3 | 34.2 | 31.1 | 26.9 | 18.8 |
| Other non-cash adjustments | (1.4) | (1.8) | (0.1) | (0.1) | (0.1) |
| **Cash Flow From Operations** | 68.1 | 65.1 | 61.0 | 53.3 | 43.4 |
| Common dividends | (13.7) | (13.4) | (11.8) | (10.2) | (8.0) |
| Capital expenditures | (103.7) | (105.3) | (134.2) | (101.1) | (108.0) |
| **Free Cash Flow Before W/C Changes** | (49.4) | (53.6) | (85.0) | (58.0) | (72.6) |
| Net changes in working capital | 1.8 | 8.1 | 11.7 | (9.4) | (7.5) |
| **Net Free Cash Flow** | (47.6) | (45.6) | (73.3) | (67.4) | (80.1) |
| Other investing activities | (1.2) | (2.2) | (0.1) | (2.8) | (1.0) |
| Other adjustments | 0.3 | 0.3 | (0.6) | 2.8 | (3.2) |
| **Amount to be Financed** | (48.4) | (47.4) | (74.0) | (67.4) | (84.3) |
| Net debt financing | 33.3 | 32.5 | 60.2 | 40.9 | 69.9 |
| Net equity financing | 15.0 | 15.0 | 15.0 | 20.0 | 21.5 |
| Other financing | 0.0 | (0.0) | (1.2) | 0.0 | (1.5) |
| **Net Change in Cash** | (0.1) | 0.0 | (0.0) | (6.5) | 5.5 |
| | | | | | |
| % debt in capital structure | 59.8% | 60.4% | 61.1% | 60.9% | 61.9% |
| EBIT interest coverage (times) | 2.12 | 2.05 | 2.04 | 2.11 | 2.20 |
| Cash flow/total debt | 11.9% | 11.4% | 11.4% | 11.2% | 10.1% |
| Total debt to EBITDA (times) | 5.45 | 5.60 | 5.69 | 5.67 | 6.11 |
| Dividend payout ratio | 40.0% | 41.0% | 39.3% | 38.5% | 32.5% |

### Summary

FortisBC's cash flow from operations has historically displayed underlying stability and growth due to both earnings and investment in plants. The increase in depreciation expense in recent years can be attributed to a larger depreciable asset base and a change in the estimated composite depreciation rate from 2.6% to 3.2%, effective January 1, 2006.

Cash flow from operations has risen on account of increases in cash provided by net earnings, depreciation, and non-cash working capital.

Although FortisBC continues to maintain strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits, which are financed with a combination of incremental debt and equity from Fortis with the target of maintaining capital structure at the regulatory-approved 60%/40%.

Overall, the Company has maintained a reasonable financial profile, reflecting a solid and stable balance sheet and adequate credit metrics for the rating.

### Outlook

The Company will continue to generate free cash flow deficits over the medium term as it continues to invest heavily in the improvement of the transmission and distribution systems in order to meet the strong growth in its service territory. Annual capital expenditures are expected to remain high, with approximately $700 million in projects planned over the next five years. Annual average capital expenditures are expected to create financing requirements, after dividends, in the $40 million to $100 million range annually, which DBRS expects will be financed with incremental debt and equity from Fortis. Capital expenditures should peak in the near term and level off around 2012; we expect cash flow from operations to be largely adequate to fund future capital expenditures.

Free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent to maintain leverage at the regulatory-approved levels. Thus, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat during this elevated capital program period, as increased debt levels will be offset by higher earnings on a growing rate base.

**FortisBC Inc.**

**Report Date:**
June 5, 2009

## Long-Term Debt Maturities and Liquidity

as at March 31, 2009

| Maturity Schedule ($MM) | 2010 | 2011 | 2012 | 2013 | 2014 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 54.5 | 0.9 | 36.9 | 16.0 | 0.7 | 420.0 | 529.0 |

Debt Chart ($millions)

| | | | Mar. '09 |
|---|---|---|---|
| Secured Debentures | | | |
| *Guaranteed by FortisWest Inc.* | | | |
| | * Dec. '09 | 11.0% | 3.7 |
| | Oct. '12 | 9.65% | 15.0 |
| | Aug. '23 | 8.80% | 25.0 |
| WPP Mortgage | | | |
| | Oct. '13 | 9.44% | 4.3 |
| | | | 48.0 |
| Unsecured Debentures | | | |
| *Guaranteed by FortisWest Inc.* | | | |
| | July '09 | 6.75% | 50.0 |
| | Feb. '16 | 8.77% | 25.0 |
| | Dec. '21 | 7.81% | 25.0 |
| *No Guarantee* | | | |
| | Nov. '14 | 5.48% | 140.0 |
| | Nov. '35 | 5.60% | 100.0 |
| | July '47 | 5.90% | 105.0 |
| | | | 445.0 |
| Operating credit facilties | | | 36.0 |
| Overdraft facility | | | 3.7 |
| Total Debt | | | 532.7 |
| Less current portion | | | 58.2 |
| Long-Term Debt | | | 474.5 |

* The trust deed provides for sinking fund payments of $750,000 per year for the Series E secured debentures.

As of March 31, 2009, the Company had $529 million (excluding the $3.7 million in overdrafts) of total consolidated debt outstanding, including $445 million of unsecured debentures, $48 million of secured debt, and $36 million of credit facilities.

The secured debt is expected to continue to account for a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series E, F and G) and three series of unsecured debentures (Series H, I and J), totalling $143.8 million (27% of total debt), are guaranteed by FortisWest Inc. (FW). FW is a direct wholly-owned subsidiary of Fortis, whose sole assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding at the time that Fortis Inc. purchased the Company.

The debt profile as of March 31, 2009, is as follows:

– $43.8 million in secured debentures, Series E, F and G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company, of which one series requires sinking fund payments of $750,000 per year. These debentures mature between 2009 and 2023.
– $100 million in unsecured debentures, Series H, I and J, which are also guaranteed by FW and mature in 2009, 2016 and 2021.
– An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
– A $4.3 million mortgage on the Walden power plant, owned and operated by the Walden Power Partnership (WPP), which is secured by a pledge by FortisBC of its interest in the WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

FortisBC's operating credit facility consists of:

– A $50 million, three-year revolving unsecured credit facility, maturing May 11, 2011.
– An additional $100 million, 364-day revolving unsecured credit facility, maturing on May 7, 2009. This facility may be extended for another 364 days or, if not extended, termed out for a six-month period.
– A $10 million demand overdraft facility. As at March 31, 2009, $3.7 million was outstanding.

During the first quarter of 2009, a syndicate of Canadian chartered banks unanimously consented to the Company's request to extend the $50 million, three-year revolving unsecured credit facility maturity date to May 9, 2012, and the $100 million, 364-day revolving unsecured credit facility maturity date to May 6, 2010, and certain other amendments to its operating credit facility. An amended agreement was finalized during the second quarter of 2009.

**Outlook**

The Company's $160 million in bank credit facilities should provide sufficient liquidity to meet any short-term funding requirements. As at March 31, 2009, $117.3 million was available under the credit facilities. The debt repayment schedule is modest. DBRS expects FortisBC to refinance its maturing debt, given its stable credit profile and cash flows generated from its low-risk operations.

The Company successfully executed a $105 million Medium-Term Note issue on June 2, 2009, which will be used in part to repay the $54 million debt maturity in 2009. The remainder of the proceeds will be used to fund the Company's ongoing capital expenditure plan and for general corporate purposes.

Furthermore, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

## Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 110,000 direct and 47,500 indirect customers, including wholesale customers such as the cities of Kelowna and Nelson. Customer growth has been steady, averaging 2% over the past five years.

Approximately 63% of power sold is to relatively stable residential and commercial customers, 8% is sold to industrial customers, and 29% is sold to wholesale customers who resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:

- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012. As a result, total capacity has increased from 205 MW in 2004 to current levels.
- A purchase power contract with the Brilliant hydroelectric plant, which expires in 2056, supplies approximately 28% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant.
- Between 2000 and 2002, the Brilliant plant's turbines were upgraded, increasing their output by 125,000 MWh of energy per year. FortisBC acquires an additional 65,000 MWh of energy, as well as 20 MW of capacity from the plant, under an amended PPA.
- A long-term, firm power purchase contract with BC Hydro expiring in 2013, which provides approximately 24.5% of the Company's energy needs.
- A number of small purchase power contracts with independent power producers collectively provide approximately 1% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

FortisBC also has a limited amount of non-regulated operations, principally made up of the WPP, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

## Regulation

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure, the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. Rates are based on a cost-of-service/rate-of-return methodology with some PBR-setting attributes.

FortisBC files annual rate applications for the 12-month period beginning on January 1. Through a negotiated settlement process with a group of intervenors, the Company's 2009 revenue requirements were finalized and approved by the BCUC in December 2008. Key elements of the settlement include: (1) A rate increase of 4.6%, effective January 1, 2009, and (2) ROE of 8.87% (versus 9.02% for F2008), with an equity thickness of 40%.

The BCUC also approved rate increases for 2008, 2.9% effective as of January 1, 2008, a 0.8% increase that took effect May 1, 2008, 3.3% increase for 2007 and a 5.9% increase for 2006. The rate increases in recent years are primarily the result of the Company's extensive capital investment program and higher power purchase costs. As part of the settlement agreement approved by the BCUC in May 2006, 2006 was set as the base year for a PBR term from 2006 to 2008, with an option to continue the term into 2009. Further, as part of this agreement, the BCUC also increased the composite depreciation rate from 2.6% to 3.2%, effective January 1, 2006.

The significant terms of the PBR agreement are as follows:

- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (CPI for British Columbia) minus a productivity improvement factor (PIF) of 2% in 2007, 2% in 2008 and, if applicable, 3% in 2009;
- Annual capitalized overhead will be set at 20% of the BCUC-approved gross operating and maintenance expense;
- Other components of revenue requirements will be forecast annually; and
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally between customers and the shareholder. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review and disposition during the next rate setting process. The Company's portion of the incentive is subject to the Company meeting certain performance standards and BCUC approval.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formulae incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF which effectively caps the CPI at 3%.

The allowed ROE is linked to the forecast long-term Government of Canada (GoC) bond yield. In March 2006, the BCUC issued an order approving adjustments to the ROE mechanism, including an increase in the low-risk utility premium and the inclusion of an adjustment when the GoC bond yield is above or below 5.25%.

On June 27, 2008, FortisBC applied to the BCUC for approval of its 2009-2010 Capital Expenditure Plan (2009-2010 CEP). On February 27, 2009, the BCUC approved 2009 capital expenditures of approximately $151.0 million (net of $14.0 million in customer contributions) and 2010 capital expenditures of approximately $141.0 million (net of $15.0 million in customer contributions). An additional $16.0 million is subject to further regulatory processes. The capital expenditures are necessary to ensure the ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base. The most significant areas of expenditure are those required to expand and upgrade the bulk transmission and distribution system to keep pace with load growth, and to continue the life extension program at FortisBC's generating plants.

**FortisBC Inc.**

**Report Date:**
June 5, 2009

## FortisBC Inc.

| **Balance Sheet** | 12 mos. Ending | As at | | | 12 mos. Ending | As at | |
|---|---|---|---|---|---|---|---|
| ($ millions) | March 31, 2009 | Dec. 2008 | Dec. 2007 | **Liabilities & Equity** | March 31, 2009 | Dec. 2008 | Dec. 2007 |
| **Assets** | | | | Short-term debt | 0.0 | 0.0 | 0.0 |
| Cash + equivalents | 0.1 | 0.0 | 0.0 | Debt due one yr. | 58.2 | 61.8 | 5.4 |
| Accounts receivable/unbilled revenue | 37.8 | 37.3 | 42.9 | A/P + accr'ds | 54.8 | 51.9 | 48.8 |
| Inventories | 0.7 | 0.7 | 0.5 | **Current Liabilities** | 113.0 | 113.7 | 54.3 |
| Other | 4.8 | 2.1 | 2.5 | Long-term debt | 423.1 | 418.0 | 440.7 |
| **Current Assets** | 43.3 | 40.2 | 45.8 | Secured debt | 47.3 | 47.5 | 48.0 |
| | | | | Capital lease obligations | 28.8 | 28.7 | 26.2 |
| Net fixed assets | 898.3 | 909.0 | 836.2 | Other l.t. liabilities | 99.5 | 12.6 | 13.2 |
| Deferred charges/Goodwill | 144.7 | 36.4 | 31.3 | Shareholders' equity | 374.8 | 365.2 | 330.9 |
| **Total** | 1086.4 | 985.6 | 913.3 | **Total** | 1086.4 | 985.6 | 913.3 |

| **Ratio Analysis** | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Liquidity Ratios** | March 31, 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
| Current ratio | 0.38 | 0.35 | 0.84 | 0.72 | 1.15 |
| Accumulated depreciation/gross fixed assets | 20.4% | 22.1% | 22.0% | 22.7% | 22.6% |
| Cash flow/adjusted debt (1) | 11.9% | 11.4% | 11.4% | 11.2% | 10.1% |
| Cash flow/capital expenditures | 0.66 | 0.62 | 0.45 | 0.53 | 0.40 |
| Cash flow-dividends/capital expenditures | 0.52 | 0.49 | 0.37 | 0.43 | 0.33 |
| % debt in capital structure | 59.8% | 60.4% | 61.1% | 60.9% | 61.9% |
| % adjusted debt in capital structure (1) | 60.4% | 60.9% | 61.7% | 61.6% | 62.5% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| | | | | | |
| **Coverage Ratios** (1) | | | | | |
| EBIT interest coverage | 2.12 | 2.05 | 2.04 | 2.11 | 2.20 |
| EBITDA interest coverage | 3.18 | 3.09 | 3.04 | 3.09 | 3.00 |
| Fixed-charges coverage | 2.12 | 2.05 | 2.04 | 2.11 | 2.20 |
| Adjusted debt/EBITDA | 5.45 | 5.60 | 5.69 | 5.67 | 6.11 |
| | | | | | |
| **Earnings Quality/Operating Efficiency** | | | | | |
| Power purchases/revenues | 29.6% | 29.7% | 31.0% | 33.5% | 34.6% |
| EBIT margin | 29.7% | 29.4% | 28.5% | 27.2% | 25.8% |
| Net margin (before extras) | 14.6% | 14.2% | 13.7% | 12.6% | 12.3% |
| Return on avg. common equity (before extras) | 9.2% | 9.4% | 9.6% | 9.5% | 10.3% |
| Allowed ROE – mid-point | 8.87% | 9.02% | 8.77% | 9.20% | 9.43% |
| Direct customers/employee | 202 | 201 | 202 | 181 | 199 |
| Growth of customer base | 0.7% | 2.1% | 1.0% | 1.9% | 2.6% |
| Rate base ($ millions) | 908.0 | 822.8 | 747.2 | 676.0 | 591.5 |
| Growth in rate base | 10.4% | 10.1% | 10.5% | 14.3% | 18.5% |

(1) Adjusted for operating leases.

## SUMMARY OF OPERATING STATISTICS

| | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Generation** | March 31, 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
| Hydro capacity (MW) | 223 | 223 | 223 | 235 | 214 |
| Gross energy generated (GWh) | 1,579 | 1,610 | 1,498 | 1,509 | 1,625 |
| Plus: purchases | 1,847 | 1,790 | 1,912 | 1,896 | 1,724 |
| Energy generated + purchased | 3,426 | 3,400 | 3,410 | 3,405 | 3,349 |
| Less: transmission losses + internal use | 310 | 313 | 320 | 365 | 378 |
| Total GWh sold | 3,116 | 3,087 | 3,090 | 3,040 | 2,971 |
| | | | | | |
| Energy lost + used/energy gen. + purch. | 9.0% | 9.2% | 9.4% | 10.7% | 11.3% |

| | For the 12-month period ended | | | | |
|---|---|---|---|---|---|
| **Electricity Sold - Breakdown*** | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 | Dec. 2004 |
| Residential | 1,221 | 1,160 | 1,091 | 1,068 | 1,071 |
| General Service | 722 | 697 | 657 | 632 | 551 |
| Industrial | 252 | 352 | 344 | 357 | 340 |
| Wholesale | 892 | 881 | 948 | 914 | 942 |
| Total - GWh sold | 3,087 | 3,090 | 3,040 | 2,971 | 2,905 |
| *Year over year growth* | -0.1% | 1.6% | 2.3% | 2.3% | 1.5% |

* Regulated only

**FortisBC Inc.**

**Report Date:**
June 5, 2009

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | BBB (high) | Confirmed | Stable |
| Unsecured Debentures | BBB (high) | Confirmed | Stable |

## Rating History

| | Current | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| Secured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |

Note:
All figures are in Canadian dollars unless otherwise noted.

**Rating Report**
**Report Date:**
October 26, 2010
**Report Date:**
June 5, 2009

# FortisBC Inc.

Insight beyond the rating.

**Analysts**
**Robert Filippazzo**
+1 416 597 7340
rfilippazzo@dbrs.com

**Michael Caranci**
+1 416 597 7304
mcaranci@dbrs.com

**The Company**
FortisBC is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 MW) on the Kootenay River in south-central B.C. and the Company provides electricity services to approximately 160,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

**Recent Actions**
**October 1, 2010**
Upgraded

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Upgraded | Stable |
| Unsecured Debentures | A (low) | Upgraded | Stable |

## Rating Rationale

On October 1, 2010, DBRS upgraded the ratings of FortisBC Inc.'s (FortisBC or the Company) Secured and Unsecured Debentures to A (low) from at BBB (high). The trends on both ratings are maintained at Stable. Rather than by one defining event, the upgrade was driven by a number of factors, including: 1) the Company is well through its large capital expenditure program, which has been ongoing for several years, and has demonstrated an ability to execute as planned; 2) FortisBC has maintained stable credit metrics over the past five years, despite the continued capital expenditure-driven free cash flow deficits; 3) a continued supportive regulatory environment; 4) the Company's increased size and scale; and 5) strong parental support from Fortis Inc. over the years, as demonstrated by consistent equity injections to maintain FortisBC's financial profile.

As FortisBC has successfully invested considerable capital (increasing total assets by approximately 65% since 2005) and continues to invest sums considerably in excess of cash flow levels, the Company's credit metrics have nonetheless remained extremely resilient. This can be attributed largely to the fact that most expenditures have been concentrated in the distribution business, where invested capital generally enters rate base (and earnings begin) reasonably quickly. The primary focus of the capital program is for the expansion and improvement of FortisBC's transmission and distribution systems in order to meet demand growth and achieve increased reliability. The elevated capital expenditures may approach $650 million (net of customer contributions) over the next five years, resulting in free cash flow deficits that will continue to be funded with a combination of incremental debt financing and equity support from parent company Fortis Inc. to maintain its capital structure at the regulatory-approved levels. Fortis Inc. has in the past regularly invested incremental equity in FortisBC as needed. (Continued on page 2.)

## Rating Considerations

**Strengths**
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

**Challenges**
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Earnings and cash flow affected by lower ROEs

## Financial Information

| ($ millions) | 12 mos. Ending June 30, 2010 | For the 12-month period ended Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
|---|---|---|---|---|---|---|
| EBIT | 74.2 | 73.0 | 67.3 | 62.7 | 57.2 | 51.5 |
| EBIT interest coverage | 2.03 | 2.04 | 2.05 | 2.04 | 2.11 | 2.20 |
| EBITDA interest coverage | 3.09 | 3.06 | 3.09 | 3.04 | 3.09 | 3.00 |
| % total debt in the capital structure | 60.4% | 60.4% | 60.4% | 61.1% | 60.9% | 61.9% |
| Cash flow/total debt | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% | 10.1% |
| Cash flow/capital expenditures (times) | 0.60 | 0.69 | 0.62 | 0.45 | 0.53 | 0.40 |
| Free cash flow | (55.6) | (55.3) | (45.6) | (73.3) | (67.4) | (80.1) |
| Approved ROE | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% | 9.43% |

**FortisBC Inc.**

**Report Date:**
October 26, 2010

## Rating Rationale (Continued from page 1.)

DBRS notes that it has also resolved the Positive trend assigned to Fortis Inc.'s Unsecured Debentures and Preferred Shares, upgrading the ratings to A (low) and Pfd-2 (low), respectively, and changing its trends to Stable (see October 1, 2010 press release).

The regulatory environment remains stable and supportive, providing a strong cost-of-service/rate-of-return rate-setting methodology with some performance-based rate (PBR) setting attributes. The cost-of-service framework allows for full recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame. The British Columbia Utilities Commission (BCUC) approved a settlement agreement pertaining to the Company's 2010 rates, which incorporated the expected increase in FortisBC's return on equity (ROE) to 9.90%, up from 8.87% in 2009. The ROE increase stemmed from a positive 2009 decision which also determined that the automatic adjustment mechanism that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined will apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. While the increase in ROE is positive, there does remain uncertainty as to when and how ROE levels will be adjusted in the future.

The capital expenditure program has resulted in the Company exhibiting growth that is considered strong for a regulated utility, with the rate base growing at approximately 10% per year over the past five years. The Company's increased size, with total assets of approximately $1.2 billion, should provide it with improved economies of scale, operating efficiencies and access to capital. While DBRS had in the past viewed FortisBC's size as a negative factor, this is no longer a material issue given its now-larger presence.

DBRS expects key credit metrics to improve modestly over the coming years as a result of the recent favourable regulatory decisions, as capital assets are added to rate base, and as capital expenditures level off.

## Rating Considerations Details

**Strengths**

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a return on its investments. The Company has operated under a PBR mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River system, with a total generating capacity of 223 megawatts (MW), which provide about 45% of energy and 30% of FortisBC's capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing from this portfolio the water flow risk that is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licenses and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts including: (a) a long-term "take or pay" contract with Brilliant Power Corporation (Brilliant, rated A (high) with a Stable trend; see separate DBRS rating report dated September 16, 2009). The contract runs until 2056 and supplies low-cost power representing close to 28% of the Company's energy needs; and (b) a power purchase contract with the government-owned British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated December 1, 2009). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating renewal of the contract. As it currently stands, approximately 95% of FortisBC's energy requirements are met through the combination of owned generation and these supply sources. However, approximately 80% of its peak capacity requirements are met through these same resources. The balance of supply is met through small power purchase contracts and spot market purchases.

Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (which account for approximately 5% of the Company's energy load requirements) are passed through to customers as well. The Company has made various types of advance purchases, including capacity purchases, call options and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2009, electricity sales to stable residential customers accounted for about 41% of total sales volume, while 23% of sales were to commercial customers and 30% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 6% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impacts of an economic downturn.

**Challenges**

(1) FortisBC's financial profile continues to be affected by free cash flow deficits due to the ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's capital expenditure program has been ongoing for several years and is expected to be approximately $650 million (net of customer contributions) in projects over the next five years. Over the next few years, internal cash flow generation (net of dividends) will continue to fund the majority of capital expenditures. The remainder will be financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining a capital structure at the regulatory-approved 60%/40%. The Company will need to seek some external debt financing during this stage of capital growth, which will likely keep key coverage ratios relatively flat during this period. Fortis is expected to provide equity support as needed in order to maintain the Company's regulatory-approved capital structure.

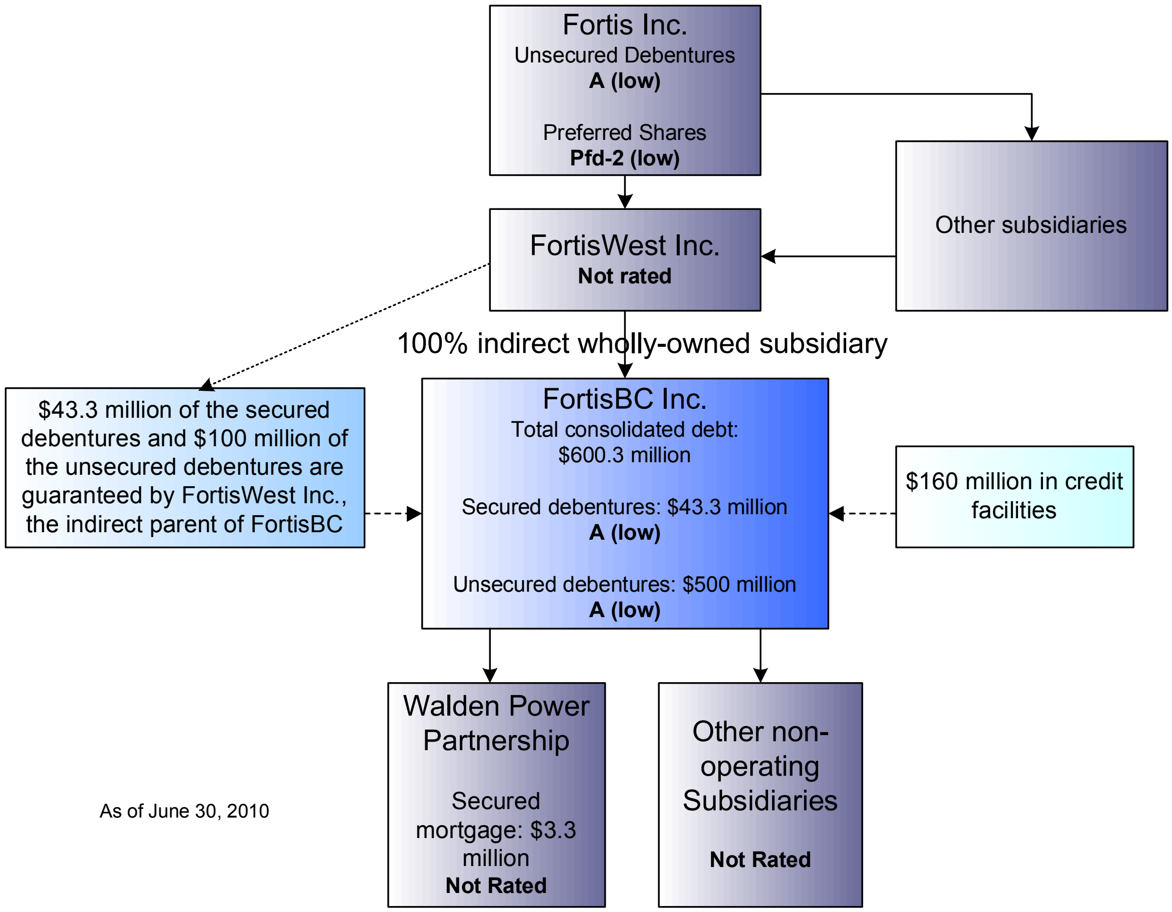
(2) The Company faces execution risk with regard to its large capital expenditure program over the next five years. The focus will be on improving the strength and reliability of the transmission and distribution system – in view of the strong growth in FortisBC's service territory – and also on completing projects on budget. However, it should be noted that the Company is already a number of years into the current capital expenditure program, with many projects already complete.

(3) Although the BCUC terminated the automatic adjustment ROE formula and set FortisBC's approved level at 9.9% (effective January 1, 2010), it had been in the low 9% and below since 2007. While FortisBCs ROE is now set at a benchmark level plus 40 basis points (bps), the absolute increase in the benchmark level (being Terasen Gas Inc.'s (TGI) ROE, which rose to 9.50%) drove the increase in FortisBC's to the 9.9% level. With the use of the automatic adjustment formula having been terminated, there is uncertainty as to how ROE levels will be determined in the medium and longer term; the BCUC has directed TGI to investigate alternative mechanisms.

**FortisBC Inc.**

**Report Date:**
October 26, 2010

## Simplified Ownership/Debt Chart



## Earnings and Outlook

| ($ millions) | 12 mos. Ending June 30, 2010 | For the 12-month period ended Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
|---|---|---|---|---|---|
| Revenues | 246.7 | 244.1 | 229.2 | 219.7 | 207.6 |
| EBITDA | 113.5 | 110.1 | 101.5 | 93.8 | 84.1 |
| EBIT | 74.2 | 73.0 | 67.3 | 62.7 | 57.2 |
| Gross interest expense | 36.4 | 35.4 | 32.4 | 30.4 | 26.7 |
| Core net income | 37.1 | 36.2 | 32.7 | 30.1 | 26.5 |
| Net income (reported) | 37.1 | 36.2 | 32.7 | 30.1 | 26.5 |
| Return on average common equity | 9.2% | 9.5% | 9.4% | 9.6% | 9.5% |
| | | | | | |
| Rate Base | 949.0 | 867.7 | 822.8 | 747.2 | 676.0 |
| Growth in Rate Base | 15.3% | 5.5% | 10.1% | 10.5% | 14.3% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Approved ROE | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |

**Summary**

FortisBC has historically demonstrated strong and stable growth in EBITDA and EBIT, reflective of its expanding customer base and rate base. FortisBC's operations are almost 100% regulated, providing strong stability to earnings and cash flows. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the majority of the Company's margin.

Electricity revenues increased for the 12 months ending June 30, 2010, as a direct result of rate increases approved by the BCUC, as well as an increase in electricity sales throughout the period. Sales increased as a result of favourable growth in the majority of the Company's customer classes.

The increase in interest expense for the 12 months ending June 30, 2010, and year ending 2009, is primarily due to increased borrowings sourced to finance the large capital expenditure program, although this increase was partially offset by lower interest rates on bank credit facilities. Nonetheless, coverage ratios remain fairly stable due to earnings growth.

The impact of power price volatility on earnings is limited, as power procurement-related costs are passed on to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply approximately 95% of FortisBC's power load requirements are automatically passed through to customers. The remaining 5% is procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed through to customers as well. The Company has made various types of advance market purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

**Outlook**

DBRS expects EBIT and net income to continue to grow over the medium term, driven by addition of capital assets as well as the increase in rate base and ROE to 9.90% for both 2010 and 2011. The investment in capital assets is necessary to ensure dependable service to a growing customer base, as well as public and employee safety with an upgraded system.

Key credit metrics are expected to increase over the coming years as capital expenditures level off and earnings and cash flows benefit from higher rates, an increased rate base and ROE.

## Financial Profile

| ($ millions) | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Cash Flow Statement** | June 30, 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
| Core net income | 37.1 | 36.2 | 32.7 | 30.1 | 26.5 |
| Depreciation and amortization | 39.7 | 37.5 | 34.2 | 31.1 | 26.9 |
| Other non-cash adjustments | 1.7 | 2.0 | (1.8) | (0.1) | (0.1) |
| **Cash Flow From Operations** | 78.6 | 75.7 | 65.1 | 61.0 | 53.3 |
| Common dividends | (14.5) | (14.5) | (13.4) | (11.8) | (10.2) |
| Capital expenditures | (130.2) | (110.2) | (105.3) | (134.2) | (101.1) |
| **Free Cash Flow Before W/C Changes** | (66.1) | (49.0) | (53.6) | (85.0) | (58.0) |
| Net changes in working capital | 10.5 | (6.3) | 8.1 | 11.7 | (9.4) |
| **Net Free Cash Flow** | (55.6) | (55.3) | (45.6) | (73.3) | (67.4) |
| Other investing activities | 4.6 | (2.8) | (2.2) | (0.1) | (2.8) |
| Other adjustments | (0.6) | (0.6) | 0.3 | (0.6) | 2.8 |
| **Amount to be Financed** | (51.7) | (58.7) | (47.4) | (74.0) | (67.4) |
| Net debt financing | 2.1 | 49.7 | 32.5 | 60.2 | 40.9 |
| Net equity financing | 10.0 | 10.0 | 15.0 | 15.0 | 20.0 |
| Other financing | 0.0 | (1.0) | (0.0) | (1.2) | 0.0 |
| **Net Change in Cash** | (39.5) | (0.0) | 0.0 | (0.0) | (6.5) |
| | | | | | |
| % debt in capital structure | 60.4% | 60.4% | 60.4% | 61.1% | 60.9% |
| EBIT interest coverage (times) | 2.03 | 2.04 | 2.05 | 2.04 | 2.11 |
| Cash flow/total debt | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% |
| Total debt to EBITDA (times) | 5.59 | 5.64 | 5.60 | 5.69 | 5.67 |
| Dividend payout ratio | 39.0% | 40.0% | 41.0% | 39.3% | 38.5% |

### Summary

FortisBC's cash flow from operations has historically displayed underlying stability and growth due to both earnings and investment in plants. The increase in depreciation expense in recent years can be attributed to a growing depreciable asset base as capital assets are added to rate base.

Cash flow from operations has risen on account of increases in cash provided by net earnings and depreciation.

Although FortisBC maintains strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits, which are financed with a combination of incremental debt and equity from Fortis, with the target of maintaining capital structure at the regulatory-approved 60%/40%. DBRS notes that the Company's deficits have been declining as capital assets are added to rate base free cash flow.

Overall, the Company has maintained a favourable financial profile, reflecting a solid and stable balance sheet and credit metrics.

### Outlook

The Company will continue to generate free cash flow deficits over the medium term as it invests in the improvement of its transmission and distribution systems in order to meet the growth in its service territory. Annual capital expenditures are expected to remain high, with approximately $650 million in projects planned over the next five years. Annual average capital expenditures are expected to create financing requirements, after dividends, in the $40 million to $100 million range per year, which DBRS expects will be financed with incremental debt and equity from Fortis. Capital expenditures should peak in the near term and level off around 2014; we expect cash flow from operations to be largely adequate to fund future capital expenditures.

Free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent to maintain leverage at the regulatory-approved levels. Thus, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat during this elevated capital program period, as increased debt levels will be offset by higher earnings on a growing rate base.

## Long-Term Debt Maturities and Liquidity

Debt Chart (CAD millions)

| | | | June 30/10 |
|---|---|---|---|
| **Secured Debentures** | | | |
| *Guaranteed by FortisWest In* | | Rate | Amount |
| Due: | Oct. 2012 | 9.65% | 15.0 |
| | Aug. 2023 | 8.80% | 25.0 |
| **WPP Mortgage** | | | |
| | Oct. 2013 | 9.44% | 3.3 |
| | | | 43.3 |
| **Unsecured Debentures** | | | |
| *Guaranteed by FortisWest Inc.* | | | |
| | Feb. 2016 | 8.77% | 25.0 |
| | Dec. 2021 | 7.81% | 25.0 |
| *No Guarantee* | | | |
| | Nov. 2014 | 5.48% | 140.0 |
| | Nov. 2035 | 5.60% | 100.0 |
| | Jul. 2047 | 5.90% | 105.0 |
| | MTN June 2039 | 6.10% | 105.0 |
| | | | 500.0 |
| **Operating Credit Facilties** | | | 46.9 |
| **Overdraft Facility** | | | 10.1 |
| | | | |
| **Total Debt** | | | 600.3 |
| Less current portion | | | 11.0 |
| **Long-Term Debt** | | | 589.3 |

as at June 30, 2010

| Maturity Schedule ($MM) | 2010 | 2011 | 2012 | 2013 | 2014 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 0.9 | 0.9 | 62.9 | 0.5 | 140.0 | 385.0 | 590.2 |

As of June 30, 2010, the Company had $590.2 million (excluding the $10.1 million in overdrafts) of total consolidated debt outstanding, including $500 million of unsecured debentures, $43.3 million of secured debt, and $46.9 million of credit facilities.

The secured debt is expected to continue to account for a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series F and G) and the unsecured debentures (Series H and I), totaling $50 million (8.5% of total debt), are guaranteed by FortisWest Inc. (FW). FW is a direct wholly-owned subsidiary of Fortis, whose sole assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding at the time that Fortis Inc. purchased the Company.

The debt profile as of June 30, 2010, is as follows:

- $43.3 million in secured debentures, Series F and G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company. These debentures mature between 2012 and 2023.
- $50 million in unsecured debentures, Series H and I, which are also guaranteed by FW and mature in 2016 and 2021.
- An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
- A $3.3 million mortgage on the Walden power plant, owned and operated by the Walden Power Partnership (WPP), which is secured by a pledge by FortisBC of its interest in the WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

FortisBC's operating credit facility was amended in April 2010 and consists of:

- A $100 million, three-year revolving unsecured credit facility, maturing May 8, 2013.
- An additional $50 million, 364-day revolving unsecured credit facility, maturing on May 5, 2011. This facility may be extended for another 364 days or, if not extended, termed out for a six-month period.
- A $10 million demand overdraft facility.

As of June 30, 2010, $57.0 million was utilized against these facilities (December 31, 2009 - $37.8 million) and $nil (December 31, 2009 - $nil) was used to support outstanding letters of credit.

Certain of the Corporation's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 70% of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceeds thresholds based on the cumulative net earnings of the Corporation.

**Outlook**

The Company's $160 million in bank credit facilities should provide sufficient liquidity to meet any short-term funding requirements. As at June 30, 2010, $103 million was available under the credit facilities. The debt repayment schedule is modest. DBRS expects FortisBC to refinance its maturing debt, given its stable credit profile and cash flows generated from its low-risk operations.

Furthermore, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

## Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 159,000 direct and indirect customers, including wholesale customers such as the cities of Kelowna and Nelson.

Approximately 64% of power sold is to relatively stable residential and commercial customers, 6.4% is sold to industrial customers, and 29% is sold to wholesale customers who resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:

- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012. As a result, total capacity has increased from 205 MW in 2004 to current levels.
- A purchase power contract with the Brilliant hydroelectric plant, which expires in 2056, supplies approximately 28% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant.
- Between 2000 and 2002, the Brilliant plant's turbines were upgraded, increasing their output by 125,000 MWh of energy per year. FortisBC acquires an additional 65,000 MWh of energy, as well as 20 MW of capacity from the plant, under an amended PPA.
- A long-term, firm power purchase contract with BC Hydro expiring in 2013, which provides approximately 24.5% of the Company's energy needs.
- A number of small purchase power contracts with independent power producers collectively provide approximately 1% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

FortisBC also has a limited amount of non-regulated operations, principally made up of the WPP, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

In 2009, the Company sold 3,157,000 MWh of electricity to its customers, 928,000 MWh of which was purchased by FortisBC's seven wholesale customers. The Company had a peak demand of 714 MW in 2009, 32 MW lower than the historical peak demand of 746 MW.

## Regulation

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure, the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. Rates are based on a cost-of-service/rate-of-return methodology with some PBR-setting attributes.

FortisBC files annual rate applications for the 12-month period beginning on January 1. On December 18, 2009, the BCUC approved a settlement agreement pertaining to the 2010 Revenue Requirements Application. As a result of the settlement agreement, FortisBC's ROE in 2010 will be 9.90%, up from 8.87% in 2009. The BCUC also determined that the automatic adjustment mechanism that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined in the decision will apply until changed by the BCUC. Additionally, in December 2009, the BCUC approved a 6% rate increase for 2010. The increase reflected the change in revenue requirement and ROE. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. As at December 31, 2009, FortisBC had total assets of $1.15 billion and Rate Base Assets of $908 million. Rate Base Assets in the 2010 Revenue Requirements are $975 million.

The significant terms of the PBR agreement are as follows:

- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (CPI for British Columbia) minus a productivity improvement factor (PIF) of 2% in 2007, 2% in 2008 and, if applicable, 3% in 2009;
- Annual capitalized overhead will be set at 20% of the BCUC-approved gross operating and maintenance expense;
- Other components of revenue requirements will be forecast annually; and
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally between customers and the shareholder. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review and disposition during the next rate setting process. The Company's portion of the incentive is subject to the Company meeting certain performance standards and BCUC approval.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formulae incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF, which effectively caps the CPI at 3%.

On June 18, 2010, FortisBC applied to the BCUC for approval of its 2011 Capital Expenditure Plan. The plan outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and to deliver Demand Side Management programs to the Company's growing customer base. The $103.3 million plan consists of $97.5 million in capital expenditures, net of customer contributions and $5.8 million in Demand Side Management programs.

**FortisBC Inc.**

**Report Date:**
October 26, 2010

## FortisBC Inc.

| **Balance Sheet** | 12 mos. Ending | As at | |
|---|---|---|---|
| ($ millions) | June 30, 2010 | Dec. 2009 | Dec. 2008 |
| **Assets** | | | |
| Cash + equivalents | 0.4 | 0.0 | 0.0 |
| Accounts receivable/unbilled revenue | 33.8 | 41.1 | 37.3 |
| Inventories | 0.5 | 0.5 | 0.7 |
| Other | 4.1 | 3.5 | 2.1 |
| **Current Assets** | 38.7 | 45.1 | 40.2 |
| Net fixed assets | 994.0 | 944.7 | 873.6 |
| Deferred charges/Goodwill | 163.2 | 157.4 | 71.8 |
| **Total** | 1196.0 | 1147.2 | 985.6 |

| **Liabilities & Equity** | 12 mos. Ending June 30, 2010 | As at Dec. 2009 | Dec. 2008 |
|---|---|---|---|
| Short-term debt | 0.0 | 0.0 | 0.0 |
| Debt due one yr. | 11.0 | 3.7 | 61.8 |
| A/P + accr'ds | 56.8 | 49.3 | 51.9 |
| **Current Liabilities** | 67.8 | 53.0 | 113.7 |
| Long-term debt | 540.7 | 528.6 | 418.0 |
| Secured debt | 43.3 | 43.7 | 47.5 |
| Capital lease obligations | 32.2 | 28.9 | 28.7 |
| Other l.t. liabilities | 100.7 | 96.0 | 12.6 |
| Shareholders' equity | 411.4 | 396.9 | 365.2 |
| **Total** | 1196.0 | 1147.2 | 985.6 |

| **Ratio Analysis** | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Liquidity Ratios** | June 30, 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
| Current ratio | 0.57 | 0.85 | 0.35 | 0.84 | 0.72 |
| Accumulated depreciation/gross fixed assets | 20.4% | 21.4% | 22.1% | 22.0% | 22.7% |
| Cash flow/adjusted debt (1) | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% |
| Cash flow/capital expenditures | 0.60 | 0.69 | 0.62 | 0.45 | 0.53 |
| Cash flow-dividends/capital expenditures | 0.49 | 0.56 | 0.49 | 0.37 | 0.43 |
| % debt in capital structure | 60.4% | 60.4% | 60.4% | 61.1% | 60.9% |
| % adjusted debt in capital structure (1) | 60.7% | 61.0% | 60.9% | 61.7% | 61.6% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| | | | | | |
| **Coverage Ratios** (1) | | | | | |
| EBIT interest coverage | 2.03 | 2.04 | 2.05 | 2.04 | 2.11 |
| EBITDA interest coverage | 3.09 | 3.06 | 3.09 | 3.04 | 3.09 |
| Fixed-charges coverage | 2.03 | 2.04 | 2.05 | 2.04 | 2.11 |
| Adjusted debt/EBITDA | 5.59 | 5.64 | 5.60 | 5.69 | 5.67 |
| | | | | | |
| **Earnings Quality/Operating Efficiency** | | | | | |
| Power purchases/revenues | 28.6% | 29.3% | 29.7% | 31.0% | 32.6% |
| EBIT margin | 30.1% | 29.9% | 29.4% | 28.5% | 27.6% |
| Net margin (before extras) | 15.1% | 14.8% | 14.2% | 13.7% | 12.8% |
| Return on avg. common equity (before extras) | 9.2% | 9.5% | 9.4% | 9.6% | 9.5% |
| Allowed ROE – mid-point | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |
| Direct customers/employee | 205 | 204 | 201 | 202 | 181 |
| Growth of customer base | 0.4% | 1.1% | 2.3% | 1.2% | 1.9% |
| Rate base ($ millions) | 949.0 | 867.7 | 822.8 | 747.2 | 676.0 |
| Growth in rate base | 9.4% | 5.5% | 10.1% | 10.5% | 14.3% |

(1) Adjusted for operating leases.

## SUMMARY OF OPERATING STATISTICS

| | 12 mos. Ending | For the 12-month period ended | | | | |
|---|---|---|---|---|---|---|
| **Generation** | June 30, 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 | Dec. 2005 |
| Hydro capacity (MW) | 223 | 223 | 223 | 223 | 235 | 214 |
| Gross energy generated (GWh) | 1,544 | 1,539 | 1,610 | 1,498 | 1,509 | 1,625 |
| Plus: purchases | 1,802 | 1,909 | 1,790 | 1,912 | 1,896 | 1,724 |
| Energy generated + purchased | 3,346 | 3,448 | 3,400 | 3,410 | 3,405 | 3,349 |
| Less: transmission losses + internal use | 277 | 291 | 313 | 320 | 365 | 378 |
| Total GWh sold | 3,069 | 3,157 | 3,087 | 3,090 | 3,040 | 2,971 |
| | | | | | | |
| Energy lost + used/energy gen. + purch. | 8.3% | 8.4% | 9.2% | 9.4% | 10.7% | 11.3% |

**FortisBC Inc.**

**Report Date:**
October 26, 2010

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Upgraded | Stable |
| Unsecured Debentures | A (low) | Upgraded | Stable |

## Rating History

| | Current | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|---|
| Secured Debentures | A (low) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | A (low) | BBB (high) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |

Note:
All figures are in Canadian dollars unless otherwise noted.

**Rating Report**
**Report Date:**
October 6, 2011

**Report Date:**
October 26, 2010

DBRS

*Insight beyond the rating.*

# FortisBC Inc.


**Analysts**
**Robert Filippazzo**
+1 416 597 7340
rfilippazzo@dbrs.com

**Yean (Kit) Kitnikone**
+1 416 597 7325
kkitnikone@dbrs.com


**The Company**
FortisBC Inc. (FortisBC) is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 megawatts) on the Kootenay River in south-central B.C. and FortisBC provides electricity services to approximately 161,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as in commercial real estate and hotel operations.

**Recent Actions**
**November 19, 2010**
Rates $100 million New Issue

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Confirmed | Stable |
| Unsecured Debentures | A (low) | Confirmed | Stable |

## Rating Rationale

DBRS has confirmed the ratings of FortisBC Inc.'s (FortisBC's or the Company's) Secured Debentures and Unsecured Debentures at A (low), with Stable trends. The rating confirmation reflects FortisBC's low business risk, stemming from the regulated nature of its operations and supportive regulatory environment; its integrated operations, which include a secure low-cost hydro-based power supply portfolio; its diversified customer base; its demonstrated ability to execute as planned; its stable credit metrics over the years despite the continued capital expenditure-driven free cash flow deficits; and its strong parental support from Fortis Inc. (Fortis, rated A (low), with a Stable trend); see separate DBRS rating report).

The regulatory environment remains stable and supportive, providing a strong cost-of-service/rate-of-return rate-setting methodology, with some performance-based rate (PBR)-setting attributes. The cost-of-service methodology allows for recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame.

In December 2010, FortisBC received approval by the British Columbia Utilities Commission (BCUC) for a 6.6% rate increase, effective January 1, 2011. The rate increase is inclusive of the 2011 Revenue Requirements negotiated settlement agreement and the 2011 Capital Expenditure Plan (CEP), as well as the 2011 allowed return on equity (ROE) of 9.90%. In addition, the BCUC also approved a refundable interim rate increase of 1.4% effective June 1, 2011, arising from an increase in 2011 power purchase expenses as a result of a refundable interim increase approved for British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated June 6, 2011). (Continued on page 2.)

## Rating Considerations

**Strengths**
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

**Challenges**
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Earnings and cash flow affected by lower ROEs

## Financial Information

| ($ millions) | 12 mos. Ending June 30, 2011 | For the 12-month period ended Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
|---|---|---|---|---|---|---|
| EBIT | 89.9 | 78.4 | 73.0 | 67.3 | 62.7 | 57.2 |
| EBIT interest coverage | 2.31 | 2.10 | 2.04 | 2.05 | 2.04 | 2.11 |
| EBITDA interest coverage | 3.41 | 3.21 | 3.06 | 3.09 | 3.04 | 3.09 |
| % total debt in the capital structure | 60.2% | 60.7% | 60.4% | 60.4% | 61.1% | 60.9% |
| Cash flow/total debt | 13.8% | 12.3% | 12.2% | 11.4% | 11.4% | 11.2% |
| Cash flow/capital expenditures (times) | 0.80 | 0.59 | 0.69 | 0.62 | 0.45 | 0.53 |
| Free cash flow | (56.5) | (72.3) | (55.3) | (45.6) | (73.3) | (67.4) |
| Approved ROE | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |

**FortisBC Inc.**

**Report Date:**
October 6, 2011

## Rating Rationale (Continued from page 1.)

FortisBC filed its 2012–2013 Revenue Requirements Application, along with the Company's Integrated System Plan (ISP), with the BCUC in June 2011, which resulted in a request for an interim 4.0% rate increase for electricity customers effective January 1, 2012, and a 6.9% increase effective January 1, 2013. The two-year Revenue Requirements is based on a cost-of-service/rate-of-return rate-setting methodology. The filing included the 2012–2013 CEP, which outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and deliver Demand-Side Management (DSM) programs to the Company's growing customer base.

The 2012–2013 CEP includes capital expenditures of $100.1 million and $123.2 million (net of customer contributions) and DSM expenditures of $5.8 million and $5.9 million for 2012 and 2013, respectively. The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term DSM Plan.

FortisBC's ROE of 9.90% is a result of a positive 2009 decision that also determined that the automatic-adjustment mechanism that was used to determine the ROE on an annual basis would no longer apply and the ROE as determined would apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. DBRS believes that while the ROE is favourable, uncertainty remains as to when and how ROE levels will be adjusted in the future.

FortisBC continues to invest in its significant capital program, which will be the greatest challenge for the Company over the medium term. The Company's elevated capital expenditure program, which has been ongoing for several years and is expected to be between $450 million and $500 million over the next five years, is projected to cause continuing free cash flow deficits over the medium term. The primary focus of this large capital program is to provide reliable service to a growing customer base and to ensure public and employee safety. The resulting free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent, Fortis, to maintain its current credit profile and capital structure at the regulatory-approved levels. Fortis is a large, integrated utility holding company that has the financial wherewithal to provide equity support as required in this context.

DBRS expects the key credit ratios to remain stable over the next few years before showing modest improvement as capital expenditures level off. Despite the continuing free cash flow deficits over the near to medium term, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. With its $160 million in bank credit facilities (including a $10 million demand overdraft facility), FortisBC's liquidity is considered sufficient to meet any short-term funding requirements.

## Rating Considerations Details

**Strengths**

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a return on its investments. The Company has operated under a PBR mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements. FortisBC's 2012–2013 Revenue Requirements application, filed in June 2011, is based on a cost-of-service/rate-of-return rate-setting methodology and does not include a continuation of the PBR mechanism.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River system, with a total generating capacity of 223 megawatts (MW), which provide about 45% of FortisBC's energy needs and 30% of its capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) among BC Hydro, FortisBC and other parties, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing from this portfolio the water-flow risk that is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licences and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts, including (a) a long-term take-or-pay contract with Brilliant Power Corporation (Brilliant, rated A (high), with a Stable trend; see separate DBRS rating report dated November 9, 2010). The contract runs until 2056 and supplies on average since 2007 low-cost power representing 27% of the Company's energy needs, and (b) a power purchase contract with BC Hydro. This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating a renewal of the contract. On average since 2007, approximately 95% of FortisBC's energy requirements were met through the combination of owned generation and these supply sources. The balance of supply was met through small power purchase contracts and spot market purchases.

Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (averaging approximately 5% of the Company's energy load requirements since 2007) are passed on to customers as well. The Company has made various types of advance purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2010, electricity sales to stable residential customers accounted for about 40% of total sales volume, while 23% of sales were to commercial customers and 29% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 8% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impact of an economic downturn.

**Challenges**

(1) FortisBC's financial profile continues to be affected by free cash flow deficits from its ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's capital expenditure program has been ongoing for several years and is expected to be approximately $450 million to $500 million (net of customer contributions) over the next five years. Internal cash flow generation (net of dividends) will continue to fund the majority of capital expenditures for the next few years. The remainder will be financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining a capital structure at the regulatory-approved 60% debt/40% equity level. The Company will need to seek some external debt financing during this stage of capital growth, which will likely keep key coverage ratios restrained during this period. Fortis is expected to provide equity support in order to maintain the Company's regulatory-approved capital structure.

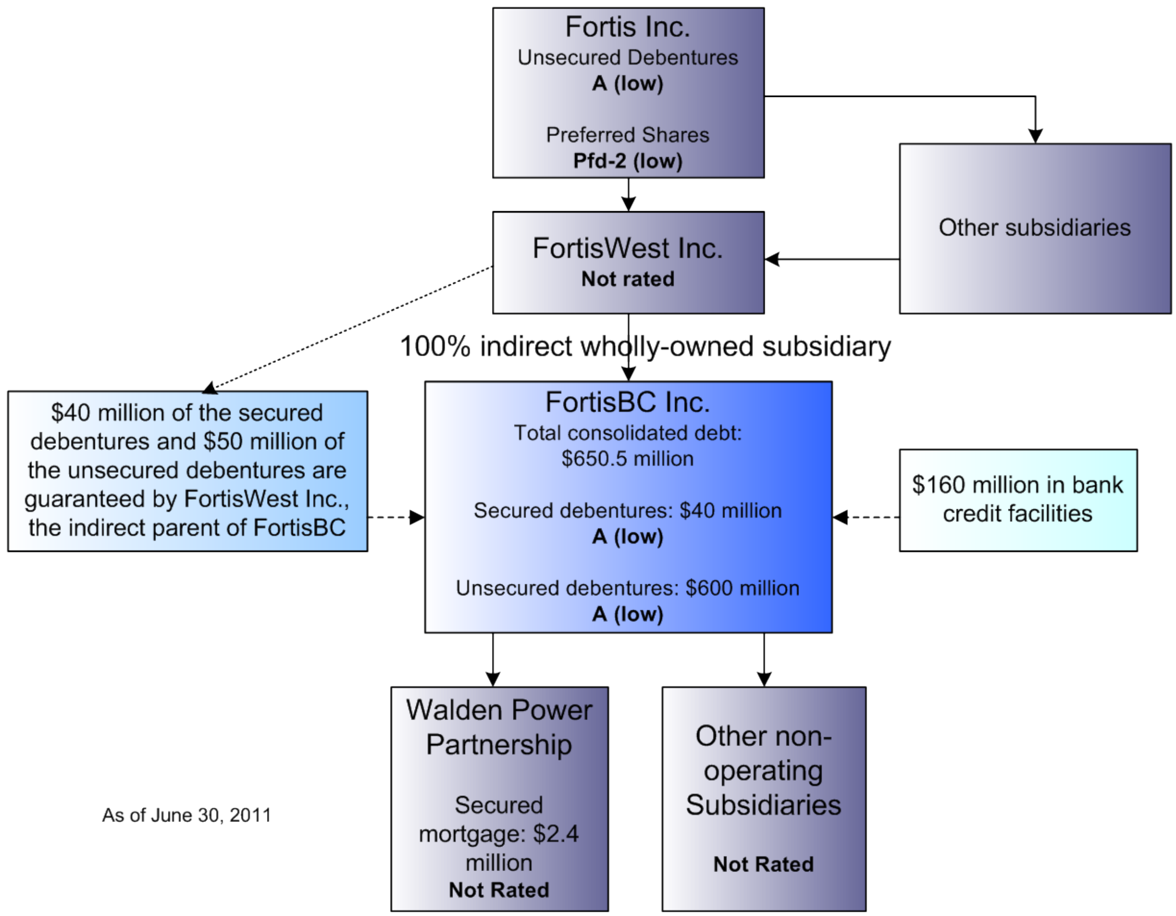
(2) The Company faces execution risk with respect to its large capital expenditure program over the next five years. The focus of the capital program will be on providing reliable service to a growing customer base, ensuring public and employee safety and completing projects on budget.

(3) The BCUC terminated the automatic-adjustment ROE formula and set FortisBC's approved level at 9.90% (effective January 1, 2010), after having been in the low 9% range and below since 2007. While FortisBC's ROE is now set at a benchmark level plus 40 basis points (bps), the absolute increase in the benchmark level (i.e., FortisBC Energy Inc.'s (FEI's) ROE, which rose to 9.50%) drove the increase in FortisBC's ROE to the 9.90% level. With the use of the automatic-adjustment formula having been terminated, there is uncertainty as to how ROE levels will be determined in the medium and longer term.

FortisBC Inc.

**Report Date:**
October 6, 2011

## Simplified Ownership/Debt Chart



FortisBC Inc.

**Report Date:**
October 6, 2011

## Earnings and Outlook

| ($ millions) | 12 mos. Ending June 30, 2011 | For the 12-month period ended Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 |
|---|---|---|---|---|---|
| Revenues | 272.4 | 256.9 | 244.1 | 229.2 | 219.7 |
| EBITDA | 133.3 | 120.1 | 110.1 | 101.5 | 93.8 |
| EBIT | 89.9 | 78.4 | 73.0 | 67.3 | 62.7 |
| Gross interest expense | 38.4 | 36.8 | 35.4 | 32.4 | 30.4 |
| Core net income | 47.7 | 41.8 | 36.2 | 32.7 | 30.1 |
| Net income (reported) | 47.7 | 41.8 | 36.2 | 32.7 | 30.1 |
| Return on average common equity | 10.8% | 10.5% | 9.5% | 9.4% | 9.6% |
| | | | | | |
| Approved Rate Base | 1,093.2 | 975.1 | 908.0 | 822.8 | 747.2 |
| Growth in Rate Base | 12.1% | 7.4% | 10.4% | 10.1% | 10.5% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Approved ROE | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% |

**Summary**

FortisBC has witnessed a continual improvement in EBITDA and EBIT, which can be primarily attributed to the Company's increasing rate base, higher ROEs and the terms of the PBR agreement.

More than 95% of FortisBC's operations are regulated, providing strong stability to earnings and cash flow. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the bulk of the Company's revenues. Electricity revenues increased for the 12 months ending June 30, 2011, as a direct result of rate increases approved by the BCUC, driven primarily by ongoing investment in infrastructure and higher cost of capital.

The increase in interest expense for the 12 months ending June 30, 2011, and year ending 2010 is primarily due to increased borrowings sourced to finance the capital expenditure program. Nevertheless, coverage ratios remain fairly stable as a result of the earnings growth.

The impact of power price volatility on earnings is limited as power procurement-related costs are passed on to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply, on average since 2007, approximately 95% of FortisBC's power load requirements are automatically passed on to customers. The remaining 5% has been procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed on to customers as well. The Company has made various types of advance market purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

**Outlook**

Going forward, FortisBC should benefit from a recovery of economic activity and overall consumption. DBRS continues to believe that the current 9.90% ROE and the growth in rate base related to the ongoing capital projects will have a positive impact on earnings going forward. The investment in capital assets is necessary to provide reliable service to a growing customer base and to ensure public and employee safety.

DBRS expects EBIT and net income to continue to grow over the medium term due to growth in rate base and the continuation of the 9.90% ROE.

FortisBC Inc.

**Report Date:**
October 6, 2011

## Financial Profile

| ($ millions) <br> **Cash Flow Statement** | 12 mos. Ending June 30, 2011 | For the 12-month period ended Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 |
|---|---|---|---|---|---|
| Core net income | 47.7 | 41.8 | 36.2 | 32.7 | 30.1 |
| Depreciation and amortization | 43.8 | 42.0 | 37.5 | 34.2 | 31.1 |
| Other non-cash adjustments | 5.5 | 0.7 | 2.0 | (1.8) | (0.1) |
| **Cash Flow From Operations** | 97.0 | 84.5 | 75.7 | 65.1 | 61.0 |
| Common dividends | (16.0) | (15.0) | (14.5) | (13.4) | (11.8) |
| Capital expenditures | (120.5) | (142.8) | (110.2) | (105.3) | (134.2) |
| **Free Cash Flow Before W/C Changes** | (39.5) | (73.3) | (49.0) | (53.6) | (85.0) |
| Net changes in working capital | (17.0) | 1.1 | (6.3) | 8.1 | 11.7 |
| **Net Free Cash Flow** | (56.5) | (72.3) | (55.3) | (45.6) | (73.3) |
| Other investing activities | (6.9) | (4.9) | (2.8) | (2.2) | (0.1) |
| Other adjustments | (5.6) | 6.0 | (0.6) | 0.3 | (0.6) |
| **Amount to be Financed** | (68.9) | (71.2) | (58.7) | (47.4) | (74.0) |
| Net debt financing | 59.5 | 62.1 | 49.7 | 32.5 | 60.2 |
| Net equity financing | 10.0 | 10.0 | 10.0 | 15.0 | 15.0 |
| Other financing | (0.9) | (0.9) | (1.0) | (0.0) | (1.2) |
| **Net Change in Cash** | (0.3) | (0.0) | (0.0) | 0.0 | (0.0) |
| | | | | | |
| % debt in capital structure | 60.2% | 60.7% | 60.4% | 60.4% | 61.1% |
| EBIT interest coverage (times) | 2.31 | 2.10 | 2.04 | 2.05 | 2.04 |
| Cash flow/total debt | 13.8% | 12.3% | 12.2% | 11.4% | 11.4% |
| Total debt to EBITDA (times) | 5.27 | 5.71 | 5.64 | 5.60 | 5.69 |
| Dividend payout ratio | 33.5% | 35.9% | 40.0% | 41.0% | 39.3% |

**Summary**

Cash flow from operations has witnessed an increase over time as a result of higher net income, which can be attributed to increased revenues as the Company added capital assets to its rate base. Depreciation and amortization rates have increased over the years and particularly during 2010, largely the result of changes to a growing depreciable asset base as capital assets were added to rate base.

DBRS notes that although FortisBC maintains strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits, which are financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining capital structure at the regulatory-approved 60% debt/40% equity.

FortisBC has witnessed an overall improvement in credit metrics in 2010 and during the last 12 months (LTM) ending June 30, 2011. DBRS believes that the Company will continue to maintain a reasonable financial profile, reflecting an improving balance sheet and credit metrics for the rating.

**Outlook**

Free cash flow deficits are expected to persist as a result of the ongoing capital expenditure program. However, improving revenues and net income as a result of these capital expenditures increasing the rate base should continue to lead to an increase in cash flow, which will cause a modest decline in cash flow deficits. Annual capital expenditures are expected to remain high, with approximately $450 million to $500 million in projects planned over the next five years. DBRS expects cash flow deficits will be financed with incremental debt and equity support from Fortis. DBRS expects cash flow from operations to be largely adequate to fund future capital expenditures. Therefore, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat to modestly improving during this elevated capital program period as increased debt levels are offset by higher earnings on a growing rate base.

## Long-Term Debt Maturities and Liquidity

Debt Chart ($millions)

| | | June 30/11 |
|---|---|---|
| Secured Debentures | | |
| *Guaranteed by FortisWest Inc.* | | |
| Oct. '12 | 9.65% | 15.0 |
| Aug. '23 | 8.80% | 25.0 |
| WPP Mortgage | | |
| Oct. '13 | 9.44% | 2.4 |
| | | 42.4 |
| Unsecured Debentures | | |
| *Guaranteed by FortisWest Inc.* | | |
| Feb. '16 | 8.77% | 25.0 |
| Dec. '21 | 7.81% | 25.0 |
| *No Guarantee* | | |
| Nov. '14 | 5.48% | 140.0 |
| Nov. '35 | 5.60% | 100.0 |
| July '47 | 5.90% | 105.0 |
| MTN June '39 | 6.10% | 105.0 |
| MTN Nov '50 | 5.00% | 100.0 |
| | | 600.0 |
| Bank Credit Facilities | | |
| Operating credit facilties | | 7.0 |
| Overdraft facility | | 1.1 |
| | | 8.1 |
| Total Debt | | 650.5 |
| Less current portion | | 2.1 |
| Long-Term Debt | | 648.4 |

as at June 30, 2011

| Maturity Schedule ($MM) | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 2.1 | 15.9 | 7.5 | 140.0 | 0.0 | 485.0 | 650.5 |

FortisBC had $650.5 million of total consolidated debt outstanding at June 30, 2011, including $600 million of unsecured debentures, $42.4 million of secured debt (including the Walden Power Partnership (WPP) mortgage) and $8.1 million of bank credit facilities (including the $1.1 million in overdrafts).

The secured debt is expected to continue to account for a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series F and Series G), totaling $40 million, and the unsecured debentures (Series H and Series I), totaling $50 million, are guaranteed by FortisWest Inc. (FW). FW is a direct wholly owned subsidiary of Fortis, whose assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding when Fortis purchased the Company.

The debt profile as of June 30, 2011, is as follows:

- $40 million in secured debentures, Series F and Series G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company. These debentures mature in 2012 and 2023, respectively

- $50 million in unsecured debentures, Series H and Series I, also guaranteed by FW and maturing in 2016 and 2021, respectively.
- An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
- $205 million in unsecured medium-term note debentures, Series 1 and Series 2, that mature in June 2039 and November 2050, respectively.
- A $2.4 million mortgage on the Walden power plant in British Columbia, owned and operated by WPP, which is secured by a pledge by FortisBC of its interest in WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

FortisBC's bank credit facilities amended in April 2011 and consist of the following:
- A $100 million three-year revolving unsecured operating credit facility, maturing May 7, 2014.
- An additional $50 million 364-day revolving unsecured operating credit facility, maturing on May 3, 2012. This facility may be extended for another 364 days or, if not extended, termed out for a six-month period.
- A $10 million demand overdraft facility.

As of June 30, 2011, $7.0 million was utilized against the $150 million operating credit facilities (December 31, 2010 – zero) and $1.1 million was drawn on the overdraft facility.

Certain of the Company's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 70% of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceed thresholds based on the cumulative net earnings of the Company.

**Outlook**
FortisBC's $160 million in bank credit facilities (including $10 million in demand overdraft facilities) should provide sufficient liquidity to meet any short-term funding requirements. As at June 30, 2011, $151.9 million was available under the bank credit facilities. The debt repayment schedule is modest; however, the Company has $140 million due in 2014. DBRS expects FortisBC to refinance its maturing debt given its stable credit profile and cash flows generated from its low-risk operations. Furthermore, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

## Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 161,000 direct and indirect customers, including wholesale customers such as the cities of Kelowna and Nelson.

Approximately 63% of its power is sold to relatively stable residential and commercial customers, 8% to industrial customers and 29% to wholesale customers, which resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:
- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the CPA among BC Hydro, FortisBC and other parties, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012.
- The power purchase contract with the Brilliant hydroelectric plant, which expires in 2056, supplies on average since 2007, approximately 27% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant.
- The long-term, firm power purchase contract with BC Hydro, expiring in 2013, which provided, on average since 2007, 23% of the Company's energy needs.

- A number of small purchase power contracts with independent power producers collectively provide approximately 1% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

FortisBC also has a limited amount of non-regulated operations, principally made up of WPP, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

## Regulation

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure and the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. For the period of 2006 through 2011, rates were based on a cost-of-service/rate-of-return methodology, with some PBR-setting attributes as described below. FortisBC's 2012–2013 Revenue Requirements application, filed in June 2011, is based on a cost-of-service/rate-of-return rate-setting methodology and does not include a continuation of the PBR mechanism.

The significant terms of the PBR agreement negotiated in 2006 are as follows:

- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (i.e., the consumer price index (CPI) for British Columbia) minus a productivity improvement factor (PIF) of 2% in 2007, 2% in 2008 and if applicable, 3% in 2009.
- Annual capitalized overhead will be set at 20% of the BCUC-approved gross operating and maintenance expense.
- Other components of revenue requirements will be forecast annually.
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances that flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally among customers and shareholders. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review and disposition during the next rate-setting process. The Company's portion of the incentive is subject to the Company meeting certain performance standards and BCUC approval.

The ROE for FortisBC was set at 9.90% in 2010 and remains unchanged in 2011.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formulae incorporating customer growth and inflation (i.e., CPI for British Columbia) minus a PIF of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF, which effectively caps the CPI at 3%.

In December 2010, FortisBC received approval by the BCUC for a 6.6% rate increase effective January 1, 2011. The rate increase is inclusive of the 2011 Revenue Requirements negotiated settlement agreement and 2011 CEP, as well as the 2011 allowed ROE of 9.90%. In addition, the BCUC also approved a refundable interim rate increase of 1.4%, effective June 1, 2011, arising from an increase in 2011 power purchase expense following a refundable interim increase approved for BC Hydro.

FortisBC filed its 2012–2013 Revenue Requirements application, along with the Company's ISP, with the BCUC in June 2011, which resulted in a request for an interim 4.0% rate increase for electricity customers effective January 1, 2012, and a 6.9% increase effective January 1, 2013. The two-year Revenue Requirements is based on a cost-of-service/rate-of-return rate-setting methodology. The filing included the 2012–2013 CEP, which outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and deliver DSM programs to the Company's growing customer base.

The 2012–2013 CEP includes capital expenditures of $100.1 million and $123.2 million (net of customer contributions) and DSM expenditures of $5.8 million and $5.9 million for 2012 and 2013, respectively. The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term DSM Plan.

**FortisBC Inc.**

**Report Date:**
October 6, 2011

FortisBC's ROE of 9.90% is the result of a positive 2009 decision that also determined that the automatic-adjustment mechanism that was used to determine the ROE on an annual basis would no longer apply and the ROE as determined would apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. DBRS believes that while the ROE is favourable, uncertainty remains as to when and how ROE levels will be adjusted in the future.

As at December 31, 2010, FortisBC had total assets of $1,271.4 million and approved rate-base assets of $975.1 million. Approved rate-base assets in the 2011 Revenue Requirements application are $1,093.2 million.

**FortisBC Inc.**

**Report Date:**
October 6, 2011

**FortisBC Inc.**

| **Balance Sheet** ($ millions) | 12 mos. Ending June 30, 2011 | As at Dec. 2010 | Dec. 2009 |
|---|---|---|---|
| **Assets** | | | |
| Cash + equivalents | 0.0 | 0.0 | 0.0 |
| Accounts receivable/unbilled revenue | 37.4 | 45.8 | 41.1 |
| Inventories | 0.6 | 0.5 | 0.5 |
| Other | 10.8 | 3.0 | 3.5 |
| **Current Assets** | 48.9 | 49.3 | 45.1 |
| Net fixed assets | 1073.8 | 1049.0 | 944.7 |
| Deferred charges/Goodwill | 175.7 | 173.2 | 157.4 |
| **Total** | 1298.4 | 1271.4 | 1147.2 |

| **Liabilities & Equity** | 12 mos. Ending June 30, 2011 | As at Dec. 2010 | Dec. 2009 |
|---|---|---|---|
| Short-term debt | 0.0 | 0.0 | 0.0 |
| Debt due one yr. | 11.8 | 2.0 | 3.7 |
| A/P + accr'ds | 46.6 | 60.5 | 49.3 |
| **Current Liabilities** | 58.4 | 62.5 | 53.0 |
| Long-term debt | 600.2 | 593.0 | 528.6 |
| Secured debt | 42.4 | 42.9 | 43.7 |
| Capital lease obligations | 32.2 | 31.9 | 28.9 |
| Other l.t. liabilities | 112.1 | 107.5 | 96.0 |
| Shareholders' equity | 453.1 | 433.7 | 396.9 |
| **Total** | 1298.4 | 1271.4 | 1147.2 |

| **Ratio Analysis** | 12 mos. Ending | For the 12-month period ended | | | |
|---|---|---|---|---|---|
| **Liquidity Ratios** | June 30, 2011 | Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 |
| Current ratio | 0.84 | 0.79 | 0.85 | 0.35 | 0.84 |
| Accumulated depreciation/gross fixed assets | 20.6% | 20.6% | 21.4% | 22.1% | 22.0% |
| Cash flow/adjusted debt (1) | 13.8% | 12.3% | 12.2% | 11.4% | 11.4% |
| Cash flow/capital expenditures | 0.80 | 0.59 | 0.69 | 0.62 | 0.45 |
| Cash flow-dividends/capital expenditures | 0.67 | 0.49 | 0.56 | 0.49 | 0.37 |
| % debt in capital structure | 60.2% | 60.7% | 60.4% | 60.4% | 61.1% |
| % adjusted debt in capital structure (1) | 60.8% | 61.2% | 61.0% | 60.9% | 61.7% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| **Coverage Ratios** (1) | | | | | |
| EBIT interest coverage | 2.31 | 2.10 | 2.04 | 2.05 | 2.04 |
| EBITDA interest coverage | 3.41 | 3.21 | 3.06 | 3.09 | 3.04 |
| Fixed-charges coverage | 2.31 | 2.10 | 2.04 | 2.05 | 2.04 |
| Adjusted debt/EBITDA | 5.27 | 5.71 | 5.64 | 5.60 | 5.69 |
| **Earnings Quality/Operating Efficiency** | | | | | |
| Power purchases/revenues | 26.9% | 28.4% | 29.3% | 29.7% | 31.0% |
| EBIT margin | 33.0% | 30.5% | 29.9% | 29.4% | 28.5% |
| Net margin (before extras) | 17.5% | 16.3% | 14.8% | 14.2% | 13.7% |
| Return on avg. common equity (before extras) | 10.8% | 10.5% | 9.5% | 9.4% | 9.6% |
| Allowed ROE – mid-point | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% |
| Direct customers/employee | 211 | 210 | 205 | 201 | 202 |
| Growth of customer base | 0.8% | 1.3% | 1.1% | 2.3% | 1.2% |
| Rate base ($ millions) | 1,093.2 | 975.1 | 908.0 | 822.8 | 747.2 |
| Growth in rate base | 12.1% | 7.4% | 10.4% | 10.1% | 10.5% |

(1) Adjusted for operating leases.

## SUMMARY OF OPERATING STATISTICS

| | 12 mos. Ending | For the 12-mo For the 12-month period ended | | | | |
|---|---|---|---|---|---|---|
| **Generation** | June 30, 2011 | Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
| Hydro capacity (MW) | 223 | 223 | 222 | 223 | 223 | 235 |
| Gross energy generated (GWh) | 1,544 | 1,530 | 1,586 | 1,610 | 1,498 | 1,509 |
| Plus: purchases | 1,880 | 1,796 | 1,893 | 1,790 | 1,912 | 1,896 |
| Energy generated + purchased | 3,424 | 3,326 | 3,479 | 3,400 | 3,410 | 3,405 |
| Less: transmission losses + internal use | 281 | 280 | 322 | 313 | 320 | 365 |
| Total GWh sold | 3,143 | 3,046 | 3,157 | 3,087 | 3,090 | 3,040 |

FortisBC Inc.

**Report Date:**
October 6, 2011

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Confirmed | Stable |
| Unsecured Debentures | A (low) | Confirmed | Stable |

## Rating History

| | Current | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|
| Secured Debentures | A (low) | A (low) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | A (low) | A (low) | BBB (high) | BBB (high) | BBB (high) | BBB (high) |

## Related Research

- DBRS Rates FortisBC Issue of $100 Million 5.00% Medium-Term Notes, Series 2, at A (low), November 19, 2010.

Note:
All figures are in Canadian dollars unless otherwise noted.

# FortisBC Inc.

**Analysts**
**Eric Eng, MBA**
+1 416 597 7578
eeng@dbrs.com

**James Jung, CFA, FRM, CMA**
+1 416 597 7577
jjung@dbrs.com

**Adeola Adebayo**
+1 416 597 7421
aadebayo@dbrs.com

**The Company**
FortisBC Inc. is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 megawatts) on the Kootenay River in south-central B.C. and FortisBC provides electricity services to approximately162,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as in commercial real estate and hotel operations.

**Recent Actions**
**October 6, 2011**
Confirmed

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Confirmed | Stable |
| Unsecured Debentures | A (low) | Confirmed | Stable |

## Rating Update

DBRS has confirmed the ratings of FortisBC Inc.'s (FortisBC or the Company) Secured Debentures and Unsecured Debentures at A (low), with Stable trends. The Unsecured Debentures have the same rating as the Secured Debentures, reflecting that (1) the amount outstanding of Secured Debentures is minimal (6% of total debt) and (2) FortisBC does not intend to issue additional Secured Debentures in the future. The rating confirmation reflects FortisBC's strong business risk profile, solid financial profile and a reasonable regulatory framework.

FortisBC is one of a few investor-owned Canadian utilities that generate virtually all earnings from integrated, regulated operations (transmission, distribution and generation assets). Risks associated with the electricity generating assets (which tend to be higher than those of transmission and distribution) are manageable given that the hydro facilities are low cost and emission free, with no exposure to hydrogeology risk as a result of a long-term contract under the Canal Plant Agreement (CPA) (see Regulation). The Company's business risk profile benefits from a reasonable regulatory environment (cost-of-service (COS) methodology and performance-based rate (PBR) setting until 2011) that provides a return on equity (ROE) at 9.9% on a 40% deemed equity component. The COS allows for recovery of prudently forecast power purchase costs and capital expenditures within a reasonable time frame while the PBR provides an ROE sharing mechanism whereby variances in actual financial performance are shared equally between customers and the shareholders (see Regulation).

FortisBC continued to generate significant negative cash flow due to high capital investments to accommodate customer growth. However, the Company financed the deficits with a balanced mix of debt and equity injection from its parent, Fortis Inc. (rated A (low)). As a result, the Company's credit metrics remained solid, with its debt-to-capital ratio at 60% (in line with the regulatory capital structure) and interest coverage and cash flow ratios commensurate with the current rating category. Cash flow deficits are expected to continue due to the ongoing high capital expenditures (estimated $120 million per year over the next two years). However, DBRS expects the parent to continue to provide financial support in a timely manner to maintain the Company's credit metrics within DBRS's A (low) rating parameters.

## Rating Considerations

| Strengths | Challenges |
|---|---|
| (1) Reasonable regulatory environment | (1) Large capital expenditure program |
| (2) Vertically integrated utility | (2) Execution risk of capital projects |
| (3) Secured and reliable supply contracts | (3) Parent support required |
| (4) Diversified customer base/strong rate base growth | (4) Potential lower ROE |

## Financial Information

| | For the year end ended December 31 | | | | | |
|---|---|---|---|---|---|---|
| ($ millions) | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 |
| EBIT | 96.3 | 78.4 | 73.0 | 67.3 | 62.7 | 57.2 |
| EBIT interest coverage | 2.40 | 2.10 | 2.04 | 2.05 | 2.04 | 2.11 |
| EBITDA interest coverage | 3.52 | 3.21 | 3.06 | 3.09 | 3.04 | 3.09 |
| % total debt in the capital structure | 59.4% | 60.5% | 60.4% | 60.4% | 61.1% | 60.9% |
| Cash flow/total debt | 13.3% | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% |
| Cash flow/capital expenditures (times) | 0.95 | 0.59 | 0.69 | 0.62 | 0.45 | 0.53 |
| Free cash flow | (12.9) | (72.3) | (55.3) | (45.6) | (73.3) | (67.4) |
| Approved ROE | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |

## Rating Considerations Details

**Strengths**

(1) **Reasonable regulatory environment:** FortisBC has a strong business risk profile as virtually all of its operations are in the regulated utility business, which operates in a stable, reasonable regulatory environment that allows it to recover its prudently incurred operating costs and earn a reasonable return on its investments.

(2) **Integrated utility with transmission, distribution and hydro generation assets:** FortisBC is a vertically integrated regulated utility, which owns transmission, distribution and generation assets. The Company's four generation plants, with 223 megawatts (MW) of capacity on the Kootenay River, are insulated from hydrology risk (see Regulation). This provides stability to power supply costs.

(3) **Secured and reliable power contracts:** FortisBC benefits from having secure electricity supply contracts, including (a) a long-term take-or-pay contract with Brilliant Power Corporation (Brilliant; rated A (high)), which runs until 2056 and (b) a power purchase contract with BC Hydro (BC Hydro PPA). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. Approximately 90% of FortisBC's energy requirements were met through the combination of owned generation and these supply sources. The balance of supply was met through small power purchase contracts and spot market purchases.

(4) **Diverse customer base and strong rate base asset growth:** The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to earnings. DBRS estimates that, in 2011, approximately 40% of volume sales were sold to stable residential customers, 23% to commercial customers and 29% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 8% of sales were to low-margin, economically sensitive industrial customers. This mitigates the negative impact of an economic downturn. In addition, the Company's franchise area has experienced strong rate base asset growth, averaging 10% per year over the past five years.

**Challenges**

(1) **Large capex program:** FortisBC has a large capital expenditure program ($111 million for 2012 and $133 million for 2013 – before customer contributions), which requires external financing. As a result, the Company is expected to generate negative free cash flow for the foreseeable future.

(2) **Execution risk of capital projects:** The Company faces execution risk with respect to its large capital expenditure program over the next few years. The focus of the capital program will be on providing reliable service to a growing customer base. Substantial cost overruns due to lengthy delays may not be fully recovered.

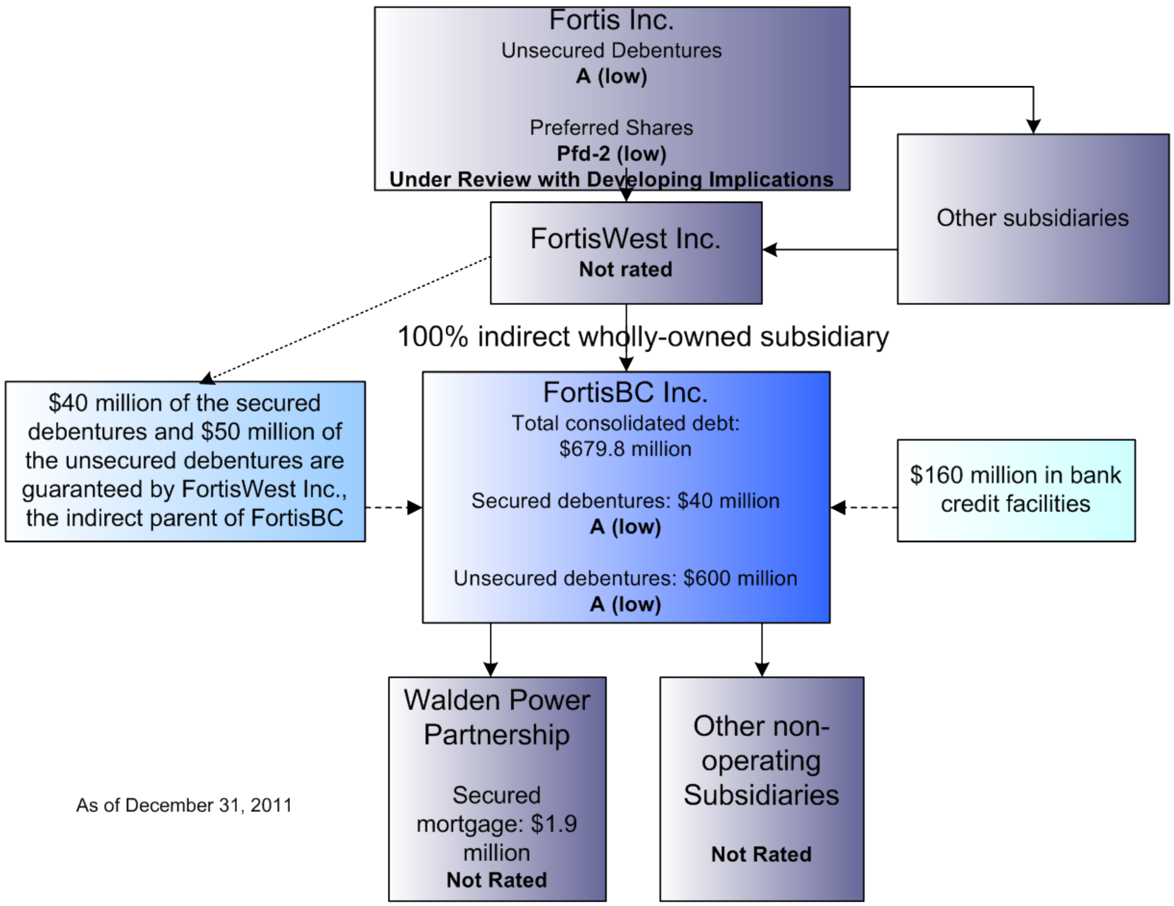
(3) **Parent support**: The Company is expected to require financing support from the parent to undertake its capital expenditure program. DBRS expects the parent to continue to support FortisBC with equity injection to maintain the Company capital structure in line with the regulatory capital structure.

(4) **Potential lower ROE:** The BCUC currently intends to review (1) setting an appropriate cost of capital for a benchmark low risk utility; (2) establishing an ROE automatic adjustment mechanism; and (3) establishing a deemed capital structure and deemed cost of capital for those utilities without third-party debt. This review may affect the Company's future ROE and deemed equity.

**FortisBC Inc.**

**Report Date:**
February 22, 2012

## Simplified Ownership/Debt Chart




**Note:** The total consolidated debt of FortisBC included capital leases of approximately $26 million.

## Regulation

**Overview:** DBRS views the regulatory framework in British Columbia as reasonable, as it allows FortisBC to earn a reasonable return on their capital investment and to recover prudently incurred operating costs. In addition, the Company has limited exposure to power purchase cost volatility for the period from 2006 to 2011 since variances between actual and forecast power costs are included in the ROE sharing mechanism and shared equally between customers and the shareholders.

***The period of 2006 through 2011***: Rates were based on a COS methodology, with some PBR setting described below:

- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (i.e., the consumer price index (CPI) for British Columbia) minus a productivity improvement factor (PIF)).
- The PIF was 2% in 2007, 2% in 2008, 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess would be added to the PIF, which effectively capped the CPI at 3%.
- Annual capitalized overhead was set at 20% of the BCUC-approved gross operating and maintenance expense, with other components of revenue requirements forecasted annually.
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances that flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally among customers and shareholders.
- If the variances are in excess of the 2% collar, the excess will be placed in a deferral account for regulatory review and disposition during the next rate-setting process.
- The ROE was set at 9.90% in 2010 and remained unchanged in 2011.

***2012-2013 Revenue Requirements Application (RRA), 2012-2013 capital expenditure plan (CEP) and the Integrated System Plan (ISP):***

- In June 2011, the Company file an RRA, which included the CEP and the ISP with the BCUC requesting the following:
  (1) An interim 4.0% rate increase effective January 2012;
  (2) A 6.9% rate increase effective January 1, 2013;
  (3) ROE for 2012 and 2013 of 9.9% (unchanged from 2010 and 2011);
  (4) Deemed equity of 40% (unchanged from 2010 and 2011);
  (5) Flow-through treatments for variances from the forecast used to set rates for electricity revenue, power purchase costs and certain other costs.
- In November 2011, the Company amended the RRA to include updated financial forecast and reduced a requested rate increase from 4.0% to 1.5% for 2012 and from 6.9% to 6.5% for 2013.
- The BCUC issued an order at the end of November 2011 ordering an oral hearing on the Company's RRA in March 2012 and approving a 1.5% increase in the interim rate effective January 1, 2012.

***Generic Cost of Capital Proceeding:***

- The BCUC currently intends to review (1) setting appropriate costs of capital for a benchmark low-risk utility; (2) establishing an ROE automatic adjustment mechanism; and (3) establishing a deemed capital structure and deemed cost of capital for those utilities without third-party debt.
- This review may affect the Company's future ROE and deemed equity.

***The Canal Plant Agreement (CPA):***

- CPA is an agreement among BC Hydro, FortisBC and three other parties. The CPA governs 1,565 MW of capacity of all five parties (including 223 MW of capacity owned by FortisBC).
- Under the CPA, BC Hydro determines the output of each plant and takes all of the power generated by the plants. BC Hydro is then contractually obligated to deliver a fixed amount of power to FortisBC regardless of its actual output, thus insulating FortisBC from hydrology risk.
- The CPA will remain in force until terminated by any of the parties by giving no less than five years' notice at anytime on or after December 31, 2030.

FortisBC Inc.

Report Date:
February 22, 2012

## Earnings and Outlook

| ($ millions) | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|
| | For the year ended December 31 | | | | | |
| Revenues | 283.9 | 256.9 | 244.1 | 229.2 | 219.7 | 207.6 |
| EBITDA | 141.6 | 120.1 | 110.1 | 101.5 | 93.8 | 84.1 |
| EBIT | 96.3 | 78.4 | 73.0 | 67.3 | 62.7 | 57.2 |
| Gross interest expense | 39.8 | 36.8 | 35.4 | 32.4 | 30.4 | 26.7 |
| Core net income | 47.5 | 41.8 | 36.2 | 32.7 | 30.1 | 26.5 |
| Net income (reported) | 47.5 | 41.8 | 36.2 | 32.7 | 30.1 | 26.5 |
| Return on common equity | 10.6% | 10.1% | 9.5% | 9.4% | 9.6% | 9.5% |
| | | | | | | |
| Approved rate base (1) | 1,093.2 | 975.1 | 908.0 | 822.8 | 747.2 | 676.0 |
| % Growth in rate base | 12.1% | 7.4% | 10.4% | 10.1% | 10.5% | 14.3% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Approved ROE | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |

(1) Rate base in 2011 was mid-year.

### Summary

- Earnings have benefited from strong growth in the rate base (which includes transmission, distributions and hydroelectric power generation assets) over the past five years as a result of the capital program to improve reliability and to accommodate customer growth.
- Higher earnings in 2011 compared with 2010 largely reflected a 6.9% increase in rates and ROE sharing.
- Power purchase price volatility has a limited impact on earnings due to the ROE sharing mechanism (see Regulation).

### Outlook

- FortisBC is expected to experience moderate earnings growth in 2012 and 2013 as the Company's rate base is expected to increase further, reflecting higher capital expenditures on system reliability and accommodation for customer growth ($111 million expected in 2012 and $133 million expected in 2013).
- The BCUC is reviewing ROE and cost of capital for utilities in the province. This could affect the Company's current deemed capital structure and allowed ROE. However, DBRS does not expect any material impact on earnings as a result of the BCUC's review.

# Financial Profile

| ($ millions) | For the year ended December 31 | | | | | |
|---|---|---|---|---|---|---|
| **Cash Flow Statement** | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 |
| Core net income | 47.5 | 41.8 | 36.2 | 32.7 | 30.1 | 26.5 |
| Depreciation and amortization | 45.7 | 42.0 | 37.5 | 34.2 | 31.1 | 26.9 |
| Other non-cash adjustments | (1.1) | 0.7 | 2.0 | (1.8) | (0.1) | (0.1) |
| **Cash Flow From Operations** | 92.1 | 84.5 | 75.7 | 65.1 | 61.0 | 53.3 |
| Common dividends | (16.0) | (15.0) | (14.5) | (13.4) | (11.8) | (10.2) |
| Capital expenditures | (96.7) | (142.8) | (110.2) | (105.3) | (134.2) | (101.1) |
| **Free Cash Flow Before W/C Changes** | (20.6) | (73.3) | (49.0) | (53.6) | (85.0) | (58.0) |
| Net changes in working capital | 7.7 | 1.1 | (6.3) | 8.1 | 11.7 | (9.4) |
| **Net Free Cash Flow** | (12.9) | (72.3) | (55.3) | (45.6) | (73.3) | (67.4) |
| Other investing activities | 7.2 | (4.9) | (2.8) | (2.2) | (0.1) | (2.8) |
| Other adjustments | (9.7) | 6.0 | (0.6) | 0.3 | (0.6) | 2.8 |
| **Amount to be Financed** | (15.4) | (71.2) | (58.7) | (47.4) | (74.0) | (67.4) |
| Net debt financing | 15.4 | 62.1 | 49.7 | 32.5 | 60.2 | 40.9 |
| Net equity financing | 0.0 | 10.0 | 10.0 | 15.0 | 15.0 | 20.0 |
| Other financing | 0.0 | (0.9) | (1.0) | (0.0) | (1.2) | 0.0 |
| **Net Change in Cash** | (0.0) | (0.0) | (0.0) | 0.0 | (0.0) | (6.5) |
| | | | | | | |
| % debt in capital structure | 59.4% | 60.5% | 60.4% | 60.4% | 61.1% | 60.9% |
| EBIT interest coverage (times) | 2.40 | 2.10 | 2.04 | 2.05 | 2.04 | 2.11 |
| Cash flow/total debt | 13.3% | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% |
| Total debt/EBITDA (times) | 4.89 | 5.66 | 5.64 | 5.60 | 5.69 | 5.67 |
| Dividend payout ratio | 33.7% | 35.9% | 40.0% | 41.0% | 39.3% | 38.5% |

## Summary

- Strong and persistent operating cash flow growth reflected higher earnings and higher depreciation due to the Company's growing rate base.
- Despite strong cash flow from operations, the Company has generated negative free cash flows over the past five years, largely reflecting high capital expenditures that were significantly higher than depreciation.
- Large capital expenditures reflected the Company's ongoing capital projects to address system reliability and customer growth.
- Dividend payout ratio was moderate between 33% and 41%.
- The Company has financed its free cash flow deficits with a balanced mix of debt and equity and has maintained its debt-to-capital ratio at approximately 60%, which was in line with the regulatory capital structure.
- As a result, the Company has maintained a solid financial profile, with all credit metrics being commensurate with the current rating.

## Outlook

- Free cash flow deficits are expected to persist as a result of the ongoing capital expenditure program. The Company estimates its capital expenditures for 2012 and 2013 at $111 million and $133 million (estimate, before customer contributions), respectively.
- DBRS expects cash flow deficits to be financed with incremental debt and equity support from Fortis Inc. to maintain the balance sheet leverage in line with the regulatory capital structure (40% equity/60% debt).
- Key credit ratios are expected to remain stable as higher debt levels will be supported by higher expected earnings and cash flow levels from a larger rate base.

**FortisBC Inc.**

**Report Date:**
February 22, 2012

## Liquidity and Debt Profile

### Liquidity

| **Credit facilities (Dec. 31, 2011)** | Committed | Available | Maturity |
|---|---|---|---|
| ($ millions) | | | |
| Facility A, revolving | 100 | | May 2014 |
| Facility B, 364-dayrevolving | 50 | | Mar 2012 |
| Operating facilities | 150 | 141.0 | |
| Overdraft demand facility (unsecured) | 10 | 1.5 | |
| **Total** | **160** | **142.5** | |

- The Company's liquidity position remained moderate with $142.5 million in available credit facilities at the end of 2011.
- DBRS believes these facilities are sufficient to fund the Company's ongoing operational and capital requirements.
- Two years prior to the expiry of Facility A, the Company may request an extension of a further 364 days, and if the request is not granted, all outstanding debt under Facility A will become due on the maturity date.
- The Company may also request an extension of Facility B for another 364 days, and if the request is not granted, Facility B will be converted into non-revolving term and will mature six months from that date.

### Long-Term Debt

| **Long-term debt** | Dec. 31 | Dec. 31 |
|---|---|---|
| ($ millions) | 2011 | 2010 |
| Secured Debentures | 41.9 | 42.9 |
| Unsecured Debentures | 600.0 | 600.0 |
| Operating facilities | 9.0 | 0.0 |
| Overdraft facility | 8.5 | 1.1 |
| **Total debt** | **659.4** | **644.0** |
| Less: Current portion of debt | 24.5 | 2.0 |
| Less: Deferred financing costs | 5.6 | 6.0 |
| **Total long-term debt** | **629.3** | **635.9** |

- DBRS rates Secured Debentures the same rating of A (low) as the Unsecured Debentures, reflecting that (1) the amount outstanding of Secured Debentures is immaterial and (2) the Company has no intention of issuing Secured Debentures in the future.
- Should the Company issue Secured Debentures in the future, the rating of Unsecured Debentures could be affected.

### Debt Maturity

As at December 31, 2011

| Maturity Schedule ($ million) | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | 24.5 | 0.9 | 149.0 | 0.0 | 25.0 | 460.0 | 659.4 |
| Capital leases | 0.4 | 3.2 | 3.3 | 3.2 | 3.3 | 12.5 | 25.9 |
| Deferred financing charge and other | | | | | | | (5.6) |
| **Total debt obligations** | | | | | | | 679.8 |
| % of total | 4% | 1% | 22% | 0% | 4% | 69% | 100% |

- The debt maturity is concentrated in 2014 (22% of total).
- However, DBRS believes that the Company's refinancing risk in 2014 is moderate and manageable, given its strong credit profile.

## Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia.

**(1) Transmission**

- The Company owns a 1,400 kilometre transmission system, which is integrated with the BC Hydro system.
- Transmission assets represented approximately 36% of the Company rate base assets (2011).

**(2) Distribution**

- The Company serves approximately 162,000 direct customers, including wholesale customers such as the cities of Kelowna and Nelson.
- Distribution assets represented approximately 36% of the Company's rate base assets (2011).
- Approximately 63% of its power is sold to relatively stable residential and commercial customers, 8% to industrial customers and 29% to wholesale customers, which resell the power to their own residential and commercial customers.
- Approximately 45% of the Company energy needs are supplied from its own generation assets, 27% from the Brilliant hydroelectric plant (contracted until 2056) and 18% from BC Hydro, with the remaining from other sources and the spot market (10%).

**(3) Generation**

- The Company owns four hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs.
- Electricity production from these plants is insulated from hydrology risk as a result of the CPA among BC Hydro, FortisBC and other parties, originally signed in August 1972 and amended in July 2005.
- Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows.
- Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012.

**(4) Non-regulated assets**

- FortisBC also has a limited amount of non-regulated operations, principally made up of Walden Power Partnership (WPP), the owner of an independent power producer.
- The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

**FortisBC Inc.**

**Report Date:**
February 22, 2012

## FortisBC Inc.

| **Balance Sheet** | As at December 31 | | | | As at December 31 | | |
|---|---|---|---|---|---|---|---|
| ($ millions) | 2011 | 2010 | 2009 | **Liabilities & Equity** | 2011 | 2010 | 2009 |
| **Assets** | | | | Short-term debt | 0 | 0 | 0 |
| Cash + equivalents | 0 | 0 | 0 | Debt due one yr. | 25 | 2 | 4 |
| Accounts receivable/unbilled revenue | 39 | 46 | 41 | A/P + accr'ds | 55 | 61 | 49 |
| Inventories | 0 | 0 | 1 | **Current Liabilities** | 80 | 63 | 53 |
| Other | 9 | 3 | 3 | Long-term debt | 587 | 593 | 529 |
| **Current Assets** | 49 | 49 | 45 | Secured debt | 42 | 43 | 44 |
| | | | | Capital lease obligations | 26 | 25 | 29 |
| Net fixed assets | 1,095 | 1,049 | 945 | Other l.t. liabilities | 126 | 113 | 96 |
| Deferred charges/Goodwill | 183 | 173 | 157 | Shareholders' equity | 465 | 434 | 397 |
| **Total** | 1,326 | 1,271 | 1,147 | **Total** | 1,326 | 1,271 | 1,147 |

| **Ratio Analysis** | For the 12-month period ended | | | | | |
|---|---|---|---|---|---|---|
| **Liquidity Ratios** | Dec. 2011 | Dec. 2010 | Dec. 2009 | Dec. 2008 | Dec. 2007 | Dec. 2006 |
| Current ratio | 0.61 | 0.78 | 0.85 | 0.35 | 0.85 | 0.72 |
| Accumulated depreciation/gross fixed assets | 21.4% | 20.6% | 21.4% | 22.1% | 22.0% | 22.7% |
| Cash flow/adjusted debt (1) | 13.3% | 12.4% | 12.2% | 11.4% | 11.4% | 11.2% |
| Cash flow/capital expenditures | 0.95 | 0.59 | 0.69 | 0.62 | 0.45 | 0.53 |
| Cash flow-dividends/capital expenditures | 0.79 | 0.49 | 0.56 | 0.49 | 0.37 | 0.43 |
| % debt in capital structure | 59.4% | 60.5% | 60.4% | 60.4% | 61.1% | 60.9% |
| % adjusted debt in capital structure (1) | 59.8% | 61.0% | 61.0% | 60.9% | 61.7% | 61.6% |
| Deemed common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| | | | | | | |
| **Coverage Ratios** (1) | | | | | | |
| EBIT interest coverage | 2.40 | 2.10 | 2.04 | 2.05 | 2.04 | 2.11 |
| EBITDA interest coverage | 3.52 | 3.21 | 3.06 | 3.09 | 3.04 | 3.09 |
| Fixed-charges coverage | 2.40 | 2.10 | 2.04 | 2.05 | 2.04 | 2.11 |
| Adjusted debt/EBITDA | 4.89 | 5.66 | 5.64 | 5.60 | 5.69 | 5.67 |
| | | | | | | |
| **Earnings Quality/Operating Efficiency** | | | | | | |
| Power purchases/revenues | 25.2% | 28.4% | 29.3% | 29.7% | 31.0% | 32.6% |
| EBIT margin | 33.9% | 30.5% | 29.9% | 29.4% | 28.5% | 27.6% |
| Net margin (before extras) | 16.7% | 16.3% | 14.8% | 14.2% | 13.7% | 12.8% |
| Return on avg. common equity | 10.6% | 10.1% | 9.5% | 9.4% | 9.6% | 9.5% |
| Allowed ROE – mid-point | 9.90% | 9.90% | 8.87% | 9.02% | 8.77% | 9.20% |
| Direct customers/employee | 211 | 210 | 205 | 201 | 202 | 181 |
| Growth of customer base | 0.6% | 1.3% | 1.1% | 2.3% | 1.2% | 1.9% |
| Rate base ($ millions)(2) | 1,093.2 | 975.1 | 908.0 | 822.8 | 747.2 | 676.0 |
| Growth in rate base | 12.1% | 7.4% | 10.4% | 10.1% | 10.5% | 14.3% |

(1) Adjusted for operating leases. (2) Rate base for 2011 was mid-point.

**FortisBC Inc.**

**Report Date:**
February 22, 2012

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Secured Debentures | A (low) | Confirmed | Stable |
| Unsecured Debentures | A (low) | Confirmed | Stable |

## Rating History

| | Current | 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|
| Secured Debentures | A (low) | A (low) | A (low) | BBB (high) | BBB (high) | BBB (high) |
| Unsecured Debentures | A (low) | A (low) | A (low) | BBB (high) | BBB (high) | BBB (high) |

## Related Research

- DBRS Confirms FortisBC at A (low), with a Stable Trend, October 6, 2011.
- DBRS Rates FortisBC Issue of $100 Million 5.00% Medium-Term Notes, Series 2, at A (low), November 19, 2010.

Note:
All figures are in Canadian dollars unless otherwise noted.

Moody's Investors Service

**Global Credit Research**
**Credit Opinion**
22 JUN 2007

**Credit Opinion: FortisBC Inc**

## FortisBC Inc

*British Columbia, Canada*

### Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa2 |

### Contacts

| Analyst | Phone |
|---|---|
| Allan McLean/Toronto | 1.416.214.1635 |
| Catherine N. Deluz/Toronto | |
| William L. Hess/New York | 1.212.553.1653 |

### Key Indicators

**FortisBC Inc**

| | [1]LTM | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense | 3.2x | 3.2x | 3.0x | 2.9x | 2.8x |
| (CFO Pre-W/C) / Debt | 12.0% | 11.9% | 9.6% | 9.8% | 11.0% |
| (CFO Pre-W/C - Dividends) / Debt | 9.9% | 9.9% | 7.9% | 7.3% | 7.6% |
| (CFO Pre-W/C - Dividends) / Capex | 46.5% | 48.4% | 33.2% | 30.9% | 42.2% |
| Debt / Book Capitalization | 64.1% | 64.9% | 66.4% | 66.7% | 67.5% |
| EBITA Margin % | 29.2% | 29.9% | 28.6% | 29.0% | 26.2% |

[1] To March 31, 2007

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

### Opinion

**Company Profile**

FortisBC Inc. (FBC) is a vertically integrated electric utility which is regulated by the British Columbia Utilities Commission (BCUC) under the Utilities Commission Act (the Act). It is an indirect, wholly-owned subsidiary of Fortis Inc. (Fortis, not rated) - a diversified electric and gas utility holding company based in St. John's, Newfoundland.

FBC owns and maintains over 6,750 kilometers of transmission and distribution lines, and delivers electricity to approximately 152,000 commercial and residential customers in the southern interior of British Columbia. The utility owns and operates four low-cost, hydroelectric generating plants with a combined capacity of 235 megawatts. These plants provide approximately 45% of its energy and 30% of its capacity needs. FBC's remaining capacity and energy requirements are acquired through power purchase agreements (PPAs), principally with Brilliant Power Corporation (BPC) and BC Hydro (BCH), and, to a limited degree, spot market purchases. FBC is regulated by the BCUC on a cost of service basis. However, FBC is currently in the second year of a performance based regulation (PBR) agreement that runs until 2008 (2009 if extended by agreement of all interested parties). The PBR mechanism allows for risk sharing within a deadband of plus or minus 2% around FBC's allowed ROE which is 8.77% for 2007.

**Recent Developments**

Since Moody's initial rating of FBC in 2004 (following the acquisition of FBC by Fortis), the firm has made progress on a number of issues that Moody's viewed as being credit concerns. Under Fortis' ownership, FBC has been successful in establishing working relationships with both its regulator and its ratepayers. Forging these relationships was critical to FBC's ability to achieve four consecutive annual rate increases ranging from approximately 3% to 6% per year in support of its relatively large multi-year capital expenditure program. While FBC expects its capex to peak in 2007 at approximately $135 million, Moody's notes that FBC plans, subject to prior BCUC approval, to incur capital expenditures in excess of $500 million during the 2007 to 2011 period. This would cause FBC's ratebase to grow by approximately 40% relative to 2006. While this level of capital expenditure is reflective of the continued need to reinforce FBC's system following a period of under-investment by the previous owner and to respond to the relatively robust growth in portions of its service territory, we note that this level of expenditure continues to be above FBC's expectations for a normalized capital expenditure run rate. Moody's anticipates that this will require ongoing rate increases at levels exceeding the rate of inflation. However, we expect that the magnitude of future rate increases sought by FBC will move closer to the 2% to 3% rate of inflation that the company uses in its financial forecasts instead of the 3% to 6% rate increases that the company has implemented in the last four years. The ongoing elevated capital expenditure plans also mean that FBC will continue to face heightened execution risk (given the inflationary conditions in the labour and materials markets in western Canada) and heightened financing risk. Moody's observes that FBC's reliance on net equity injections by Fortis will be reduced going forward and should be eliminated post 2008.

FBC has improved its liquidity situation since 2004 by procuring a $50 million three year evergreen unsecured revolving term facility in addition to its original $100 million unsecured 364 day revolver which features a six-month term out at FBC's option if not renewed. In addition to expanding its credit facilities, FBC has structured both facilities such that a material adverse change would no longer prevent the company from drawing down on its bank lines. Moody's notes that while the six month term-out feature on the $100 million 364 day facility provides FBC with some time to make alternative arrangements, a twelve month term-out would provide greater flexibility in the context of Moody's standard liquidity stress analysis which examines the firm's ability to meet its obligations for a period of twelve months without access to the debt capital markets.

The negotiated settlement of 2006 allowed FBC to increase its depreciation rate for ratemaking purposes from 2.6% to 3.2%. Despite the increased depreciation rate, the improvement in FBC's cash flow credit metrics has been muted by the impact of declining bond yields on FBC's allowed ROE. This is notwithstanding the fact that the BCUC amended its ROE formula in 2006 resulting in FBC's allowed ROE being approximately 50 BP higher than it would have been under the previously existing ROE formula.

For the 12 month period ended March 31, 2007, FBC's CFO pre-W/C Interest Coverage and CFO pre-W/C /Debt were 3.2x and 12.00% respectively. These levels are somewhat improved from the 2.9x and 9.8% that FBC achieved in 2004 and generally higher than had been forecast by the company in 2004. Based on Moody's review of the company's financial forecasts, we expect that FBC will continue to achieve CFO pre-W/C Interest Coverage of roughly 3.0x and CFO pre-W/C /Debt in excess of 11%. Achievement of these metrics is dependent upon, among other things, long-term bond yields and the allowed ROE generated by the BCUC's ROE formula, execution of BCUC-approved capital spending on or under budget and effective management of forecast risk.

**Rating Rationale**

Pursuant to Moody's Global Regulated Electric Utilities Rating Methodology, FBC is considered to be a lower risk utility given that its operations are virtually entirely regulated and that it operates in a supportive regulatory environment. FBC's ratios are generally consistent with those of other Baa2-rated lower risk electric utilities and generally weaker than its Baa1-rated sister companies, FortisAlberta (FAB) and Newfoundland Power Inc. (NPI). FAB is a pure distribtution utility. NPI is a vertically integrated utility although due to is relatively small generation business, it is predominantly a T&D utility. Comparatively, FAB, NPI and Nova Scotia Power Inc. all have reported CFO pre-W/C /Debt of approximately 15% versus FBC's range in the low teens. The Baa2 rating also reflects the fact that FBC is a small utility relative to its global peers (FBC has less than $1 billion in total assets). Moody's believes that size is an important credit factor in that larger firms typically have a greater depth of management, financial and other resources, enjoy better access to and more diverse sources of capital and are generally better able to deal with any unexpected challenge of a given magnitude relative to smaller firms. FBC's small size is partially offset by the fact that it is part of the Fortis organization which has a market capitalization in excess of $4 billion. While Fortis ensures that its subsidiaries are operationally and financially independent of the parent, Fortis frequently rotates its senior managers through its utility operating subsidiaries for multi-year periods. In addition, Fortis has supported FBC by providing net equity injections in aid of FBC's capital program. The rating also incorporates the fact that FBC's senior unsecured debt is subordinate to FBC's secured debt of which there is approximately $51 million outstanding including the Walden Power Partnership debt. While roughly half of FBC's secured debentures will have been retired by the end of 2013, $25 million of the secured debentures will remain outstanding until 2023. The terms of the senior unsecured trust indenture restrict FBC from issuing further secured debt to fund its growth or refinance the maturing secured debentures.

The Baa2 rating assigned to FBC's senior unsecured debt reflects the company's lower business risk relative to other cost of service-regulated vertically integrated monopoly utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments, a hydro electric utility's greatest risk is hydrology. In FBC's case, hydrology risk is substantially mitigated by the existence of the Canal Plant Agreement (CPA) and FBC's power purchase agreements with BPC and BCH. Under the CPA, which runs until at least 2035, FBC's owned generation is substantially insulated from hydrology risk. Under the CPA, FBC, BPC and others are entitled to receive power from BCH (GRI Aaa, stable) based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. FBC has no hydrology risk exposure under its PPAs with BPC

(Brilliant PPA) and BCH and the costs of these agreements have been approved by the BCUC and are effectively a flow-through to ratepayers. FBC's 235 MW of owned generation supply approximately 45% of its energy requirements, while the Brilliant and BCH PPAs provide approximately 26% and 27% respectively. The balance of approximately 2% is bought from a number of small IPPs and the spot market.

The company has few unregulated operations and those that it does have are viewed to be relatively low risk. These include the provision of operating and maintenance services to owners of hydro electric facilities such as BPC (FBC operates the Brilliant Plant whose entitlement/output is sold to FBC under the long-term Brilliant PPA) and the sale of electricity from the Walden Power hydro-electric IPP to BCH under a long-term PPA.

The company's location in British Columbia, which enjoys a strong provincial economy and supportive regulatory climate, contributes to Moody's view of FBC as a lower risk utility. Moody's considers Canada generally to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced. FBC annually reviews its capital spending plans and the rate impacts thereof with the BCUC, a process which substantially reduces the risk of being unable to fully recover costs that have already been incurred.

The rating considers FBC's status as a subsidiary of its parent, Fortis Inc., a utility holding company. While FBC is one of a number of utility operating companies owned by Fortis, Moody's considers FBC, like FAB and NPI, to be operationally and financially independent from Fortis Inc. (notwithstanding that net equity injections to FBC by Fortis Inc. are expected to occur until 2008). While Fortis could seek to increase dividends payments from FBC to support the operations of the holding company or other utility operating companies, the current expectation is that dividends will not exceed the level necessary to maintain FBC's 60/40 target capital structure (40% is the maximum equity permitted by the BCUC for ratemaking purposes). Furthermore, FBC is protected by a degree of covenant ring-fencing in its credit agreements. FBC's bank credit agreement contains safeguards which prohibit loans to affiliates or guarantees of affiliate debt. The credit agreement also places meaningful restrictions on all other affiliate transactions. Overall, Moody's considers FBC's access to the financial resources and executive support of Fortis to be a credit strength. Fortis has consistently demonstrated good management and support of its subsidiaries, and the ability to maintain, and in some cases rebuild, good relationships with regulators.

Moody's views FBC's expanded liquidity facilities (described above under Recent Events) to be satisfactory for its Baa2 rating. The liquidity facilities will be utilized in part to fund FBC's System Development Plan which, subject to prior BCUC approval, includes capital expenditures in excess of $500 million in the next five years. FBC expects to periodically issue additional senior unsecured debentures to refund borrowings under the syndicated credit facility. As at March 31, 2007, approximately $12 million was drawn against the operating credit facilities and $4.6 million was used to support outstanding letters of credit.

FBC is expected to maintain cash flow coverage metrics appropriate for a lower risk Baa2-rated utility. The CFO pre-W/C Interest Coverage is expected be approximately 3.0 times or higher and CFO pre-W/C /Debt is expected to be 11% or more. FBC's challenge will be to manage execution risk related to its ongoing substantial capital expansion program given the difficult inflationary environment in western Canada. While ratepayer fatigue is a potential risk given FBC's four consecutive annual rate increases (ranging from 3% to 6%), Moody's believes that this risk is largely mitigated by FBC's regulatory framework. Each year FBC reviews its capital expenditure plans with the BCUC and receives approval for those plans. Once the capital spending plans are approved by the BCUC, it would seem relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. Accordingly, Moody's believes that the greatest risk related to FBC's capital expenditure plans is the incurrence of cost overruns, the recovery of which might not be permitted by the BCUC.

**Rating Outlook**

The rating outlook is stable based on the expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened.

**What Could Change the Rating - Up**

The rating could be positively impacted if FBC could demonstrate expectations for a sustained improvement in financial ratios, such as CFO pre-W/C /Debt in the mid to high teens and CFO pre-W/C Interest Coverage approaching 3.5 times or more.

**What Could Change the Rating - Down**

FBC's rating could be negatively impacted by expectations of a sustained weakening of its financial metrics such as CFO pre-W/C /Debt below 11% and CFO pre-W/C Interest Coverage below 3.0 times.

**Rating Factors**

**FortisBC Inc**

**Select Key Ratios for Global Regulated Electric Utilities**

| Rating | Aa | Aa | A | A | Baa | Baa | Ba | Ba |
|---|---|---|---|---|---|---|---|---|
| **Level of Business Risk** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** |
| CFO pre-W/C to Interest (x) [1] | >6 | >5 | 3.5-6.0 | 3.0-5.7 | 2.7-5.0 | 2-4.0 | <2.5 | <2 |
| CFO pre-W/C to Debt (%) [1] | >30 | >22 | 22-30 | 12-22 | 13-25 | 5-13 | <13 | <5 |
| CFO pre-W/C - Dividends to Debt (%) [1] | >25 | >20 | 13-25 | 9-20 | 8-20 | 3-10 | <10 | <3 |
| Total Debt to Book Capitalization (%) | <40 | <50 | 40-60 | 50-75 | 50-70 | 60-75 | >60 | >70 |

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

**Credit Opinion: FortisBC Inc**

**FortisBC Inc**

*British Columbia, Canada*

## Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa2 |

## Contacts

| Analyst | Phone |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| William L. Hess/New York | 212.553.3837 |

## Key Indicators

**FortisBC Inc**

| | [1]LTM | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense (x) [2][3] | 2.8x | 2.8x | 2.8x | 2.5x | 2.6x |
| (CFO Pre-W/C) / Debt (%) [2] | 11.0% | 10.9% | 11.5% | 8.9% | 9.2% |
| (CFO Pre-W/C - Dividends) / Debt (%) [2] | 8.8% | 8.8% | 9.4% | 7.2% | 6.7% |
| Debt / Book Capitalization 9%) | 63.9% | 64.4% | 65.1% | 67.5% | 67.0% |

[1] Last twelve months to March 31, 2008 [2] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [3] Interest includes implied interest on operating leases and capitalized interest.

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

## Opinion

### Company Profile

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated electric utility that operates under a primarily cost-of-service regulatory regime as administered by the British Columbia Utilities Commission (BCUC) under the Utilities Commission Act (the Act). It is an indirect, wholly owned subsidiary of Fortis Inc. (FTS), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

FBC owns and maintains over 6,900 kilometers of transmission and distribution lines, and delivers electricity to approximately 154,000 direct and indirect residential, general service and, industrial customers in the southern interior of British Columbia. FBC also owns and operates four low-cost, hydroelectric generating plants with a combined capacity of 223 megawatts. These plants provide 45% of its energy and 30% of its capacity needs. FBC's remaining capacity and energy requirements are acquired through power purchase agreements (PPAs), principally with Brilliant Power Corporation (BPC) and British Columbia Hydro and Power Authority (BCH), and, to a limited degree, though spot market purchases. With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the Province of British Columbia. In Moody's view, FBC operates in a relatively supportive regulatory environment in which there is limited risk of industry restructuring or political interference.

FBC is regulated primarily on a cost-of-service basis, although a limited performance based regulation (PBR) agreement commenced in 2006 and expires at the end of 2008 unless extended to 2009 upon the agreement all interested parties. The PBR agreement provides that the operations and maintenance component of FBC's revenue requirement is set by formula while all other components of FBC's revenue requirement are forecast on an annual basis. Under the PBR agreement, FBC shares equally with ratepayers any over/under earnings within a 4% band (i.e. from -2% to +2%) around its allowed ROE (9.02% for 2008 up from 8.77% in 2007). The BCUC allows for differences in risk between utilities by varying the capital structures, and in some instances, the allowed ROEs of the utilities. FBC's deemed capital structure is currently 60% debt and 40% equity.

**Recent Developments**

On October 1, 2007, FBC filed its Preliminary 2008 Revenue Requirement application and subsequently updated the application on November 1, 2007. On December 4, 2007, following a negotiated settlement process with intervenors, the BCUC approved the settlement agreement providing FBC with a 2.9 % rate increase effective January 1, 2008. The 2008 rate increase is attributed primarily to FBC's continuing capital investment program as well as the higher allowed ROE for 2008.

FBC has indicated that it intends to file its 2009 Revenue Requirements Application as well as its 2009/2010 Capital Plan with the BCUC in the third quarter of 2008.

**Rating Rationale**

The Baa2 rating of FBC's senior unsecured debt reflects Moody's view of FBC's regulatory, market, business, and financial positions pursuant to Moody's methodology for the Global Regulated Electric Utility industry. FBC is considered to be a lower risk utility given that its operations are virtually entirely regulated and located in Canada, a jurisdiction that Moody's generally views as being one of the more supportive regulatory environments for utilities on a global basis.

Key rating factors forming the basis of FBC's rating and outlook are:

BUSINESS IS VIRTUALLY ENTIRELY REGULATED AND DOMICILED IN A SUPPORTIVE REGULATORY ENVIRONMENT

FBC's low business risk position reflects the fact that the company's unregulated operations are limited and low risk in nature. FBC's only unregulated activity is the sale of electricity from the Walden Power hydroelectric IPP under a long-term PPA with BCH (Aaa).

Moody's considers FBC's business risk to be lower than that of other cost of service-regulated vertically integrated monopoly utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments, a hydroelectric utility's greatest risk is hydrology. In FBC's case, hydrology risk is substantially mitigated by the existence of the Canal Plant Agreement (CPA) and FBC's power purchase agreements with BPC and BCH. Under the CPA, which runs until at least 2035, FBC's owned generation is substantially insulated from hydrology risk. Under the CPA, FBC, BPC and others are entitled to receive power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. FBC has no hydrology risk exposure under its purchase power agreements with BPC and BCH which provide approximately 26% and 27.5% respectively of FBC's annual energy requirements.

FBC's location in British Columbia, which enjoys a strong provincial economy and supportive regulatory climate, contributes to Moody's view of FBC as a lower risk utility. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced. Historically, the strong growth within FBC's franchise area has not taxed the company either operationally or financially and net equity injections from FTS have been received on a consistent basis allowing the company to remain close to its target 60/40 capital structure.

FLEXIBILITY TO RECOVER COSTS AND EARN RETURNS

FBC is regulated primarily on a cost of service basis although there are limited performance based rate-making provisions in place relative to operating and maintenance (O&M) expenses. The PBR mechanism was negotiated in 2006 and under this agreement FBC has achieved actual ROEs in excess of its allowed ROEs in both 2006 and 2007. In its annual revenue requirements applications, FBC forecasts costs other than O&M and has the ability to recover or refund variations between certain forecast and actual revenues and expenses thereby mitigating, to a degree, its exposure to forecast risk. The PBR mechanism runs through calendar 2008 although it contemplates a one-year extension to 2009 upon the mutual agreement of FBC, the BCUC and ratepayers.

Purchased power costs are FBC's single largest expense item. Certainty of recovery of these costs is high due to the fact that the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan and its rate impacts are reviewed annually, a process which substantially reduces the risk of being unable to fully recover capital investments that have already been incurred.

FBC tends to recover its costs on a timely basis as evidenced by the fact that regulatory assets represent a relatively small proportion of total assets.

LIMITED DIVERSIFICATION BY MARKET, REGULATORY JURISDICTION AND GENERATION TECHNOLOGY

Diversification of a company's operations by market, geographic region, regulatory regime or by generation technology are factors considered by Moody's in assessing the predictability and stability of a company's cash flows. A vertically integrated electric utility, FBC operates solely in the province of British Columbia and therefore has no diversification by market or regulatory jurisdiction. However, Moody's believes that FBC's lack of diversification is somewhat offset by certain characteristics of its business, market and regulatory regime. With the exception of BCH which is 100% owned by the government of British Columbia, the company's dominant position as the only integrated regulated electric utility operating in British Columbia, a province with above average economic growth, mitigates potential loss of market share by competition. Furthermore, although FBC relies on a single type of generation for its fuel source, it has minimal exposure to commodity prices and hydrology risk by virtue of the CPA and its PPAs with highly-rated counterparties.

CONSISTENT BUT RELATIVELY WEAK FINANCIAL METRICS

FBC's ratios are generally consistent with those of other Baa2 lower risk electric utilities such as Emera (EMA) and generally weaker than those of its Baa1-rated sister companies, FortisAlberta (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). Comparatively, FAB, NPI and Nova Scotia Power Inc. (NSP) are expected to generate CFO pre-W/C to Debt in excess of 15% versus FBC's range in the low teens. For the full year ending 2007, FBC achieved CFO pre-W/C to Debt of 10.9% and CFO pre-W/C Interest Coverage of 2.8x. These levels are somewhat improved from the 2.4x and 9.9% that FBC achieved in 2004 following its acquisition by FTS and generally higher than had been forecast by the company in 2004. Forecast financial metrics, including expected ratios of CFO pre-W/C to Debt in excess of 11% and Interest Coverage of approximately 3.0x, remain consistent with a Baa2 senior unsecured rating under Moody's global rating methodology for electric utility companies. Achievement of these metrics is dependent upon, among other things, long-term bond yields and the allowed ROE generated by the BCUC's ROE formula, execution of BCUC-approved capital spending on, or under budget as well as effective management of forecast risk. However, Moody's notes that FBC has historically consistently over earned on its allowed ROE.

FBC's challenge will be to continue to successfully manage execution risk related to its ongoing capital expansion program given the difficult inflationary environment in western Canada. Capital expenditures are expected to result in negative free cash flow necessitating continued net equity injections from FTS in order to maintain FBC's target 60/40 capital structure. There is a risk that continued elevated capital expenditures, which are expected to necessitate rate increases above the level of inflation, could lead to ratepayer fatigue. However, this risk should be mitigated by the BCUC's annual reviews of FBC's capital plan. Once the capital spending plans are approved by the BCUC, it would seem relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. Accordingly, Moody's believes that the greatest risk related to FBC's capital expenditure plans is to avoid cost overruns, the recovery of which might not be permitted by the regulator.

LIQUIDITY ARRANGEMENTS ARE A RELATIVE WEAKNESS

In evaluating a company's liquidity, Moody's typically assumes that the company loses access to new debt capital, other than credit available under its committed credit agreements, for a period of 12 months. In this context, we then evaluate the company's various sources and uses of cash including the flexibility to defer or reduce uses of cash such as capital expenditures and dividends.

FBC is expected to generate approximately $65 million of adjusted funds from operations (FFO) in the next 12 months. After dividends in the range of $13 million and capital expenditures plus working capital changes of approximately $134 million, Moody's expects FBC to be free cash flow (FCF) negative by approximately $80 million in the next year.

The majority of FBC's long-term debt is in the form of senior secured and senior unsecured debentures. Moody's anticipates that FBC will periodically issue additional senior unsecured debentures to refund scheduled debt maturities, term-out borrowings under the syndicated credit facility and fund the company's large capital expenditure program. FBC has no significant scheduled debt maturities until July, 2009 when $50 million of unsecured debentures mature.

FBC's core liquidity facility is a syndicated committed credit agreement comprised of a $50 million three year revolving term facility and a $100 million 364-day revolving facility. These facilities mature on May 11, 2011 and May 7, 2009 respectively and the revolving periods of the these facilities can only be extended with the Lenders' consent. The credit agreement contains an accordion feature that would allow FBC to request (but not obligate the lenders to provide) an additional $50 million of committed funding under either of the facilities. Further, FBC has structured the credit agreement such that a material adverse change would not prevent the company from drawing down on either facility.

FBC's $100 million 364-day revolver features an automatic six-month non-revolving term out if the revolving period is not extended for an additional 364 day period. Moody's notes that while the six month term-out feature provides

FBC with some time to make alternative arrangements, a twelve month term-out would provide greater flexibility in the context of Moody's standard liquidity stress analysis which examines the firm's ability to meet its obligations for a period of twelve months. We note that the core liquidity facilities of virtually all of the Canadian utilities rated by Moody's are either multi-year credit facilities or, at minimum, 364-day facilities that provide the borrower with a 12-month term out capability in the event of non-renewal of the revolving period.

The liquidity facilities will be utilized in part to fund FBC's System Development Plan which, subject to prior BCUC approval, includes annual capital expenditures of approximately $135 to $160 million in the near to medium term and approximately $500 million in aggregate over the next five years. As at March 31, 2008, FBC had approximately $4.6 million of short-term debt and $3 million of letters of credit outstanding. For purposes of Moody's liquidity stress scenario, we consider both of these amounts as reducing the availability remaining under the company's committed credit facilities. Therefore, in Moody's view, FBC had approximately $142 million of remaining committed credit at March 31, 2008, which was sufficient to meet the company's funding requirements under our liquidity stress scenario. However, Moody's anticipates that unless FBC raises term debt on a relatively frequent basis the company's liquidity will become strained by its ongoing capital program. Moody's understands that FBC would have the ability to temporarily defer elements of its capital program such as generation life extension and transmission upgrade expenditures in the event of liquidity stress. However, Moody's observes that reliance on capital expenditure reductions represents a less robust form of liquidity than maintaining higher levels of committed credit facilities with multi-year maturities or a term-out option of one or more years.

OPERATIONAL AND FINANCIAL INDEPENDENCE FROM PARENT, FORTIS INC.

While FBC is one of a number of utility operating companies owned by FTS, Moody's considers FBC, like its sister companies FAB, NPI, Terasen Gas Inc. (TGI), and Terasen Gas (Vancouver Island) Inc. (TGVI), to be operationally and financially independent from FTS (notwithstanding that net equity injections to FBC by FTS are expected to continue for several years). This is consistent with FTS' philosophy of allowing its utility subsidiaries to operate on a stand-alone basis.

FTS has consistently demonstrated good management and support of its subsidiaries, as well as the ability to maintain or rebuild good relationships with regulators of the companies that FTS has acquired. Although FTS could seek to increase dividend payments from FBC to support the operations of the holding company or other utility operating companies, Moody's expects that FTS will continue to allow FBC to pursue a dividend policy which will maintain its 60/40 target capital structure. Furthermore, FBC is insulated to a degree from the credit profile of its parent by certain covenants in its credit agreement. FBC's bank credit agreement contains safeguards which prohibit affiliate loans and guarantees and place meaningful restrictions on all other affiliate transactions. Overall, Moody's considers FBC's access to the financial resources and executive support of FTS to be a credit strength.

Since its acquisition by FTS, FBC has been successful in establishing working relationships with both its regulator and its ratepayers. Forging these relationships has been critical to FBC's ability to achieve five consecutive annual rate increases ranging from approximately 3% to 6% per year in support of its relatively large multi-year capital expenditure program. Moody's notes that FBC plans, subject to prior BCUC approval, to incur capital expenditures of more than $500 million during the 2008 to 2012 period. While this level of capital expenditure is reflective of the continued need to reinforce FBC's system following a period of under-investment by the previous owner and to respond to the relatively robust growth in portions of its service territory, we note that this level of expenditure continues to be above FBC's expectations for a normalized capital expenditure run rate.

SUBORDINATION

FBC's rating also incorporates the fact that the company's senior unsecured debt is subordinate to its secured debt comprised of $44.5 million secured debentures and approximately $5 million mortgage debt at the Walden Power IPP. While roughly half of the secured debentures will have been retired by the end of 2013, $25 million of the secured debentures will remain outstanding until 2023. The terms of the senior unsecured trust indenture restrict FBC from issuing further secured debt to fund its growth or refinance the maturing secured debentures.

**Rating Outlook**

The rating outlook is stable based on Moody's expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened.

**What Could Change the Rating - Up**

The rating could be positively impacted if FBC could demonstrate expectations for a sustainable improvement in financial ratios, such as CFO pre-W/C to Debt in the mid teens and CFO pre-W/C Interest Coverage approaching 3.5 times.

**What Could Change the Rating - Down**

Expectations of sustained weakening of FBC's CFO pre-W/C to Debt ratio below 11% and CFO pre-W/C Interest coverage of below 3.0x could place downward pressure on FBC's rating. Although considered unlikely, the company's Baa2 rating could also be negatively impacted by adverse regulatory developments such as reductions in deemed equity or depreciation rates and increasing regulatory lag for recovery of costs and outlays. Failure of FBC to restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened would also have an adverse impact on the company's rating.

## Rating Factors

**FortisBC Inc**

**Select Key Ratios for Global Regulated Electric Utilities**

| Rating | Aa | Aa | A | A | Baa | Baa | Ba | Ba |
|---|---|---|---|---|---|---|---|---|
| **Level of Business Risk** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** |
| CFO pre-W/C to Interest (x) [1][2] | >6 | >5 | 3.5-6.0 | 3-5.7 | 2.7-5.0 | 2-4.0 | <2.5 | <2 |
| CFO pre-W/C to Debt (%) [1] | >30 | >22 | 22-30 | 12-22 | 13-25 | 5-13 | <13 | <5 |
| CFO pre-W/C - Dividends to Debt (%) [1] | >25 | >20 | 13-25 | 9-20 | 8-20 | 3-10 | <10 | <3 |
| Total Debt to Book Capitalization (%) | <40 | <50 | 40-60 | 50-75 | 50-70 | 60-75 | >60 | >70 |

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Interest includes implied interest on operating leases and capitalized interest.

Global Credit Research
Credit Opinion
29 JAN 2009

**Credit Opinion: FortisBC Inc**

**FortisBC Inc**

*British Columbia, Canada*

**Ratings**

| **Category** | **Moody's Rating** |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa2 |

**Contacts**

| **Analyst** | **Phone** |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| William L. Hess/New York | 212.553.3837 |

**Key Indicators**

**FortisBC Inc**

| | [1]**LTM** | **2007** | **2006** | **2005** | **2004** |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense (x) [2][3] | **2.8x** | **2.8x** | **2.8x** | **2.5x** | **2.6x** |
| (CFO Pre-W/C) / Debt (%) [2] | **11.2%** | **10.9%** | **11.5%** | **8.9%** | **9.2%** |
| (CFO Pre-W/C - Dividends) / Debt (%) [2] | **8.9%** | **8.8%** | **9.4%** | **7.2%** | **6.7%** |
| Debt / Book Capitalization 9%) | **63.1%** | **64.4%** | **65.1%** | **67.5%** | **67.0%** |

[1] Last twelve months to September 30, 2008 [2] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [3] Interest includes implied interest on operating leases and capitalized interest.

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

**Opinion**

**Rating Drivers**

Low-risk utility that operates in a relatively supportive regulatory environment in which there is limited risk of industry restructuring or political interference.

Relatively weak credit metrics.

Negative free cash flow due to continued elevated capital expenditure levels during the next five years related to the reinforcement and expansion of its system.

Relatively weak liquidity arrangements with reliance to some degree on external funding sources and continued net equity injections from parent in the near to medium term.

**Corporate Profile**

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated regulated hydroelectric utility that operates primarily under a cost-of-service regulatory regime. FBC is an indirect, wholly-owned subsidiary of Fortis Inc. (FTS), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

**SUMMARY RATING RATIONALE**

The Baa2 senior unsecured rating of FBC reflects the low-risk nature of the utility wherein over 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low-risk. The rating also considers FBC's location in a supportive regulatory environment with a limited performanced based regulatory regime that has allowed FBC to consistently earn more than its allowed return on equity (ROE) since 2004. FBC's credit metrics have demonstrated positive progress since 2004; however, they continue to be weak relative to peers. FBC's capital spending has been elevated since 2004 and is expected to remain elevated through the medium-term due to significant investments to strengthen its existing system and accommodate relatively strong growth within its service territory. As a result, the company is expected to produce relatively large free cash flow deficits during the next five years. In this context, FBC's liquidity is considered to be relatively weak. The foregoing factors are the primary drivers of FBC's Baa2 senior unsecured rating. Moody's does not foresee any significant change in these key ratings drivers in the near to medium-term.

**DETAILED RATING CONSIDERATIONS**

PREDOMINANTLY REGULATED UTILITY OPERATING IN A SUPPORTIVE REGULATORY ENVIRONMENT

FBC's rating reflects the company's low business risk profile where over 95% of its operations are regulated and its unregulated operations are limited and low-risk in nature. FBC's only unregulated activity is the sale of electricity from the Walden Power hydroelectric independent power producer (IPP) under a long-term power purchase agreement (PPA) with British Columbia Hydro & Power Authority (BCH; Aaa, stable). With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the province of British Columbia.

Moody's considers FBC's business risk to be lower than that of other cost of service-regulated vertically integrated utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments, a hydroelectric utility's greatest risk is hydrological risk where uncertainty associated with accurately estimating hydrology in a given timeframe that could adversely impact generation operations if forecasted conditions diverge significantly from actual conditions. FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement (CPA) and its PPAs with Brilliant Power Corporation (BPC; A1, stable) and BCH which provide approximately 26% and 27.5%, respectively, of FBC's annual energy requirements. The CPA runs until at least 2035 and entitles FBC, BPC and others to receive power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. Under the CPA, FBC's owned generation is substantially insulated from hydrology risk.

FBC's location in British Columbia, which enjoys a strong provincial economy and supportive regulatory climate, contributes to Moody's view of FBC as a lower risk utility. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in British Columbia is considered one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced with minimal regulatory lag. Historically, FBC has been able to achieve five consecutive annual rate increases ranging from approximately 3% to 6% per year in support of its relatively large multi-year capital expenditure program.

RELATIVELY WEAK FINANCIAL METRICS COMPARED TO PEERS

FBC's credit metrics have demonstrated modest improvement since 2004 although its ratios continue to be weak relative to peers and are not expected to strengthen materially in the near to medium-term. FBC's relatively weak financial profile is offset by the company's location in a supportive regulatory environment with a regime that allows it to consistently exceed its allowed ROE and recover costs in a timely manner. FBC's allowed ROE is determined by the BCUC's annual automatic adjustment mechanism which, for 2009, is 8.87% on a deemed 60% debt to 40% equity capital structure.

FBC is regulated primarily on a cost of service basis although there are limited performance based rate-making provisions in place relative to operating and maintenance (O&M) expenses. FBC's recently approved 2009 rate increase of 4.6% also included a three year extension of the Performance Based-Rate (PBR) mechanism through to the end of 2011. To a degree, the regulatory regime mitigates FBC's exposure to forecast risk by allowing the company to forecast costs other than O&M in its annual revenue requirements application and then recover or refund variations between certain forecast and actual revenues and expenses. Under the PBR agreement, FBC has historically been able to achieve actual ROEs in excess of its allowed ROEs in the last few years.

FBC's largest expense item is purchased power, however, certainty of recovery of these costs is high because the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan and its rate impacts are reviewed annually, a process which substantially reduces the risk of being unable to fully recover capital investments that have already been incurred.

FBC's ratios are generally consistent with those of its Canadian electric utility peers and other Baa2 lower-risk electric utilities but weaker than its Baa1-rated sister companies, FortisAlberta Inc. (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). For example, FAB and NPI have reported CFO pre-W/C to Debt of approximately 14% while FBC's range is in the low teens. Moody's expects FBC's forecast financial metrics, including expected ratios of CFO pre-W/C to Debt in the range of 11% and Interest Coverage of approximately 3.0x, to remain consistent with a Baa2 senior unsecured rating under Moody's global rating methodology for electric utility companies. Achievement of these metrics is dependent upon, among other things, the allowed ROE generated by the BCUC's ROE formula, execution of BCUC-approved capital spending on, or under budget as well as effective management of forecast risk.

SIGNIFICANT CAPITAL EXPENDITURES DURING THE NEXT FIVE YEARS

FBC's challenge will be to continue to successfully manage its relatively large capital expenditure program. While this elevated level of capital expenditure is reflective of the continued need to reinforce FBC's system following a period of under-investment by the previous owner and in response to the growth in portions of its service territory, we note that this level of expenditure continues to be above FBC's expectations for a normalized capital expenditure run rate.

FBC's forecasted capital expenditures are expected to result in relatively large free cash flow deficits necessitating continued net equity injections from FTS for the next few years in order to maintain FBC's target 60/40 capital structure. Further, there is a risk that continued elevated capital expenditures, which are expected to necessitate rate increases above the level of inflation, could lead to ratepayer fatigue. However, this risk should be significantly mitigated by the BCUC's review and approval of FBC's two-year capital plan and its annual review of FBC's spending plans as part of the annual revenue requirements application process. Once the capital spending plans are approved by the BCUC, Moody's believes that it is relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. Accordingly, Moody's believes that the greatest risk related to FBC's capital expenditure plans is the company's ability to prudently manage its projects to avoid excessive cost overruns, the full recovery of which might not be permitted by the regulator.

RELATIVELY WEAK LIQUIDITY WITH RELIANCE ON CONTINUED CAPITAL CONTRIBUTIONS FROM PARENT

FBC's liquidity arrangements are relatively weak because the combination of retained cash flow and committed credit facilities are not always sufficient to cover its capital expenditures and scheduled debt maturities under Moody's liquidity stress scenario.

FBC's core liquidity facility is a syndicated committed credit agreement comprised of a $50 million three- year revolving term facility and a $100 million 364-day revolving facility. These facilities mature on May 11, 2011 and May 7, 2009, respectively, and the revolving periods of these facilities can only be extended with the Lenders' consent. FBC has structured the credit agreement such that a material adverse change would not prevent the company from drawing down on either facility.

FBC's $100 million 364-day revolver features an automatic six-month non-revolving term-out if the revolving period is not extended for an additional 364 day period. Moody's notes that a 12-month term-out would provide greater flexibility in the context of Moody's standard liquidity stress analysis which examines the firm's ability to meet its obligations for a period of twelve months. Moody's further notes that the core liquidity facilities of virtually all of the Canadian utilities rated by Moody's are either multi-year credit facilities or, at minimum, 364-day facilities that provide the borrower with a 12-month term out capability in the event of non-renewal of the revolving period.

FBC's liquidity facilities will be utilized to fund a portion of the company's capital program which envisions forecast capital expenditures of approximately $700 million over the next five years, subject to regulatory approval. Moody's understands that FBC has the ability to temporarily defer elements of its capital program and O&M costs, suspend dividend payments to FTS and/or request additional equity injections or loans from FTS in the event of liquidity stress. Nevertheless, Moody's observes that reliance on capital expenditure reductions, dividend deferrals and equity injections represent less robust forms of liquidity than maintaining higher levels of committed credit facilities with multi-year maturities or a term-out option of one or more years.

Moody's considers FBC's access to the financial resources and executive support of its parent, FTS, to be a credit strength. Regardless of the fact FBC is insulated to a degree from the credit profile of its parent by certain covenants in its credit agreement, FTS has nonetheless consistently demonstrated good management and support of its subsidiaries and the ability to maintain or rebuild good relationships with regulators. While FTS could seek to increase dividends from FBC to support the operations of the parent or sister subsidiaries, the expectation is that dividends will not exceed the level necessary to maintain FBC's 60/40 target capital structure. Moody's also expects FTS will continue to contribute capital as needed in order to allow FBC to remain close to its deemed capital structure. FTS maintains a $600 million 5 year committed credit facility, which can be made available to lend to its subsidiaries.

**Liquidity Profile:**

FBC's liquidity arrangements are relatively weak in the context of its forecast capital expenditures and scheduled debt maturities.

During 2009, FBC is expected to generate approximately $70 million of adjusted funds from operations (FFO). After dividends in the range of $14 million and capital expenditures plus working capital changes of approximately

$144 million, Moody's expects FBC to be free cash flow (FCF) negative by approximately $86 million in 2009. In addition, FBC has a $50 million scheduled debt maturity in July, 2009..

At September 30, 2008, FBC had approximately $16.8 million of drawings outstanding and $3 million of letters of credit issued against its bank facilities. For purposes of Moody's liquidity stress scenario, we consider both of these amounts as a reduction of the available amount remaining under the company's total committed credit facilities of $150 million. If Moody's forecasts a reduction of a similar magnitude in FBC's facilities for the year ended, December 31, 2008, and if FBC's 364-day facility is not renewed in May, 2009, the company's level of remaining committed credit would be less than sufficient to meet the company's 2009 funding requirements under Moody's liquidity stress scenario. Moody's anticipates, however, that FBC will issue debt in advance of its $50 million debt maturity and that it will seek to renew its 364-day facility, or if necessary, replace the amount of facility with another source of liquidity. In the event that FBC is not able to access the capital markets in advance of its debt maturity and/or is unable to extend its 364-day bank facility, we expect that the company would seek to access alternative liquidity in the form of capital expenditure reductions, dividend deferrals and/or equity injections as discussed above.

**Rating Outlook**

The rating outlook is stable based on Moody's expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened.

**What Could Change the Rating - Up**

The rating could be positively impacted if FBC were to strengthen its liquidity arrangements and be able to demonstrate a sustainable improvement in financial ratios, such as CFO pre-W/C to Debt of approximately 12% and CFO pre-W/C Interest Coverage in excess of 3.0 times.

**What Could Change the Rating - Down**

Expectations of sustained weakening of FBC's CFO pre-W/C to Debt ratio below 10% and CFO pre-W/C Interest coverage of below 2.8x could place downward pressure on FBC's rating. Although considered unlikely, the company's Baa2 rating could also be negatively impacted by adverse regulatory developments and increasing regulatory lag for recovery of costs and outlays. Failure of FBC to restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened would also have an adverse impact on the company's rating.

**Rating Factors**

**FortisBC Inc**

**Select Key Ratios for Global Regulated Electric Utilities**

| **Rating** | **Aa** | **Aa** | **A** | **A** | **Baa** | **Baa** | **Ba** | **Ba** |
|---|---|---|---|---|---|---|---|---|
| **Level of Business Risk** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** | **Medium** | **Low** |
| CFO pre-W/C to Interest (x) [1][2] | >6 | >5 | 3.5-6.0 | 3-5.7 | 2.7-5.0 | 2-4.0 | <2.5 | <2 |
| CFO pre-W/C to Debt (%) [1] | >30 | >22 | 22-30 | 12-22 | 13-25 | 5-13 | <13 | <5 |
| CFO pre-W/C - Dividends to Debt (%) [1] | >25 | >20 | 13-25 | 9-20 | 8-20 | 3-10 | <10 | <3 |
| Total Debt to Book Capitalization (%) | <40 | <50 | 40-60 | 50-75 | 50-70 | 60-75 | >60 | >70 |

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Interest includes implied interest on operating leases and capitalized interest.

**WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.**

Moody's
INVESTORS SERVICE

## Credit Opinion: FortisBC Inc

Global Credit Research - 06 May 2010

*British Columbia, Canada*

### Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa1 |

### Contacts



| Analyst | Phone |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| Donald S. Carter, CFA/Toronto | 416.214.3851 |



### Key Indicators

[1]**FortisBC Inc**

| | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense | 2.9x | 2.7x | 2.8x | 2.8x | 2.5x |
| (CFO Pre-W/C) / Debt | 11.9% | 11.2% | 10.9% | 11.5% | 8.9% |
| (CFO Pre-W/C - Dividends) / Debt | 9.6% | 8.9% | 8.8% | 9.4% | 7.2% |
| Debt / Book Capitalization | 59.4% | 63.8% | 64.4% | 65.1% | 67.5% |

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

### Opinion

#### Rating Drivers

Low-risk utility operating in a supportive regulatory environment

Relatively weak quantitative credit metrics are expected to improve modestly

Growth in rate base and cash flow expected to result in smaller free cash flow deficits

Improved credit facilities result in a satisfactory liquidity position

#### Corporate Profile

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated regulated hydro-electric utility that operates primarily under a cost-of-service regulatory regime. FBC is an indirect, wholly-owned subsidiary of Fortis Inc. (FTS, unrated), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

## SUMMARY RATING RATIONALE

The Baa1 senior unsecured rating of FBC reflects the low-risk nature of the utility where over 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low-risk. The rating also considers FBC's location in a supportive regulatory environment with a limited performance based regulatory regime that has allowed FBC to consistently earn more than its allowed return on equity (ROE) since 2003. These strengths are offset by quantitative credit metrics that remain weak relative to those of peers, despite a gradual improvement in recent years. Over the past five years, FBC's investment program has resulted in a 70% increase in rate base assets and steady growth in cash flow from operations. FBC's capital spending will remain elevated in the medium term as the company continues to invest to strengthen its existing system and accommodate relatively strong growth within its service territory but the planned spending is more manageable in the context of its current rate base and cash flow. The increase in FBC's allowed ROE to 9.9% for 2010 is expected to modestly improve metrics in 2010 and beyond. We expect credit metrics to show further modest improvement as FBC's cash flow continues to grow due to both historic and forecast capital spending. Higher cash flow from FBC's larger rate base should result in smaller free cash flow deficits going forward. In our view, FBC's liquidity resources are sufficient given the changes to its credit agreement announced in April 2010.

## DETAILED RATING CONSIDERATIONS

### PREDOMINANTLY REGULATED UTILITY OPERATING IN A SUPPORTIVE REGULATORY ENVIRONMENT

FBC's rating reflects the company's low business risk profile where over 95% of its operations are regulated and its unregulated operations are limited and low-risk in nature. FBC's primary unregulated activity is the sale of electricity from the Walden Power hydro-electric independent power project (IPP) under a long-term power purchase agreement (PPA) with British Columbia Hydro & Power Authority (BCH; Aaa, stable). With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the province of British Columbia.

Moody's considers FBC's business risk to be lower than that of other cost-of-service regulated vertically integrated utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments (fuel purchase and electricity sales), a hydro-electric utility's greatest risk is hydrology. Actual water flows can vary significantly from those forecast with significant cash flow repercussions. However, FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement (CPA), which runs until at least 2035. Under the CPA, FBC and others cede scheduling control of their generation facilities to BCH in exchange for power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. The hydro-electric generation facilities owned by FBC provide about 45% of its annual energy requirement. The PPAs with BCH and Brilliant Power Corporation (BPC, A1, stable) provide the bulk of the balance of FBC's requirements, representing approximately 24% and 26% respectively of its annual energy requirements.

FBC's location in British Columbia, which, until recently, enjoyed a relatively strong provincial economy and continues to enjoy a supportive regulatory climate, contributes to our view of FBC as a lower risk utility. We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in British Columbia is considered one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced with minimal regulatory lag. The progress of FBC's 2010 Revenue Requirements Application demonstrated these characteristics of the regulatory environment clearly. The application was approved within three months of initial submission as a result of a negotiated settlement agreement (one of several negotiated settlements that have been achieved since FTS acquired ownership of FBC in 2004). The approved rate increase of 3.5% was relatively close to FBC's updated request of 4%. In December 2009, the British Columbia Utilities Commission's (BCUC) ROE and cost of capital decision resulted in an increase in FBC's ROE from 8.87% in 2009 to 9.9% for 2010. Importantly, the previously approved rate increase was revised to 6% on December 30, 2009 to reflect the impact of this decision, meaning that FBC did not experience any delay in benefiting from the improvement in ROE. One other outcome of the ROE and cost of capital decision was the elimination of the automatic adjustment mechanism that had previously been used to update the allowed ROE. We see this as positive since the adjustment mechanism had been distorted by the compression of Government of Canada Bond yields during the credit crisis and produced lower allowed ROEs whilst corporate risk premiums increased significantly. The BCUC will consider alternative adjustment mechanisms in the next twelve months.

FBC is regulated primarily on a cost of service basis although there are limited performance based rate-making (PBR) provisions in place relative to operating and maintenance (O&M) expenses. To a degree, the regulatory regime mitigates FBC's exposure to forecast risk by allowing the company to forecast costs other than O&M in its annual revenue requirements application and then recover or refund variations between certain forecast and actual revenues and expenses. Under the PBR agreement, FBC has been able to achieve actual ROEs in excess of its allowed ROEs since 2003.

FBC's largest expense item is purchased power; however, certainty of recovery of these costs is high because the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are therefore, effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan and its rate impacts are also reviewed annually during FBC's revenue requirement application. This process of regulatory pre-approval of capital spending reduces the risk of being unable to fully recover capital investments that have already been incurred.

RELATIVELY WEAK FINANCIAL METRICS COMPARED TO PEERS

FBC's credit metrics have demonstrated some improvement since the company was acquired by FTS in 2004. We expect FBC's financial metrics to gradually exhibit further modest improvement over the next few years, reflecting the higher allowed ROE and the growth in rate base, resulting in ratios of CFO pre-W/C to Debt in the range of 13% and Interest Coverage of approximately 3.1x by 2011. Achievement of these metrics is dependent upon, among other things, execution of BCUC-approved capital spending on budget and effective management of forecast risk.

Despite the actual and anticipated improvement in FBC's metrics, the company's ratios remain weak relative to peers. However, we believe that FBC's relatively weak financial profile is offset by the company's location in a supportive regulatory environment.

FBC's ratios are generally consistent with those of Baa3 electric utilities, and remain weaker than its Baa1-rated sister companies, FortisAlberta Inc. (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). For example, FAB and NPI have reported CFO pre-W/C to Debt of approximately 14%-15% while FBC's range has been in the low teens. The marked improvement in FBC's adjusted Debt / Book Capitalization to 59.4% at December 31, 2009 compared to 63.8% at December 31, 2008 reflects the change in Canadian accounting standards, effective January 2009, requiring regulated utilities to recognize future income tax assets and liabilities as well as related regulatory liabilities and assets. This has a ratio impact because deferred taxes are a component in the calculation of capitalization. Moody's notes that the improvement is due to a non-cash accounting change that does not alter FBC's fundamental credit profile although it does enhance the comparability of debt/capitalization metrics between Canadian and US-based peers. Given the relatively small 7.5% weighting of the debt to capitalization metric in the rating methodology, the accounting change does not materially impact the methodology-indicated rating.

CAPITAL EXPENDITURES EXPECTED TO MODERATE RELATIVE TO CASH FLOW

To date, FBC has managed a large capital expenditure program successfully, and regular equity contributions from FTS have enabled it to maintain its deemed 60/40 capital structure. The size of FBC's capital program reflects growth in portions of its service territory as well as the continued need to reinforce FBC's system following a period of under-investment by the previous owner. Between 2005 and 2007, FBC's capex typically represented around 2x its CFO pre-W/C, resulting in relatively large free cash flow deficits. Capital expenditures will remain high in 2010, but are expected to moderate and average roughly 1.2 times CFO pre-W/C over the next five years. We expect that FBC will continue to generate negative free cash flow in the medium-term, but from 2011 these deficits are likely to be at lower levels than in the recent past.

There is a risk that continued elevated capital expenditures, which are expected to necessitate rate increases above the level of inflation, could lead to ratepayer fatigue. However, this risk should be significantly mitigated by the BCUC's review and approval of FBC's periodic capital plans and its annual review of the company's spending plans as part of the annual revenue requirements application process. Once the capital spending plans are approved by the BCUC, we believe that it is relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. We also note that the increase in FBC's rates is consistent with trends across the Province, and in fact FBC's approved rate increase of 6% for 2010 is lower than the 9.26% increase requested by BCH for its service territory. Accordingly, we believe that the greatest risk related to FBC's capital expenditure plans is the company's ability to prudently manage its projects to avoid excessive cost overruns, the full recovery of which might not be permitted by the regulator.

**Liquidity Profile**

FBC's liquidity arrangements are satisfactory. We estimate that FBC will have negative free cash flow of approximately $90 million for the twelve month period to June 30, 2011. The company does not have material debt maturities in this period. With undrawn committed credit facilities of approximately $118 million at March 31, 2010, FBC is able to withstand our standard liquidity stress scenario, which assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months. On this basis, FBC has an estimated buffer of approximately $30 million, not including projected equity contributions from FTS.

On April 30, 2010, FBC announced that it had received all approvals required to amend the terms of its credit facility.

Once amended three-year revolving tranche to will be increased to $100 million with a May 8, 2013 maturity and the 364-day revolving tranche will be reduced to $50 million with a May 5, 2011 maturity. The three-year tranche will continue to be extendible annually for further one-year periods, subject to the agreement of the banks, while the 364-day tranche will continue to have an automatic 6-month term-out in the event that it is not extended.

We consider FBC's access to the financial resources and executive support of its parent, FTS, to be a credit strength. Regardless of the fact that FBC is insulated to a degree from the credit profile of its parent by certain covenants in its credit agreement, FTS has nonetheless consistently demonstrated good management and support of its subsidiaries and the ability to maintain or rebuild good relationships with regulators. While FTS could seek to increase dividends from FBC to support the operations of the parent or sister subsidiaries, the expectation is that dividends will not exceed the level necessary to maintain FBC's 60/40 target capital structure. FTS' liquidity is supported by a $600 million committed syndicated credit facility, maturing in May 2012, which had $547 million of availability at March 31, 2010. We also expect that FTS will continue to contribute capital as needed in order to allow FBC to remain close to its deemed capital structure.

### Rating Outlook

The rating outlook is stable based on our expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened.

### What Could Change the Rating - Up

FBC's rating could be positively impacted if FBC were to be able to demonstrate a sustainable improvement in financial ratios, such as CFO pre-W/C Interest Coverage of approximately of 4.0 times and CFO pre-W/C to Debt above 16%.

### What Could Change the Rating - Down

A downgrade of FBC's rating would likely require a combination of a deterioration of FBC's regulatory framework, ability to earn its allowed return, liquidity and financial profile. This might include sustained weakening of FBC's metrics such as CFO pre-W/C Interest coverage of below 2.7x and CFO pre-W/C to Debt below 10%.

## Rating Factors

### FortisBC Inc

| Regulated Electric and Gas Utilities Rating Methodology | Aaa | Aa | A | Baa | Ba | B |
|---|---|---|---|---|---|---|
| **Factor 1: Regulatory Framework (25%)** | | | X | | | |
| **Factor 2: Ability to Recover Costs and Earn Returns (25%)** | | | X | | | |
| **Factor 3: Diversification (10%)** | | | | | | |
| a) Market Position (5%) | | | | X | | |
| b) Generation and Fuel Diversity (5%) | | X | | | | |
| **Factor 4: Financial Strength, Liquidity & Financial Metrics (40%)** | | | | | | |
| a) Liquidity (10%) | | | | X | | |
| b) CFO pre-WC + Interest / Interest (7.5%) | | | | X | | |
| c) CFO pre-WC / Debt (7.5%) | | | | | X | |
| d) CFO pre-WC - Dividends / Debt (7.5%) | | | | X | | |
| e) Debt / Capitalization or Debt / RAV (7.5%) | | | | | X | |
| **Rating:** | | | | | | |
| a) Methodology Implied Senior Unsecured Rating | | | | **Baa1** | | |
| b) Actual Senior Unsecured Rating | | | | **Baa1** | | |

of the Corporations Act 2001).

MOODY'S INVESTORS SERVICE

**Credit Opinion: FortisBC Inc**

**Global Credit Research - 06 Sep 2011**

*British Columbia, Canada*

## Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Stable |
| Senior Unsecured -Dom Curr | Baa1 |

## Contacts



| Analyst | Phone |
|---|---|
| Allan McLean/Toronto | 416.214.3852 |
| William L. Hess/New York City | 212.553.3837 |



## Key Indicators

[1]**FortisBC Inc**

| | [2]LTM | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|
| (CFO Pre-W/C + Interest) / Interest Expense | 3.2x | 3.0x | 2.9x | 2.8x | 2.7x |
| (CFO Pre-W/C) / Debt | 12.9% | 11.6% | 11.9% | 11.2% | 10.9% |
| (CFO Pre-W/C - Dividends) / Debt | 10.7% | 9.5% | 9.6% | 8.9% | 8.8% |
| Debt / Book Capitalization | 59.7% | 60.0% | 59.4% | 63.8% | 64.4% |

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. [2] LTM = last twelve months to June 30, 2011

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

## Opinion

### Rating Drivers

Low-risk vertically integrated hydro-electric utility

Supportive regulatory environment

Relatively weak financial metrics

Free cash flow deficits have moderated due to rate base and cash flow growth

Sufficient liquidity

### Corporate Profile

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated regulated hydro-electric utility that operates primarily under a cost-of-service regulatory regime. FBC is an indirect, wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

### SUMMARY RATING RATIONALE

The Baa1 senior unsecured rating of FBC reflects the low-risk nature of the utility where over 95% of its operations are regulated and the few unregulated operations it does have are relatively low-risk. The rating also considers FBC's location in a supportive regulatory environment and the limited performance based regulatory regime under which FBC has operated that has allowed it to earn more than its allowed return on equity (ROE) in most years since 2003. These strengths are offset by financial metrics that remain weak relative to those of Baa1-rated peers notwithstanding that FBC's financial metrics have improved modestly in recent years. Over the past five years, FBC's total assets grew by more than 75% driven by utility capital investment. Cash flow from operations before working capital changes (CFO pre-WC) was almost $83 million in 2010 (roughly double the 2005 level) primarily due to rate base growth although a higher allowed ROE of 9.9% in 2010 also contributed. We expect FBC will have smaller free cash flow deficits going forward and less need for parental equity injections. FBC's liquidity resources are sufficient.

**DETAILED RATING CONSIDERATIONS**

REGULATED HYDRO-ELECTRIC UTILITY WITH LIMITED HYDROLOGY RISK

FBC's rating reflects the company's low business risk profile where over 95% of its operations are regulated and its unregulated operations are low-risk in nature. Moody's considers FBC's business risk to be lower than that of other cost-of-service regulated vertically integrated utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments (fuel purchase and electricity sales), a hydro-electric utility's greatest risk is hydrology. Actual water flows can vary significantly from those forecast with significant cash flow repercussions. However, FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement (CPA), which runs until at least 2035. Under the CPA, FBC and others cede scheduling control of their generation facilities to British Columbia Hydro and Power Authority (BCH, Aaa) in exchange for power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. FBC's hydro-electric generation facilities provide about 45% of its annual energy requirement. FBC has power purchase agreements (PPAs) with BCH and Brilliant Power Corporation (BPC, A1, stable) which provide the bulk of the balance of FBC's requirements, representing approximately 18% and 27%, respectively, of its 2010 energy requirements. With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the province of British Columbia.

FBC's largest unregulated asset is the Walden Power Plant, a 16 MW run-of-river hydro-electric project that sells power to BCH under a PPA expiring in 2013. FBC also generates a small amount of revenue by providing operations and management services to embedded utilities and hydro-electric generators.

SUPPORTIVE REGULATORY ENVIRONMENT

FBC's location in British Columbia which enjoys a relatively strong provincial economy (2010 GDP growth of ~4%) and continues to enjoy a supportive regulatory climate, contributes to our view of FBC as a lower risk utility. We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, we consider the regulatory environment in British Columbia to be one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced with minimal regulatory lag.

FBC is regulated primarily on a cost-of-service basis although there have been limited performance based rate-making (PBR) provisions in place relative to operating and maintenance (O&M) expenses. To a degree, the regulatory regime mitigates FBC's exposure to forecast risk by allowing the company to forecast costs other than O&M in its annual revenue requirement application and then recover or refund variations between certain forecast and actual revenues and expenses. Under PBR, FBC has been able to achieve actual ROEs in excess of its allowed ROEs in every year except 2010 since 2003. In 2010, FBC fell just short of achieving its allowed ROE due primarily to unfavourable weather conditions in the first half of the year. FBC's revenue requirement application for 2012 and 2013, filed in June 2011, does not contemplate a continuation of the limited PBR arrangement.

FBC's largest expense item is purchased power; however, certainty of recovery of these costs is high because the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are therefore, effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan's rate impacts are also reviewed during FBC's annual revenue requirement application process. This process of obtaining regulatory pre-approval of capital spending reduces the risk of being unable to fully recover capital investments that have already been incurred.

FINANCIAL METRICS REMAIN WEAK COMPARED TO Baa1-RATED PEERS

FBC's financial metrics have demonstrated modest improvement since the company was acquired by FTS in 2004. We expect FBC's financial metrics to remain relatively stable over the next few years with CFO pre-W/C to Debt in the range of 12% to 13% and Interest Coverage of approximately 3x. Achievement of these metrics is dependent upon, among other things, execution of BCUC-approved capital spending on budget and effective management of forecast risk.

Despite the modest improvement in FBC's metrics, the company's ratios remain weak relative to Baa1-rated peers. However, we believe that FBC's relatively weak financial profile is offset by the company's relatively low business risk and location in an above average supportive regulatory environment.

FBC's ratios are generally consistent with those of Baa3 electric utilities, and remain weaker than its Baa1-rated sister companies, FortisAlberta Inc. (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). For example, FAB and NPI have reported CFO pre-W/C to Debt of approximately 15%-20% while FBC's range has been in the low teens. The marked improvement in FBC's adjusted Debt / Book Capitalization to 59.4% at December 31, 2009 compared to 63.8% at December 31, 2008 reflects the change in Canadian accounting standards, effective January 2009, requiring regulated utilities to recognize future income tax assets and liabilities as well as related regulatory liabilities and assets. This has a ratio impact because deferred taxes are a component in the calculation of capitalization. Moody's notes that the improvement is due to a non-cash accounting change that does not alter FBC's fundamental credit profile although it does enhance the comparability of debt/capitalization metrics between Canadian and US-based peers. Given the relatively small 7.5% weighting of the debt to capitalization metric in the rating methodology, the accounting change does not materially impact the methodology-indicated rating.

CAPITAL EXPENDITURES MORE MANAGEABLE

To date, FBC has successfully managed a large capital expenditure program, and regular equity contributions from FTS have enabled it to maintain its capital structure close to its deemed 60/40 capital structure. FBC's capital program is driven by growth in portions of its service territory as well as the continued need to reinforce its system following a period of under-investment by the previous owner. Between 2005 and 2007, FBC's capex typically represented around 2x its CFO pre-W/C, resulting in relatively large free cash flow deficits. We expect capital investment to be in the range of $100 million to $125 million for the next few years but we expect the ratio of capital investment to CFO pre-WC to fall to roughly 1.1x to 1.2x. We expect that FBC will continue to generate negative free cash flow in the medium-term, but from 2011 onward we expect these deficits to be smaller than those of past years with the result that the need for parental equity injections could be eliminated as early as 2012.

As has been the case since FTS acquired FBC, we expect FBC's capital investments to require rate increases at levels above the rate of inflation. While it has not done so to date, this could eventually lead to ratepayer fatigue. That said, we believe that the risk of ratepayer fatigue is significantly mitigated by the BCUC's review and approval of FBC's periodic capital plans as well as its review of the rate impact of company's spending plans as part of the annual revenue requirement application process. Once the capital spending plans are approved by the BCUC, we believe that it is relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. We also note that the increase in FBC's rates is consistent with trends across the Province. In fact, FBC's requested rate increases of 4% for 2012 and 6.9% for 2013 are lower than the 9.73% increase requested by BCH for its service territory in each of its fiscal years ending March 31, 2012, 2013 and 2014. Accordingly, we believe that the greatest risk related to FBC's capital expenditure plans is the company's ability to prudently manage its projects to avoid excessive cost overruns, the full recovery of which might not be permitted by the regulator.

**Liquidity Profile**

FBC's liquidity arrangements are satisfactory. We estimate that FBC will have negative free cash flow of approximately $40 million for the twelve month period ending June 30, 2012. The company does not have any material debt maturities during this period so it's funding requirement will be similarly sized. With undrawn committed credit facilities of approximately $140 million at June 30, 2011, FBC is able to withstand our standard liquidity stress scenario, which assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months. On this basis, FBC has an estimated buffer of approximately $100 million, not including projected equity contributions from FTS.

FBC maintains a committed syndicated credit agreement which comprises two separate facilities. Facility A is a $100 million three-year revolving facility with a May 7, 2014 maturity. Facility B is a $50 million 364-day revolving facility with a May 3, 2012 maturity. The three-year tranche will continue to be extendible annually for further one-year periods, subject to the agreement of the banks, while the 364-day tranche will continue to have an automatic 6-month term-out in the event that it is not extended. The credit facilities do not include features like a material adverse change clause that would limit access to funds during a period of financial stress. They are, however, subject to a covenant that requires FBC's debt to capitalization ratio not to exceed 75%. At June 30, 2011, FBC was in compliance with this covenant with debt to capitalization of roughly 60%.

**Rating Outlook**

The rating outlook is stable based on our expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its financial metrics are not materially weakened.

**What Could Change the Rating - Up**

FBC's rating could be positively impacted if FBC were to be able to demonstrate a sustainable improvement in financial ratios, such as CFO pre-W/C Interest Coverage of approximately of 4.0 times and CFO pre-W/C to Debt above 16%.

**What Could Change the Rating - Down**

A downgrade of FBC's rating would likely require a combination of a deterioration of FBC's regulatory framework or liquidity and financial profile, or an inability to earn its allowed return. This might include sustained weakening of FBC's metrics such as CFO pre-W/C Interest coverage of below 2.7x and CFO pre-W/C to Debt below 10%.

## Rating Factors

**FortisBC Inc**

| **Regulated Electric and Gas Utilities Industry** [1] | [2]**Current** | | [3]**Moody's 12-18 month Forward View As of 08/30/2011** | |
|---|---|---|---|---|
| **Factor 1: Regulatory Framework (25%)** | **Measure** | **Score** | **Measure** | **Score** |
| a) Regulatory Framework | | A | | A |
| **Factor 2: Ability To Recover Costs And Earn Returns (25%)** | | | | |
| a) Ability To Recover Costs And Earn Returns | | A | | A |
| **Factor 3: Diversification (10%)** | | | | |
| a) Market Position (10%) | | Baa | | Baa |
| b) Generation and Fuel Diversity (0%) | | Aa | | Aa |
| **Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)** | | | | |
| a) Liquidity (10%) | | Baa | | Baa |
| b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%) | 2.9x | Baa3 | 3.0x | Baa3 |
| c) CFO pre-WC / Debt (3 Year Avg) (7.5%) | 11.6% | Ba1 | 12%-13% | Ba1 |
| d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%) | 9.4% | Baa3 | 9%-10% | Baa3 |
| e) Debt/Capitalization (3 Year Avg) (7.5%) | 60.9% | Ba2 | 58%-60% | Ba2 |
| **Rating:** | | | | |
| a) Indicated Rating from Grid | | Baa1 | | Baa1 |
| b) Actual Rating Assigned | | Baa1 | | |

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments [2] Financial ratios reflect three year averages for 2008, 2009 and 2010, Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

Act 2001.

Notwithstanding the foregoing, credit ratings assigned on and after October 1, 2010 by Moody's Japan K.K. ("MJKK") are MJKK's current opinions of the relative future credit risk of entities, credit commitments, or debt or debt-like securities. In such a case, "MIS" in the foregoing statements shall be deemed to be replaced with "MJKK". MJKK is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO.

This credit rating is an opinion as to the creditworthiness or a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be dangerous for retail investors to make any investment decision based on this credit rating. If in doubt you should contact your financial or other professional adviser.

**Summary of FortisBC Inc. (Electric) changes in Credit Ratings from 2002-2012**

| Rating Agency | Report Date | Rating Action | Rating |
|---|---|---|---|
| DBRS | October 2010 | Upgraded | A(low) |
| DBRS | November 2004* | Confirmed | BBB(high) |

*FortisBC's Secured Debentures have been rate BBB(high) since prior to 2002 and an upgrade was received in October 2010. Prior to the Company's first public debt offering in November 2004, there were no ratings on any Unsecured Debentures.

| Rating Agency | Report Date | Rating Action | Rating |
|---|---|---|---|
| Moody's | May 2010 | Upgraded | Baa1 |
| Moody's | June 2007 | Upgraded | Baa2 |
| Moody's | November 2004** | Confirmed | Baa3 |

**FortisBC's initial Moody's debt rating was issued in November 2004, prior to the Company's first public debt offering. In order to make a public debt offering, a company requires two debt ratings and DBRS was already rating the Company's Secured Debentures. All of FortisBC's long-term debt offerings prior to November 2004 had been private placements.

**3. Reports by investment analysts for the utility and corporate parent since 2006, where applicable:**

- There are no equity investment analyst reports for FBC
- See section 3 of FEI's Company Related Documents for equity investment analyst reports for FBC's ultimate parent, Fortis Inc. (FTS)
- Enclosed are debt investment analyst reports for FBC
  - BMO
  - Scotiabank
- See section 3 of FEI's Company Related Documents filing for debt investment analyst reports for FBC's ultimate parent, Fortis Inc. (FTS)

# FortisBC Inc.

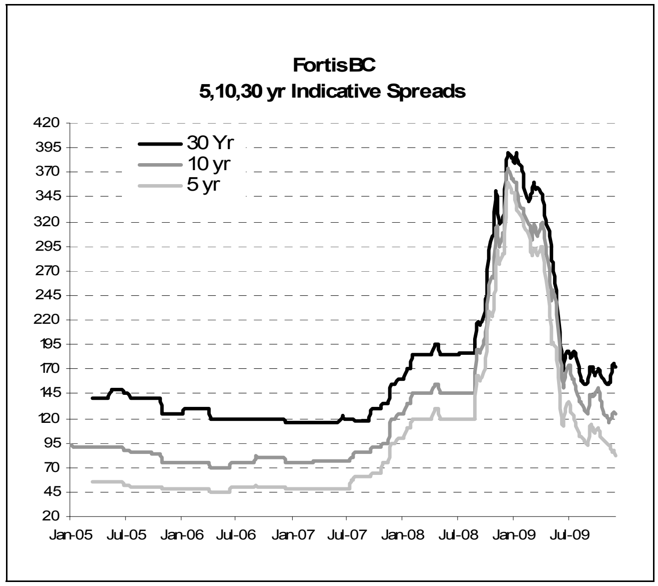
BEN PHAM

## Relative Value

**Recommendation** – We believe the credit spreads of FortisBC will likely tighten over the forecast period. We believe credit support is provided by a stable regulatory regime and the independent structure between the holding company, Fortis Inc., and the operating company, FortisBC. We believe FortisBC will operate as a stand-alone entity and that it will carry out all of the debt financing requirements at the operating company level.

**Sector Value** – We believe FortisBC's indicative credit spreads are attractively valued at current levels. The 5-year, 10-year, and 30-year spread differentials between FortisBC and Hydro One are currently 35, 35, and 29 basis points, respectively.

**Credit Curve** – FortisBC's 10s-30s curve is at roughly 47 basis points, while its 5s-10s is around 43 basis points, suggesting there is some relative value in the middle part of its curve.




Source: BMO Capital Markets.

## Risks

**External** – Severe weather conditions and natural disasters may result in the interruption of electricity service that could have a material adverse effect on the company's operations, cash flows and financial position. The company has limited insurance against storm damage and other natural disasters.

**M&A** – FortisBC's current focus is on rate base growth within its service territory.

**Regulatory** – The utility operations of the company are subject to the regulatory determinations of the British Columbia Utilities Commission, with respect to rates, capital expenditures, and the authorized return on equity.

**Trading Liquidity** – We believe FortisBC exhibits below-average trading liquidity in the Canadian bond market.

**New Issuance** – Cash flow from operating activities will likely not be adequate to meet capital expenditure and dividend requirements over the forecast period. Our estimates assume debt issuances of approximately $100 million in 2010. We expect proceeds of this issue will be used to pay down operating credit facility that has been used to finance the company's capital expenditure program.

**Other** – An extended decline in British Columbia's economy or in the company's service area is likely to reduce electricity demand over time. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth.

## Credit Profile

**Company Financials** – FortisBC reported net earnings of $8.3 million in Q3/09, a $0.3 million decrease over the same period last year. The variance was primarily due to higher year-over-year operating and interest expenses, partially offset by a decrease in income taxes.

During the quarter, FortisBC issued $105 million 6.10% medium term notes due June 2, 2039. The net proceeds from the issue were primarily used to finance capital expenditures and repay bank debt and the $50 million 6.75% unsecured debenture due July 31, 2009. The debt-to-capitalization ratio decreased by approximately 60 bps to 58.5% as at Q3/09 compared to 59.1% as at year-end 2008.

**Company Fundamentals** – FortisBC expects the total number of customer accounts to increase by 1.5% in 2010, lower than the five-year average annual growth of 2.3%, but consistent with the 20-year average of 1.4%.

**Capex** – On February 27, 2009, the British Columbia Utilities Commission approved FortisBC's 2009–2010 Capital Expenditure Plan. The Commission approved capital expenditures (net of customer contributions) of $110.0 million in 2009 and $157.1 million in 2010. The primary focus of the capital program continues to be the improvement of FortisBC's transmission and distribution systems in order to meet the growth in demand and need for increased reliability in the company's service territory.

**Credit Ratings** – On June 5, 2009, DBRS confirmed FortisBC's BBB (high) rating with a Stable Trend. The rating reflects FortisBC's low business risk stemming from the regulated nature of its operations and supportive regulatory environment, its integrated operations, which include a secure low-cost hydro-based power supply portfolio, a diversified customer base and its stable credit metrics.

On January 28, 2009, Moody's affirmed FortisBC's Baa2 rating with a Stable Outlook. The ratings reflect the low-risk nature of the utility where 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low risk. The agency also cited constraints on the rating including weak credit metrics, weak liquidity arrangements, and continued reliance on net equity injections over the next several years.

| DBRS | S&P | Moody's |
|---|---|---|
| BBB (high)<br>Stable | Not Rated | Baa2<br>Stable |

**Company Description** – FortisBC is an integrated, regulated utility that generates, transmits and distributes electricity to over 158,000 customers in south-central British Columbia. Approximately 65% of customers are served directly by FortisBC, while the remainder are supplied through wholesale power purchase agreements with six municipal utilities. Key utility assets include four hydroelectric generation facilities with a combined capacity of 223 MW and over 7,000 kilometres of transmission and distribution power lines. The company meets about 45% of its energy requirements through its own generating units, with the remainder met through power purchase agreements. FortisBC is regulated by the British Columbia Utilities Commission. The company is an indirect, wholly-owned subsidiary of Fortis Inc.

*Website: www.fortisbc.com*

**Corporate Developments** – On October 1, 2009, FortisBC filed a preliminary 2010 revenue requirement application. The company is requesting a rate increase of 4.6% and the application specifies: (i) mid-year rate bases of $872.4 million in 2009 and $975.8 million in 2010; (ii) depreciation for rate-making purposes of $37.4 million in 2009 and $42.0 million in 2010; (iii) capital expenditures (net of customer contributions) for rate-making purposes of $110.0 million in 2009 and $157.1 million in 2010; (iv) deemed equity of 40% in 2009 and 2010; and (v) an allowed return on equity of 8.78% in 2010 vs. an allowed return on equity of 8.87% in 2009.

We note that on May 15, 2009, Terasen Utilities (collectively Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.) applied to the Commission for a cost of return on equity and capital structure review. In the application, Terasen Utilities requested that the Commission eliminate the use of the ROE automatic adjustment mechanism, that the ROE for Terasen Gas Inc. be set at 11.0%, effective July 1, 2009, and that this ROE be set as the benchmark generic ROE for a low-risk utility. The result of the Terasen Utilities application will directly effect FortisBC's allowed ROE as Terasen Gas is the benchmark low-risk utility for purposes of applying FortisBC's risk premium (currently at 40 bps above the benchmark generic ROE).

On February 27, 2009, the British Columbia Utilities Commission approved FortisBC's 2009–2010 Capital Expenditure Plan. The Commission approved capital expenditures (net of customer contributions) of $110.0 million in 2009 and $157.1 million in 2010. The primary focus of the capital program continues to be the improvement of FortisBC's transmission and distribution systems in order to meet the growth in demand and need for increased reliability in the company's service territory**.**

**Recent Results –** FortisBC reported net earnings of $8.3 million in Q3/09, a $0.3 million decrease over the same period last year. The variance was primarily due to higher operating and interest expenses, partially offset by a decrease in income taxes.

Capital expenditures for the first nine months of 2009 amounted to approximately $74.6 million, net of $4.4 million in customer contributions. Significant capital projects for the first nine months of 2009 are as follows: $7.1 million for the Black Mountain Substation Project, $7.1 million for the Okanagan Transmission Reinforcement Project; $6.9 million relating to new distribution line extensions for customers; $6.4 million for the Generation Unit Life Extension program; $3.4 million for the Ellison Substation Project; and $2.3 million for the Benvoulin Substation Project.

During the quarter, FortisBC issued $105 million 6.10% medium term notes due June 2, 2039. The net proceeds of the issue was primarily used to finance capital expenditures and repay bank debt and the $50 million 6.75% unsecured debenture due July 31, 2009. The debt-to-capitalization ratio decreased by approximately 60 bps to 58.5% as at Q3/09 compared to 59.1% as at year-end 2008.

**Capitalization and Liquidity –** FortisBC had $548.7 million of long-term debt outstanding at September 30, 2009. Fortis BC's bank operating facilities comprise of a $50 million three-year revolving facility maturing on May 9, 2012 and a $100 million, 364-day revolving facility maturing on May 6, 2010. At quarter-end, FortisBC had $148 million available on these facilities. FortisBC also has $195 million of medium term notes available under its $300 million shelf prospectus that expires on June 22, 2011. On June 2, 2009, FortisBC issued $105 million 6.10% medium term notes due June 2, 2039. The net proceeds from the issue were primarily used to finance capital expenditures and repay bank debt and the $50 million 6.75% unsecured debenture due July 31, 2009. We believe the company will likely finance its capital expenditure program with short-term debt in the near term, which it will then likely term out in the long term. Debt to capitalization ratio decreased by approximately 60 bps to 58.5% as at Q3/09 compared to 59.1% as at year-end 2008.

**Credit Ratings** – On June 5, 2009, DBRS confirmed FortisBC's BBB (high) rating with a Stable Trend. The ratings reflect FortisBC's low business risk stemming from the regulated nature of its operations and supportive regulatory environment, its integrated operations, which include a secure low-cost hydro-based power supply portfolio, a diversified customer base, and its stable credit metrics. Although DBRS expects continued free cash flow deficits over the near to medium term due to an elevated capital expenditure program ($700 million over the next five year), it believes the company's key credit ratios will remain stable and adequate for the current credit rating category.

On January 28, 2009, Moody's affirmed FortisBC's Baa2 rating with a Stable Outlook. The ratings reflect the low-risk nature of the utility where 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low risk. The agency also went on to note the company's supportive regulatory environment with a limited performance based regulatory regime that enables the utility to consistently earn above its allowed return on equity and recover its costs in a timely manner. The agency also cited constraints on the rating including the company's weak credit metrics, weak liquidity arrangements, and continued reliance on net equity injections over the next several years.

# FortisBC Inc.

## Maturity Schedule

| Company | Coupon | Maturity | Amount ($mm) | Instrument | Issue Date | Issue Spread | Callable | CUSIP | Outstanding ($mm) |
|---|---|---|---|---|---|---|---|---|---|
| FortisBC Inc. | 9.65% | 16-Oct-12 | $15 | Secured Debenture | 16-Oct-92 | NA | Make Whole (+40.0 bps) | NA | $15 |
| FortisBC Inc. | 9.44% | 31-Oct-13 | $5 | WPP Mortgage | NA | NA | NA | NA | $4 |
| FortisBC Inc. | 5.48% | 28-Nov-14 | $140 | Unsecured Debenture | 30-Nov-04 | 97.0 bps | Make Whole ( +24 bps) | 34957UAA3 | $140 |
| FortisBC Inc. | 8.77% | 01-Feb-16 | $25 | Unsecured Debenture | 01-Mar-96 | NA | Make Whole (+35.0 bps) | NA | $25 |
| FortisBC Inc. | 7.81% | 01-Dec-21 | $25 | Unsecured Debenture | 01-Jun-97 | NA | Make Whole (+25.0 bps) | NA | $25 |
| FortisBC Inc. | 8.80% | 28-Aug-23 | $25 | Secured Debenture | 30-Nov-93 | NA | Make Whole (+40.0 bps) | 95358DAA7 | $25 |
| FortisBC Inc. | 5.60% | 09-Nov-35 | $100 | Unsecured Debenture | 10-Nov-05 | 120.0 bps | Make Whole ( +30 bps) | 34957UAB1 | $100 |
| FortisBC Inc. | 6.10% | 02-Jun-39 | $105 | Medium term note | 02-Jun-09 | 195.0 bps | Make Whole (+49 bps) | 34958ZAA1 | $105 |
| FortisBC Inc. | 5.90% | 04-Jul-47 | $105 | Unsecured Debenture | 04-Jul-07 | 125.0 bps | Make Whole ( +31 bps) | 34957UAC9 | $105 |

Source: Bloomberg

## Ownership Structure

100% - Fortis Inc.

## Credit Facilities ($mm)

| Company | Facility Size | Amount Available Q3/09 | Amount Available Q2/09 | Maturity | Type |
|---|---|---|---|---|---|
| FortisBC[1] | $100.0 | | | 06-May-10 | 364-Day Revolving Term Facility |
| FortisBC | $50.0 | | | 09-May-12 | 3-Year Revolving Facility |
| FortisBC | $10.0 | | | | Demand overdraft Facility |
| | | $158.0 | $157.0 | | |

Source: Company Reports

## Corp. Lease Schedule (12/31/2008)

| ($mm) Year | Capital Lease Payments | Operating Lease Payments | Lease Receipts |
|---|---|---|---|
| 2009 | 2.552 | 1.959 | |
| 2010 | 2.552 | 1.959 | |
| 2011 | 2.552 | 1.959 | |
| 2012 | 2.552 | 1.959 | |
| 2013 | 2.552 | 1.254 | |
| Thereafter | 63.03 | 13.103 | |

Source: Company Reports

## Shelf Prospectus

| Company | Type | Amount | Remaining | Date | Expiry | Instruments |
|---|---|---|---|---|---|---|
| FortisBC Inc. | Shelf | $300 | $195 | 22-May-09 | 22-Jun-11 | Medium Term Notes |

Source: SEDAR

## Pension Summary

| | Pension Benefit Plans FY2008 ($mm) | Pension Benefit Plans FY2007 ($mm) | Other Benefit Plans FY2008 ($mm) | Other Benefit Plans FY2007 ($mm) |
|---|---|---|---|---|
| Accrued Benefit Obligation | 117.3 | 121.7 | 15.4 | 16.7 |
| Plan Assets | 95.5 | 105.0 | 0.0 | 0.0 |
| Funded Status | (21.8) | (16.7) | (15.4) | (16.7) |
| Accrued Benefit Asset (Liability) Net of Valuation Allowance | 8.6 | 6.7 | (10.5) | (8.7) |
| Discount Rate (benefit cost) | 5.25% | 5.00% | 5.25% | 5.00% |
| Expected Long-term Rate of of Return on Assets | 7.00% | 7.00% | NA | NA |
| Rate of Future Increase in Compensation | 3.50% | 3.50% | 3.50% | 3.50% |

Source: Company Reports

## Historical Ratings
## Issuer Credit Rating – FortisBC Inc.

| DBRS Rating | DBRS Trend | DBRS Date | S&P Rating | S&P Trend | S&P Date | Moody's Rating | Moody's Trend | Moody's Date |
|---|---|---|---|---|---|---|---|---|
| BBB (high) | Stable | 18-Nov-04 | Not Rated | | | Baa2 | Stable | 21-Jun-07 |
| BBB (high) | Under Review - Developing | 16-Sep-03 | | | | Baa3 | UR-Pos | 18-Jun-07 |
| BBB (high) | Stable | 13-May-03 | | | | Baa3 | Stable | 16-Nov-04 |
| BBB (high) | Under Review - Negative | 28-Mar-03 | | | | | | |
| BBB (high) | Stable | 30-Dec-98 | | | | | | |

Source: DBRS, S&P, Moody's

## FortisBC Inc.

| | 2005 | 2006 | 2007 | 2008 | LTM Q3/09 |
|---|---|---|---|---|---|
| EBITDA | 68.7 | 84.1 | 93.8 | 101.5 | 107.4 |
| EBIT | 49.8 | 57.2 | 62.7 | 67.3 | 70.8 |
| Net Earnings | 23.5 | 26.5 | 30.1 | 32.7 | 35.0 |
| Funds from Operations | 40.8 | 56.1 | 60.4 | 65.1 | 72.2 |
| Free Cash Flow | (75.2) | (55.2) | (85.6) | (53.6) | (50.5) |
| Capital Expenditures (excluding acquisitions) | 108.0 | 101.1 | 134.2 | 105.3 | 108.7 |
| Dividends | 8.0 | 10.2 | 11.8 | 13.4 | 14.0 |
| **Balance Sheet ($mm)** | | | | | |
| Long-term Debt (including current portion) | 392.4 | 438.1 | 494.1 | 527.3 | 548.7 |
| Shareholders' Equity | 257.5 | 297.7 | 330.9 | 365.2 | 388.5 |
| **Total Capitalization** | **649.9** | **735.7** | **825.0** | **892.5** | **937.3** |
| Long-term Debt (including current portion) | 60.4% | 59.5% | 59.9% | 59.1% | 58.5% |
| Shareholders' Equity | 39.6% | 40.5% | 40.1% | 40.9% | 41.5% |
| **Total Capitalization** | **100.0%** | **100.0%** | **100.0%** | **100.0%** | **100.0%** |
| **Key Ratios** | | | | | |
| EBITDA Interest Coverage | 3.5x | 3.4x | 3.4x | 3.5x | 3.4x |
| EBIT Interest Coverage | 2.5x | 2.3x | 2.3x | 2.3x | 2.2x |
| Total Debt/EBITDA | 5.7x | 5.2x | 5.3x | 5.2x | 5.1x |
| Total Debt/Capital | 60.4% | 59.5% | 59.9% | 59.1% | 58.5% |
| Funds from Operations/Total Debt | 10.4% | 12.8% | 12.2% | 12.3% | 13.2% |
| **Key Statistics** | | | | | |
| Average Rate Base ($millions) | $586.3 | $675.9 | $747.2 | $822.8 | na |
| Growth Rate | | 15.29% | 10.55% | 10.12% | na |
| Deemed Equity | 40.00% | 40.00% | 40.00% | 40.00% | na |
| Allowed Return on Equity | 9.43% | 9.20% | 8.77% | 9.02% | na |

Source: Company Reports, BMO Capital Markets

**Analyst's Certification**

I, Benjamin Pham, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

**General Disclosure**

The information and opinions in this report were prepared by both BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., collectively ("BMO NB") and BMO Capital Markets Limited (U.K.), ("BMO CM Ltd"). BMO NB and BMO CM Ltd. are not subject to U.S. rules with regard to the preparation of research reports and the independence of analysts. "BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO NB in Canada, BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Capital Markets Ltd. and BMO Capital Markets Corp. are affiliates of BMO NB. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO NB research. A significant lending relationship may exist between BMO Financial Group and certain of the issuers mentioned herein. The opinions, estimates and projections contained in this report are those of BMO NB and BMO CM Ltd. as of the date of this report and are subject to change without notice. BMO NB and BMO CM Ltd. endeavour to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO NB and BMO CM Ltd. make no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO NB, BMO CM Ltd or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. The research analyst and/or associates who prepared this report are compensated based upon (among other factors) the overall profitability of BMO NB, BMO CM Ltd. and its affiliates, which includes the overall profitability of investment banking services. BMO NB, BMO CM Ltd., or its affiliates expect to receive or will seek compensation for investment banking services within the next 3 months from all issuers covered by BMO NB. BMO NB, BMO CM Ltd. or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO NB, BMO CM Ltd. or its affiliates, officers, directors or employees may have a long or short position in the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO NB, BMO Capital Markets Ltd., BMO Capital Markets Corp., Bank of Montreal or their affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Distribution of Ratings (Dec. 3, 2009)**

| Rating Category | BMO Rating | BMO Universe | BMO I.B. Clients * | Starmine Universe ** |
|---|---|---|---|---|
| Buy | Outperform | 40% | 50% | 50% |
| Hold | Market Perform | 51% | 46% | 43% |
| Sell | Underperform | 9% | 4% | 7% |

* Reflects rating distribution of all companies where BMO Capital Markets has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

**Ratings Key**

We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

**Dissemination of Research**

Our research publications are available via our web site http://bmocapitalmarkets.com. Institutional clients may also receive our research via FIRST CALL Research Direct and Reuters. All of our research is made widely available at the same time to all BMO NB, BMO Capital Markets Ltd., BMO Capital Markets Corp. and BMO Nesbitt Burns Securities Ltd. client groups entitled to our research. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**

TO U.S. RESIDENTS: HNC and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO Nesbitt Burns, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through HNC and/or BMO Nesbitt Burns Securities Ltd.A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at:
http://research-ca.bmocapitalmarkets.com/conflict_statement_public.asp

**Additional Matters**

TO U.S. RESIDENTS: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

TO U.K. RESIDENTS: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the “Order”) or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as “relevant persons”). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

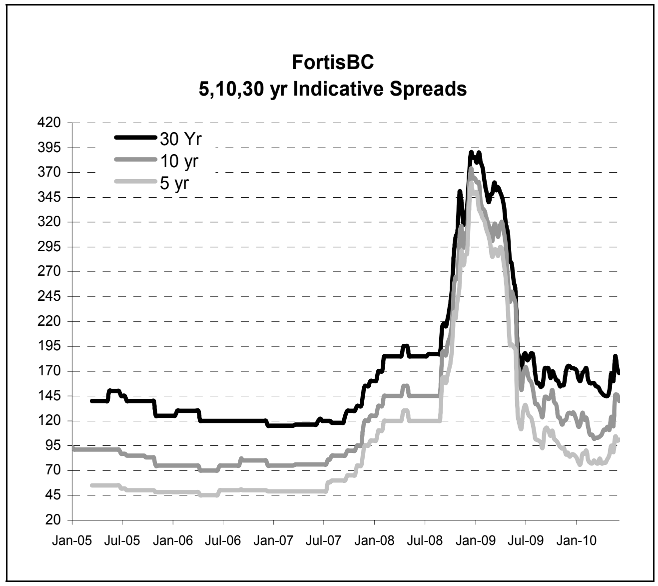
BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée/Ltd. are Members of CIPF. BMO Capital Markets Corp. and BMO Nesbitt Burns Securities Ltd. are Members of SIPC.

## Relative Value

**Recommendation –** We believe the credit spreads of FortisBC will likely tighten over the forecast period. We believe credit support is provided by a stable regulatory regime and the independent structure between the holding company, Fortis Inc., and the operating company, FortisBC. We believe FortisBC will operate as a stand-alone entity and that it will carry out all of the debt financing requirements at the operating company level.

**Sector Value** – We believe FortisBC's indicative credit spreads are attractively valued at current levels. The 5-year, 10-year, and 30-year spread differentials between FortisBC and Hydro One are currently 11, 11, and 10 basis points, respectively.

**Credit Curve** – FortisBC's 10s-30s curve is at roughly 29 basis points, while its 5s-10s is around 34 basis points, suggesting there is some relative value in the middle part of its curve.




Source: BMO Capital Markets

## Risks

**External –** Severe weather conditions and natural disasters may result in the interruption of electricity service that could have a material adverse effect on the company's operations, cash flows and financial position. The company has limited insurance against storm damage and other natural disasters.

**M&A –** FortisBC's current focus is on rate base growth within its service territory.

**Regulatory –** The utility operations of the company are subject to the regulatory determinations of the British Columbia Utilities Commission, with respect to rates, capital expenditures, and the authorized return on equity.

**Trading Liquidity –** We believe FortisBC exhibits below-average trading liquidity in the Canadian bond market.

**New Issuance –** Cash flow from operating activities will likely not be adequate to meet capital expenditure and dividend requirements over the forecast period. Our estimates assume debt issuances of approximately $100 million in 2010. We expect proceeds of this issue will be used to pay down operating credit facilities that have been used to finance the company's capital expenditure program.

**Other –** An extended decline in British Columbia's economy or in the company's service area is likely to reduce electricity demand over time. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth.

## Credit Profile

**Company Financials –** FortisBC reported net earnings of $13.3 million in Q1/10, a $0.1 million increase over the same period last year. The variance was primarily due to lower year-over-year power purchases and income taxes and higher incentive adjustments, partially offset by an increase in interest and depreciation expenses.

FortisBC had $563.2 million of long-term debt outstanding at March 31, 2010. FortisBC's debt to capitalization ratio decreased by approximately 80 bps to 58.4% as at Q1/10 compared to 59.2% as at year-end 2009. FortisBC's authorized bank credit facilities of $160 million is comprised of a $150 million (Facility A: $50 million to mature May 9, 2012; Facility B: $100 million matured May 6, 2010) operating credit facility and a $10 million demand overdraft facility. At the end of Q1/10, FortisBC had $127.8 million available on these facilities. During Q1/10, FortisBC received consent from lenders to extend the Facility A maturity date to May 8, 2013 and increase size by $50 million, and to extend the Facility B maturity date to May 5, 2011 and decrease size by $50 million. FortisBC also has $195 million of medium term notes available under its $300 million shelf prospectus that expires on June 22, 2011.

**Company Fundamentals** – FortisBC expects the total number of customer accounts to increase by 1.5% in 2010, lower than the five-year average annual growth of 2.3%, but consistent with the 20-year average of 1.4%.

**Capex** – FortisBC has forecast capital expenditures of $156.0 million, net of customer contributions for 2010.

**Credit Ratings** – On May 6, 2010, Moody's upgraded FortisBC to Baa1 from Baa2. The outlook is Stable. The rating agency attributed the upgrade to FortisBC's significantly greater liquidity and the expectation for its financial profile to show modest improvement over the next few years. Moody's also cited FortisBC's growing rate base and cash flows that are expected to reduce the size of its free cash flow deficits and its need for parental equity injections to support future capital spending plans. The moderation in capital spending is expected by Moody's to contribute to a modest improvement in FortisBC's credit metrics as the company will have less capital employed that is not generating cash flows.

| DBRS | S&P | Moody's |
|---|---|---|
| BBB (high)<br>Stable | Not Rated | Baa1<br>Stable |

**Disclosures:** 5, 6C

# FortisBC Inc.

## Maturity Schedule

| Company | Coupon | Maturity | Amount ($mm) | Instrument | Issue Date | Issue Spread | Callable | CUSIP | Outstanding ($mm) |
|---|---|---|---|---|---|---|---|---|---|
| FortisBC Inc. | 9.65% | 16-Oct-12 | $15 | Secured Debenture | 16-Oct-92 | NA | Make Whole (+ 40.0 bps) | NA | $15 |
| FortisBC Inc. | 9.44% | 31-Oct-13 | $5 | WPP Mortgage | NA | NA | NA | NA | $4 |
| FortisBC Inc. | 5.48% | 28-Nov-14 | $140 | Unsecured Debenture | 30-Nov-04 | 97.0 bps | Make Whole ( + 24 bps) | 34957UAA3 | $140 |
| FortisBC Inc. | 8.77% | 01-Feb-16 | $25 | Unsecured Debenture | 01-Mar-96 | NA | Make Whole (+ 35.0 bps) | NA | $25 |
| FortisBC Inc. | 7.81% | 01-Dec-21 | $25 | Unsecured Debenture | 01-Jun-97 | NA | Make Whole (+ 25.0 bps) | NA | $25 |
| FortisBC Inc. | 8.80% | 28-Aug-23 | $25 | Secured Debenture | 30-Nov-93 | NA | Make Whole (+ 40.0 bps) | 95358DAA7 | $25 |
| FortisBC Inc. | 5.60% | 09-Nov-35 | $100 | Unsecured Debenture | 10-Nov-05 | 120.0 bps | Make Whole ( + 30 bps) | 34957UAB1 | $100 |
| FortisBC Inc. | 6.10% | 02-Jun-39 | $105 | Medium term note | 02-Jun-09 | 195.0 bps | Make Whole (+ 49 bps) | 34958ZAA1 | $105 |
| FortisBC Inc. | 5.90% | 04-Jul-47 | $105 | Unsecured Debenture | 04-Jul-07 | 125.0 bps | Make Whole ( + 31 bps) | 34957UAC9 | $105 |

Source: Bloomberg, FP Bonds

## Ownership Structure

100% - Fortis Inc.

## Credit Facilities ($mm)

| Company | Facility Size | Amount Available Q1/10 | Amount Available Q4/09 | Maturity | Type |
|---|---|---|---|---|---|
| FortisBC | $100.0 | | | 06-May-10 | 364-Day Revolving Term Facility |
| FortisBC | $50.0 | | | 09-May-12 | 3-Year Revolving Facility |
| FortisBC | $10.0 | | | | Demand Overdraft Facility |
| | | $127.8 | $122.2 | | |

Source: Company Reports

## Corp. Lease Schedule (12/31/2009)

| ($mm) Year | Operating Lease Payments |
|---|---|
| 2010 | 1.959 |
| 2011 | 1.959 |
| 2012 | 1.959 |
| 2013 | 1.245 |
| 2014 | 1.344 |
| Thereafter | 11.758 |

Source: Company Reports

## Shelf Prospectus

| Company | Type | Amount | Remaining | Date | Expiry | Instruments |
|---|---|---|---|---|---|---|
| FortisBC Inc. | Shelf | $300 | $195 | 22-May-09 | 22-Jun-11 | Medium Term Notes |

Source: SEDAR

## Pension Summary

| | Pension Benefit Plans FY2009 ($mm) | Pension Benefit Plans FY2008 ($mm) | Other Benefit Plans FY2009 ($mm) | Other Benefit Plans FY2008 ($mm) |
|---|---|---|---|---|
| Accrued Benefit Obligation | 126.7 | 117.3 | 17.2 | 15.4 |
| Plan Assets | 99.7 | 95.5 | 0.0 | 0.0 |
| Funded Status | (27.0) | (21.8) | (17.2) | (15.4) |
| Accrued Benefit Asset (Liability) Net of Valuation Allowance | 8.9 | 8.6 | (12.0) | (10.5) |
| Discount Rate (benefit cost) | 6.00% | 5.25% | 6.00% | 5.25% |
| Expected Long-term Rate of of Return on Assets | 7.00% | 7.00% | NA | NA |
| Rate of Future Increase in Compensation | 3.50% | 3.50% | 3.50% | 3.50% |

Source: Company Reports

## Historical Ratings
### Issuer Credit Rating – FortisBC Inc.

| DBRS Rating | DBRS Trend | DBRS Date | S&P Rating | S&P Trend | S&P Date | Moody's Rating | Moody's Trend | Moody's Date |
|---|---|---|---|---|---|---|---|---|
| BBB (high) | Stable | 18-Nov-04 | Not Rated | | | Baa1 | Stable | 06-May-10 |
| BBB (high) | Under Review - Developing | 16-Sep-03 | | | | Baa2 | Stable | 21-Jun-07 |
| BBB (high) | Stable | 13-May-03 | | | | Baa3 | UR-Pos | 18-Jun-07 |
| BBB (high) | Under Review - Negative | 28-Mar-03 | | | | Baa3 | Stable | 16-Nov-04 |
| BBB (high) | Stable | 30-Dec-98 | | | | | | |

Source: DBRS, S&P, Moody's

## IMPORTANT DISCLOSURES

**Analyst's Certification**

I, Benjamin Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.

**Company Specific Disclosure**

Disclosure 5: BMO Capital Markets or an affiliate received compensation for products or services other than investment banking services within the past 12 months.

Disclosure 6: This issuer is a client (or was a client) of BMO NB, BMO Capital Markets Corp., BMO CM Ltd. or an affiliate within the past 12 months: Non-Securities Related Services.

**Distribution of Ratings (June 30, 2010)**

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 37.1% | 13.7% | 43.6% | 40.9% | 51.0% | 54.4% |
| Hold | Market Perform | 59.3% | 10.4% | 52.7% | 54.8% | 45.4% | 40.2% |
| Sell | Underperform | 3.6% | 11.8% | 3.6% | 4.3% | 3.6% | 5.4% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.

** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.

*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.

**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.

***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**

We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

**Other Important Disclosures**

For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Company_Disclosure_Public.asp or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**

http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**

Our research publications are available via our web site http://bmocapitalmarkets.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**
A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Conflict_Statement_Public.asp.

**General Disclaimer**
"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**
To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

**ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST**

BMO Financial Group (NYSE, TSX: BMO) is an integrated financial services provider offering a range of retail banking, wealth management, and investment and corporate banking products. BMO serves Canadian retail clients through BMO Bank of Montreal and BMO Nesbitt Burns. In the United States, retail clients are served through Harris N.A. Investment and corporate banking services are provided in Canada and the US through BMO Capital Markets.

BMO Capital Markets is a trade name used by BMO Financial Group for the wholesale banking businesses of Bank of Montreal, Harris N.A. and BMO Ireland Plc, and the institutional broker dealer businesses of BMO Capital Markets Corp. (Member SIPC), BMO Nesbitt Burns Trading Corp. and BMO Capital Markets GKST Inc. (Member SIPC) in the U.S., BMO Nesbitt Burns Inc. (Member CIPF) in Canada, Europe and Asia, BMO Nesbitt Burns Securities Limited (U.S. registered and member of FINRA), and BMO Nesbitt Burns Ltée/Ltd. (Member CIPF) in Canada, and BMO Capital Markets Limited in Europe and Australia. "Nesbitt Burns" is a registered trademark of BMO Nesbitt Burns Corporation Limited, used under license. "BMO Capital Markets" is a trademark of Bank of Montreal, used under license. "BMO (M-Bar roundel symbol)" is a registered trademark of Bank of Montreal, used under license.



A member of BMO Financial Group

# FortisBC

**October 4, 2010**
Brief Research Note

**Ben Pham, CFA**
(416) 359-4061
ben.pham@bmo.com
Assoc: Ewa Bzorek, CA

## DBRS Upgrades to A (low) from BBB (high)

### Impact

Positive

### Details & Analysis

On October 1, DBRS upgraded FortisBC to A (low) from BBB (high). The trend is stable. The agency attributed the upgrade to the company's increased size and scale, supportive regulatory environment, solid project execution, strong parental support, and a demonstrated ability to maintain stable credit metrics over the past five years, despite the continued capex-driven free cash flow deficits. Over the next few years, DBRS expects FortisBC's key credit metrics to improve modestly due to the combination of recent positive regulatory decisions and rate base additions. The agency also cited that the utility has exhibited growth that is considered strong for a regulated utility, with the rate base growing by roughly 10% per annum over the past five years. FortisBC's increased size, with total assets of $1.2 billion, should provide it with improved economies of scale, operating efficiencies, and access to capital. We are not surprised by the rating action and agree with the agency's assessment and further note that DBRS' revised rating of FortisBC is once again one-notch higher than Moody's. Moody's had upgraded FortisBC to Baa1 from Baa2 on May 6. We maintain our market weight recommendation on a 12-month relative basis, but hold a positive bias long-term given improving credit fundamentals.

### Senior Unsecured Debt Ratings

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not Rated | Baa1 |
| Stable | | Stable |

**This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered as a research analyst under FINRA rules. For disclosure statements, including the Analyst's Certification, please refer to pages 2 to 4.**

**IMPORTANT DISCLOSURES**

**Analyst's Certification**
I, Ben Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.

**Company Specific Disclosures**
Disclosure 5: BMO Capital Markets or an affiliate received compensation for products or services other than investment banking services within the past 12 months.
Disclosure 6: This issuer is a client (or was a client) of BMO NB, BMO Capital Markets Corp., BMO CM Ltd. or an affiliate within the past 12 months: Non-Securities Related Services.

**Distribution of Ratings (June 30, 2010)**

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 37.1% | 13.7% | 43.6% | 40.9% | 51.0% | 54.4% |
| Hold | Market Perform | 59.3% | 10.4% | 52.7% | 54.8% | 45.4% | 40.2% |
| Sell | Underperform | 3.6% | 11.8% | 3.6% | 4.3% | 3.6% | 5.4% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.
** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.
*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.
**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.
***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**
We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

**Other Important Disclosures**
For Important Disclosures on the stocks discussed in this report, please go to http://research-ca.bmocm.com/Company_Disclosure_Public.asp or http://research-us.bmocm.com/company_Disclosure_Public.asp or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**
http://research-us.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**
Our research publications are available via our web site http://bmocapitalmarkets.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and

TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**
A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://research-ca.bmocapitalmarkets.com/Conflict_Statement_Public.asp or http://research-us.bmocapitalmarkets.com/Conflict_Statement_Public.asp.

**General Disclaimer**
"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**
To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

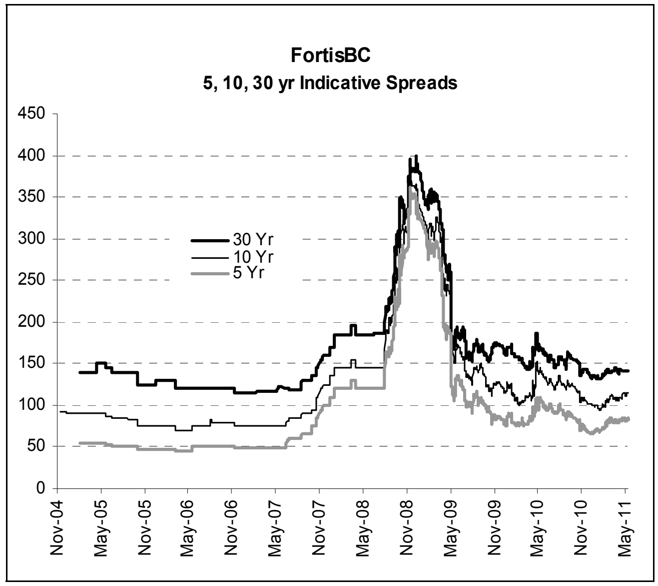
To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

## Relative Value

**Recommendation** – We are maintaining our market-weight recommendation on a 12-month relative basis, but hold a positive bias long-term given improving credit fundamentals. We believe credit support is provided by a stable regulatory regime and the independent structure between the holding company, Fortis Inc., and the operating company, FortisBC. We believe FortisBC will operate as a stand-alone entity and that it will carry out all of the debt financing requirements at the operating company level.

**Sector Value** – We believe FortisBC's indicative credit spreads are reasonably valued at current levels. The 5-year, 10-year and 30-year spread differentials between FortisBC and Hydro One are currently 12 bps, 14 bps and 4 bps, respectively.

**Credit Curve** – FortisBC's 10s-30s curve is at roughly 28 bps, while its 5s-10s is around 31 bps, suggesting there is some relative value in the middle part of its curve.




Source: BMO Capital Markets

## Risks

**External** – Severe weather conditions and natural disasters may result in the interruption of electricity service, which could have a material adverse effect on the company's operations, cash flows and financial position. The company has limited insurance against storm damage and other natural disasters.

**M&A** – FortisBC's current focus is on rate base growth within its service territory.

**Regulatory** – The utility operations of the company are subject to the regulatory determinations of the British Columbia Utilities Commission, with respect to rates, capital expenditures and the authorized return on equity.

**Trading Liquidity** – We believe FortisBC exhibits below-average trading liquidity in the Canadian bond market.

**New Issuance** – Cash flow from operating activities will likely not be adequate to meet capital expenditure and dividend requirements over the forecast period. Our estimates assume debt issuances of approximately $100 million in 2011. We expect proceeds of this issue will be used to pay down operating credit facilities that have been used to finance the company's capital expenditure program.

**Other** – An extended decline in British Columbia's economy or in the company's service area is likely to reduce electricity demand over time. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth.

## Credit Profile

**Company Financials** – FortisBC reported net earnings of $18.5 million in Q1/11, a $5.2 million increase over the same period last year. The variance was primarily due to a rate increase, infrastructure growth and higher regulated ROE.

FortisBC had $636.7 million of long-term debt outstanding at March 31, 2011. FortisBC's debt to capitalization ratio of 58.7% as at Q1/11 decreased 84 bps from 59.5% as at year-end 2010. FortisBC's authorized bank credit facilities of $160 million comprises a $150 million (Facility A: $100 million to mature May 7, 2014; Facility B: $50 million maturing May 3, 2012) operating credit facility and a $10 million demand overdraft facility. At the end of Q1/11, FortisBC had $160 million available on these facilities. FortisBC also has $95 million of medium term notes available under its $300 million shelf prospectus that expires on June 22, 2011.

**Company Fundamentals** – FortisBC expects the total number of customer accounts to increase 2.3% over the next five years, well above the 20 year average of 1.4%.

**Capex** – FortisBC has forecast capital expenditures of $90.4 million, net of customer contributions for 2011. Year-to-date 2011, FortisBC has spent $21.5 million. Significant capital projects include $6.5 million for the Okanagan Transmission Reinforcement Project, $3.3 million for the Generation Unit Life Extension program and $2.0 million for new distribution line extenstions systems for customers.

**Credit Ratings** – On October 1, 2010, DBRS upgraded FortisBC to A (low) from BBB (high). The trend is Stable. The agency attributed the upgrade to the company's increased size and scale, supportive regulatory environment, solid project execution, strong parental support and a demonstrated ability to maintain stable credit metrics over the past five years, despite the continued capex-driven free cash flow deficits. Over the next few years, DBRS expects FortisBC's key credit metrics to improve modestly due to the combination of recent positive regulatory decisions and rate base additions.

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not Rated | Baa1 |
| Stable | | Stable |

**Disclosures:** 1, 2, 3, 4, 6A

# FortisBC Inc.

## Maturity Schedule

| Company | Coupon | Maturity | Amount ($mm) | Instrument | Issue Date | Issue Spread | Callable | CUSIP | Outstanding ($mm) |
|---|---|---|---|---|---|---|---|---|---|
| FortisBC Inc. | 9.65% | 16-Oct-12 | $15 | Secured Debenture | 16-Oct-92 | NA | Make Whole (+40.0 bps) | NA | $15 |
| FortisBC Inc. | 9.44% | 31-Oct-13 | $5 | WPP Mortgage | NA | NA | NA | NA | $3 |
| FortisBC Inc. | 5.48% | 28-Nov-14 | $140 | Unsecured Debenture | 30-Nov-04 | 97.0 bps | Make Whole ( + 24 bps) | 34957UAA3 | $140 |
| FortisBC Inc. | 8.77% | 01-Feb-16 | $25 | Unsecured Debenture | 01-Mar-96 | NA | Make Whole (+35.0 bps) | NA | $25 |
| FortisBC Inc. | 7.81% | 01-Dec-21 | $25 | Unsecured Debenture | 01-Jun-97 | NA | Make Whole (+25.0 bps) | NA | $25 |
| FortisBC Inc. | 8.80% | 28-Aug-23 | $25 | Secured Debenture | 30-Nov-93 | NA | Make Whole (+40.0 bps) | 95358DAA7 | $25 |
| FortisBC Inc. | 5.60% | 09-Nov-35 | $100 | Unsecured Debenture | 10-Nov-05 | 120.0 bps | Make Whole ( + 30 bps) | 34957UAB1 | $100 |
| FortisBC Inc. | 6.10% | 02-Jun-39 | $105 | Medium term note | 02-Jun-09 | 195.0 bps | Make Whole (+49 bps) | 34958ZAA1 | $105 |
| FortisBC Inc. | 5.90% | 04-Jul-47 | $105 | Unsecured Debenture | 04-Jul-07 | 125.0 bps | Make Whole ( + 31 bps) | 34957UAC9 | $105 |
| FortisBC Inc. | 5.00% | 24-Nov-50 | $100 | Medium term note | 24-Nov-10 | 135.0 bps | Make Whole ( + 33.5 bps) | 34958ZAB9 | $100 |

Source: Bloomberg, FP Bonds

## Ownership Structure

100% - Fortis Inc.

Source: Company Reports

## Credit Facilities ($mm)

| Company | Facility Size | Amount Available Q1/11 | Amount Available Q4/10 | Maturity | Type |
|---|---|---|---|---|---|
| FortisBC | $50.0 | | | 03-May-12 | 364-Day Revolving Term Facility |
| FortisBC | $100.0 | | | 07-May-14 | 3-Year Revolving Facility |
| FortisBC | $10.0 | | | | Demand Overdraft Facility |
| | | $160.0 | $158.8 | | |

Source: Company Reports

## Corp. Lease Schedule (12/31/2010)

| ($mm) Year | Operating Lease Payments |
|---|---|
| 2011 | 2.356 |
| 2012 | 2.123 |
| 2013 | 1.282 |
| 2014 | 1.344 |
| 2015 | 1.344 |
| Thereafter | 10.414 |

Source: Company Reports

## Shelf Prospectus

| Company | Type | Amount | Remaining | Date | Expiry | Instruments |
|---|---|---|---|---|---|---|
| FortisBC Inc. | Shelf | $300 | $95 | 22-May-09 | 22-Jun-11 | Medium Term Notes |

Source: SEDAR

## Pension Summary

| | Pension Benefit Plans FY2010 ($mm) | Pension Benefit Plans FY2009 ($mm) | Other Benefit Plans FY2010 ($mm) | Other Benefit Plans FY2009 ($mm) |
|---|---|---|---|---|
| Accrued Benefit Obligation | 143.0 | 126.7 | 23.6 | 17.2 |
| Plan Assets | 105.9 | 99.7 | 0.0 | 0.0 |
| Funded Status | (37.1) | (27.0) | (23.6) | (17.2) |
| Accrued Benefit Asset (Liability) Net of Valuation Allowance | 7.4 | 8.9 | (14.1) | (12.0) |
| Discount Rate (benefit cost) | 5.75% | 6.00% | 5.75% | 6.00% |
| Expected Long-term Rate of of Return on Assets | 7.00% | 7.00% | NA | NA |
| Rate of Future Increase in Compensation | 3.50% | 3.50% | 3.50% | 3.50% |

Source: Company Reports

## Historical Ratings
## Issuer Credit Rating – FortisBC Inc.

| DBRS Rating | DBRS Trend | DBRS Date | S&P Rating | S&P Trend | S&P Date | Moody's Rating | Moody's Trend | Moody's Date |
|---|---|---|---|---|---|---|---|---|
| A(low) | Stable | 01-Oct-10 | Not Rated | | | Baa1 | Stable | 06-May-10 |
| BBB (high) | Stable | 18-Nov-04 | | | | Baa2 | Stable | 21-Jun-07 |
| BBB (high) | Under Review - Developing | 16-Sep-03 | | | | Baa3 | UR-Pos | 18-Jun-07 |
| BBB (high) | Stable | 13-May-03 | | | | Baa3 | Stable | 16-Nov-04 |
| BBB (high) | Under Review - Negative | 28-Mar-03 | | | | | | |
| BBB (high) | Stable | 30-Dec-98 | | | | | | |

Source: DBRS, S&P, Moody's

## IMPORTANT DISCLOSURES

**Analyst's Certification**

I, Benjamin Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.

**Company Specific Disclosure**

Disclosure 1: BMO Capital Markets has undertaken an underwriting liability with respect to this issuer within the past 12 months.
Disclosure 2: BMO Capital Markets has provided investment banking services with respect to this issuer within the past 12 months.
Disclosure 3: BMO Capital Markets has managed or co-managed a public offering of securities with respect to this issuer within the past 12 months.
Disclosure 4: BMO Capital Markets or an affiliate has received compensation for investment banking services from this issuer within the past 12 months.
Disclosure 6: This issuer is a client (or was a client) of BMO NB, BMO Capital Markets Corp., BMO CM Ltd. or an affiliate within the past 12 months: Investment Banking Services.

**Distribution of Ratings (March 31, 2011)**

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 34.2% | 15.2% | 38.6% | 39.2% | 48.5% | 53.1% |
| Hold | Market Perform | 62.9% | 12.5% | 58.6% | 56.8% | 49.0% | 41.3% |
| Sell | Underperform | 2.9% | 13.3% | 2.9% | 4.1% | 2.5% | 5.5% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.
** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.
*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.
**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.
***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**

We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

**Other Important Disclosures**

For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Company_Disclosure_Public.asp or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**

http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**

Our research publications are available via our web site http://bmocapitalmarkets.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**

A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Conflict_Statement_Public.asp.

**General Disclaimer**

"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**

To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

**ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST**

BMO Financial Group (NYSE, TSX: BMO) is an integrated financial services provider offering a range of retail banking, wealth management, and investment and corporate banking products. BMO serves Canadian retail clients through BMO Bank of Montreal and BMO Nesbitt Burns. In the United States, retail clients are served through Harris N.A. Investment and corporate banking services are provided in Canada and the US through BMO Capital Markets.

BMO Capital Markets is a trade name used by BMO Financial Group for the wholesale banking businesses of Bank of Montreal, Harris N.A. and BMO Ireland Plc, and the institutional broker dealer businesses of BMO Capital Markets Corp. (Member SIPC), BMO Nesbitt Burns Trading Corp. and BMO Capital Markets GKST Inc. (Member SIPC) in the U.S., BMO Nesbitt Burns Inc. (Member CIPF) in Canada, Europe and Asia, BMO Nesbitt Burns Securities Limited (U.S. registered and member of FINRA), and BMO Nesbitt Burns Ltée/Ltd. (Member CIPF) in Canada, and BMO Capital Markets Limited in Europe and Australia. "Nesbitt Burns" is a registered trademark of BMO Nesbitt Burns Corporation Limited, used under license. "BMO Capital Markets" is a trademark of Bank of Montreal, used under license. "BMO (M-Bar roundel symbol)" is a registered trademark of Bank of Montreal, used under license.

® Registered trademark of Bank of Montreal in the United States, Canada and elsewhere.
TM Trademark Bank of Montreal



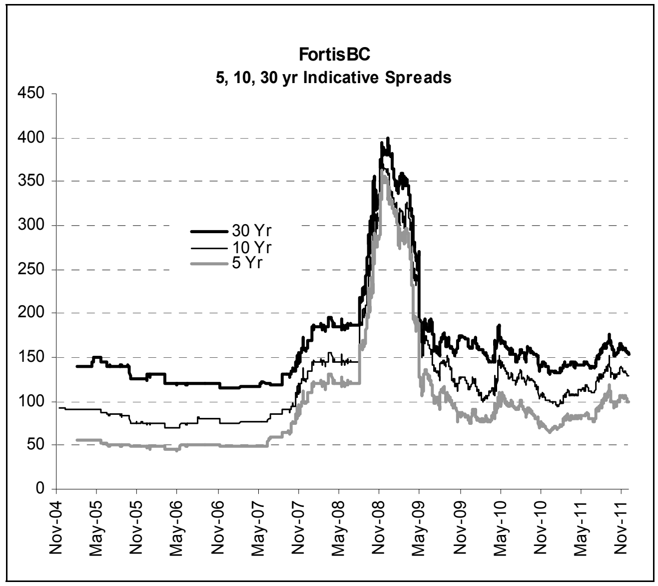
A member of BMO Financial Group

## Relative Value

**Recommendation –** We are maintaining our market weight recommendation on a 12-month relative basis, but hold a positive bias long term given improving credit fundamentals. We believe credit support is provided by a stable regulatory regime and the independent structure between the holding company, Fortis Inc., and the operating company, FortisBC. We believe FortisBC will operate as a stand-alone entity and that it will carry out all of the debt financing requirements at the operating company level.

**Sector Value** – We believe FortisBC's indicative credit spreads are reasonably valued at current levels. The 5-year, 10-year and 30-year spread differentials between FortisBC and Hydro One are currently 9 bps, 9 bps and 5 bps, respectively.

**Credit Curve –** FortisBC's 10s–30s curve is at roughly 25 bps, while its 5s–10s is around 29 bps, suggesting there is some relative value in the middle part of its curve.




Source: BMO Capital Markets

## Risks

**External –** Severe weather conditions and natural disasters may result in the interruption of electricity service, which could have a material adverse effect on the company's operations, cash flows and financial position. The company has limited insurance against storm damage and other natural disasters.

**M&A –** FortisBC's current focus is on rate base growth within its service territory.

**Regulatory –** The utility operations of the company are subject to the regulatory determinations of the British Columbia Utilities Commission, with respect to rates, capital expenditures and the authorized return on equity.

**Trading Liquidity** – We believe FortisBC exhibits below-average trading liquidity in the Canadian bond market.

**New Issuance –** Cash flow from operating activities will likely not be adequate to meet capital expenditure and dividend requirements over the forecast period. Therefore, access to capital markets will be required. We expect proceeds of new debt issues will be used to pay down operating credit facilities used to finance the company's capital expenditure program.

**Other** – An extended decline in British Columbia's economy or in the company's service area is likely to reduce electricity demand over time. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth.

## Credit Profile

**Company Financials –** FortisBC reported net earnings of $9.5 million in Q3/11, a $1.0 million decrease over the same period last year. The variance was primarily due to a decrease in allowance for funds used during construction (capitalized financing costs) and higher income taxes resulting from unfavorable tax timing differences.

FortisBC had $636.5 million of long-term debt outstanding at September 30, 2011. FortisBC's debt to capitalization ratio of 58.1% as at Q3/11 decreased 141 bps from 59.5% as at year-end 2010. FortisBC's authorized bank credit facilities of $160 million comprise of a $150 million (Facility A: $100 million to mature May 7, 2014; Facility B: $50 million maturing May 3, 2012) operating credit facility and a $10 million demand overdraft facility. At the end of Q3/11, FortisBC had $160 million available on these facilities.

**Company Fundamentals –** FortisBC expects the total number of customer accounts to increase 2.3% over the next five years, well above the 20-year average of 1.4%.

**Capex –** FortisBC has forecast capital expenditures of $95 million, net of customer contributions for 2011. Year-to-date 2011, FortisBC has spent $63.8 million. Significant capital projects include $12.1 million for the Okanagan Transmission Reinforcement Project, $11.5 million for the Generation Unit Life Extension program and $7.2 million for new distribution line extension systems for customers. Also, per its 2012–2013 Capital Expenditure Plan dated June 30, 2011, capital expenditures are expected to be $100.1 million in 2012 and $123.2 million in 2013.

**Credit Ratings –** On October 1, 2010, DBRS upgraded FortisBC to A (low) from BBB (high). The trend is Stable. The agency attributed the upgrade to the company's increased size and scale, supportive regulatory environment, solid project execution, strong parental support and a demonstrated ability to maintain stable credit metrics over the past five years, despite the continued capex-driven free cash flow deficits. Over the next few years, DBRS expects FortisBC's key credit metrics to improve modestly due to the combination of recent positive regulatory decisions and rate base additions.

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not Rated | Baa1 |
| Stable | | Stable |

# FortisBC Inc.

## Maturity Schedule

| Company | Coupon | Maturity | Amount ($mm) | Instrument | Issue Date | Issue Spread | Callable | CUSIP | Outstanding ($mm) |
|---|---|---|---|---|---|---|---|---|---|
| FortisBC Inc. | 9.65% | 16-Oct-12 | $15 | Secured Debenture | 16-Oct-92 | NA | Make Whole (+40.0 bps) | NA | $15 |
| FortisBC Inc. | 9.44% | 31-Oct-13 | $5 | WPP Mortgage | NA | NA | NA | NA | $2 |
| FortisBC Inc. | 5.48% | 28-Nov-14 | $140 | Unsecured Debenture | 30-Nov-04 | 97.0 bps | Make Whole ( + 24 bps) | 34957UAA3 | $140 |
| FortisBC Inc. | 8.77% | 01-Feb-16 | $25 | Unsecured Debenture | 01-Mar-96 | NA | Make Whole (+35.0 bps) | NA | $25 |
| FortisBC Inc. | 7.81% | 01-Dec-21 | $25 | Unsecured Debenture | 01-Jun-97 | NA | Make Whole (+25.0 bps) | NA | $25 |
| FortisBC Inc. | 8.80% | 28-Aug-23 | $25 | Secured Debenture | 30-Nov-93 | NA | Make Whole (+40.0 bps) | 95358DAA7 | $25 |
| FortisBC Inc. | 5.60% | 09-Nov-35 | $100 | Unsecured Debenture | 10-Nov-05 | 120.0 bps | Make Whole ( + 30 bps) | 34957UAB1 | $100 |
| FortisBC Inc. | 6.10% | 02-Jun-39 | $105 | Medium term note | 02-Jun-09 | 195.0 bps | Make Whole (+49 bps) | 34958ZAA1 | $105 |
| FortisBC Inc. | 5.90% | 04-Jul-47 | $105 | Unsecured Debenture | 04-Jul-07 | 125.0 bps | Make Whole ( + 31 bps) | 34957UAC9 | $105 |
| FortisBC Inc. | 5.00% | 24-Nov-50 | $100 | Medium term note | 24-Nov-10 | 135.0 bps | Make Whole ( + 33.5 bps) | 34958ZAB9 | $100 |

Source: Bloomberg, FP Bonds

## Ownership Structure

100% - Fortis Inc.

## Credit Facilities ($mm)

| Company | Facility Size | Amount Available Q3/11 | Amount Available Q2/11 | Maturity | Type |
|---|---|---|---|---|---|
| FortisBC | $50.0 | | | 03-May-12 | 364-Day Revolving Term Facility |
| FortisBC | $100.0 | | | 07-May-14 | 3-Year Revolving Facility |
| FortisBC | $10.0 | | | | Demand Overdraft Facility |
| | | $160.0 | $142.2 | | |

Source: Company Reports

## Corp. Lease Schedule (12/31/2010)

| ($mm) Year | Operating Lease Payments |
|---|---|
| 2011 | 2.356 |
| 2012 | 2.123 |
| 2013 | 1.282 |
| 2014 | 1.344 |
| 2015 | 1.344 |
| Thereafter | 10.414 |

Source: Company Reports

## Shelf Prospectus

| Company | Type | Amount | Remaining | Date | Expiry | Instruments |
|---|---|---|---|---|---|---|
| None. | | | | | | |

Source: SEDAR

## Pension Summary

| | Pension Benefit Plans FY2010 ($mm) | Pension Benefit Plans FY2009 ($mm) | Other Benefit Plans FY2010 ($mm) | Other Benefit Plans FY2009 ($mm) |
|---|---|---|---|---|
| Accrued Benefit Obligation | 143.0 | 126.7 | 23.6 | 17.2 |
| Plan Assets | 105.9 | 99.7 | 0.0 | 0.0 |
| Funded Status | (37.1) | (27.0) | (23.6) | (17.2) |
| Accrued Benefit Asset (Liability) Net of Valuation Allowance | 7.4 | 8.9 | (14.1) | (12.0) |
| Discount Rate (benefit cost) | 5.75% | 6.00% | 5.75% | 6.00% |
| Expected Long-term Rate of of Return on Assets | 7.00% | 7.00% | NA | NA |
| Rate of Future Increase in Compensation | 3.50% | 3.50% | 3.50% | 3.50% |

Source: Company Reports

## Historical Ratings
### Issuer Credit Rating – FortisBC Inc.

| DBRS Rating | Trend | Date | S&P Rating | Trend | Date | Moody's Rating | Trend | Date |
|---|---|---|---|---|---|---|---|---|
| A(low) | Stable | 01-Oct-10 | Not Rated | | | Baa1 | Stable | 06-May-10 |
| BBB (high) | Stable | 18-Nov-04 | | | | Baa2 | Stable | 21-Jun-07 |
| BBB (high) | Under Review - Developing | 16-Sep-03 | | | | Baa3 | UR-Pos | 18-Jun-07 |
| BBB (high) | Stable | 13-May-03 | | | | Baa3 | Stable | 16-Nov-04 |
| BBB (high) | Under Review - Negative | 28-Mar-03 | | | | | | |
| BBB (high) | Stable | 30-Dec-98 | | | | | | |

Source: DBRS, S&P, Moody's

## IMPORTANT DISCLOSURES

### Analyst's Certification

I, Benjamin Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.

### Distribution of Ratings (September 30, 2011)

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 39.2% | 12.6% | 38.8% | 42.5% | 48.1% | 57.2% |
| Hold | Market Perform | 58.9% | 13.2% | 61.2% | 54.6% | 50.9% | 38.5% |
| Sell | Underperform | 1.9% | 0.0% | 0.0% | 2.9% | 0.9% | 4.3% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.

** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.

*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.

**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.

***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

### Ratings and Sector Key

We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

### Other Important Disclosures

For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Company_Disclosure_Public.asp or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

### Prior BMO Capital Markets Ratings Systems

http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

### Dissemination of Research

Our research publications are available via our web site http://bmocapitalmarkets.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

### Conflict Statement

A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Conflict_Statement_Public.asp.

**General Disclaimer**

"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**

To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

**ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST**

BMO Financial Group (NYSE, TSX: BMO) is an integrated financial services provider offering a range of retail banking, wealth management, and investment and corporate banking products. BMO serves Canadian retail clients through BMO Bank of Montreal and BMO Nesbitt Burns. In the United States, personal and commercial banking clients are served by BMO Harris Bank N.A., (Member FDIC). Investment and corporate banking services are provided in Canada and the US through BMO Capital Markets.

BMO Capital Markets is a trade name used by BMO Financial Group for the wholesale banking businesses of Bank of Montreal, BMO Harris Bank N.A (Member FDIC), BMO Ireland Plc, and Bank of Montreal (China) Co. Ltd. and the institutional broker dealer businesses of BMO Capital Markets Corp. (Member SIPC), BMO Nesbitt Burns Trading Corp. S.A., BMO Nesbitt Burns Securities Limited (Member SIPC) and BMO Capital Markets GKST Inc. (Member SIPC) in the U.S., BMO Nesbitt Burns Inc. (Member Canadian Investor Protection Fund) in Canada, Europe and Asia, BMO Nesbitt Burns Ltée/Ltd. (Member Canadian Investor Protection Fund) in Canada, BMO Capital Markets Limited in Europe, Asia and Australia and BMO Advisors Private Limited in India.



A member of **BMO Financial Group**

# FortisBC Inc.

February 9, 2012
Brief Research Note

**Ben Pham, CFA**
(416) 359-4061
ben.pham@bmo.com
Assoc: Ewa Bzorek, CA

## Q4 – Higher Than Expected

### Impact

Neutral.

### Details & Analysis

Fortis Inc. reported fourth-quarter results this morning, providing a preview of quarterly financial results of its 100%-owned subsidiary FortisBC. Highlights for FortisBC: (1) the company reported earnings of $11 million in Q4/11, an increase of roughly $1.0 million over the same period last year. The variance was primarily due to rate base growth and lower energy supply costs, partially offset by a higher effective tax rate, lower electricity sales and higher operating expenses; (2) the company has forecast total capital expenditures for 2012 of approximately $111 million, compared to 2011 capex levels of $102 million. Notably, the $105 million Okanagan Reinforcement Project was substantially completed in the fall of 2011, which involved upgrading the existing overhead transmission line between Penticton and Vaseux Lake from 161kV to a double-circuit 230 kV line and building a new 230kV substation in the Oliver area; and (3) in November 2011, FortisBC filed a revised revenue requirement application for 2012 and 2013 rates, reflecting mid-year rate base of $1,146 million in 2012 and $1,215 million in 2013. An oral hearing process is expected to occur in March 2012 with a decision on the rate application expected during 2012. We do not think FortisBC has a need for new public debt issues this year, but are not ruling out a possible deal near year-end given the favourable funding environment and the desire to top up liquidity heading into 2013. Maintaining market weight investment recommendation.

### Senior Unsecured Debt Ratings

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not rated | Baa1 |
| Stable | | Stable |

**This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered as a research analyst under FINRA rules. For disclosure statements, including the Analyst's Certification, please refer to pages 2 to 3.**

**IMPORTANT DISCLOSURES**

**Analyst's Certification**
I, Ben Pham, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.

**Methodology and Risks to Price Target/Valuation**
**Methodology**: Our target price is based on a weighted valuation approach: 18x diluted 2012E EPS (12.5%); 1.75x 2012E BVPS (12.5%) and a target yield of 3.50% based on 2012E dividends per share (75%).
**Risks**: Operations are subject to complex regulation by a variety of provincial, state and federal (Canada, Cayman Islands & Belize) agencies. Changes in regulation may adversely affect performance.

**Company Specific Disclosure**
Disclosure 1: BMO Capital Markets has undertaken an underwriting liability with respect to this issuer within the past 12 months.
Disclosure 2: BMO Capital Markets has provided investment banking services with respect to this issuer within the past 12 months.
Disclosure 3: BMO Capital Markets has managed or co-managed a public offering of securities with respect to this issuer within the past 12 months.
Disclosure 4: BMO Capital Markets or an affiliate has received compensation for investment banking services from this issuer within the past 12 months.
Disclosure 5: BMO Capital Markets or an affiliate received compensation for products or services other than investment banking services within the past 12 months.
Disclosure 6: This issuer is a client (or was a client) of BMO NB, BMO Capital Markets Corp., BMO CM Ltd. or an affiliate within the past 12 months: Investment Banking Services & Non-Securities Related Services.

## Distribution of Ratings (December 30, 2011)

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 38.0% | 10.3% | 40.4% | 40.7% | 46.2% | 56.2% |
| Hold | Market Perform | 60.3% | 9.6% | 59.6% | 56.3% | 52.2% | 39.4% |
| Sell | Underperform | 1.7% | 0.0% | 0.0% | 3.0% | 1.6% | 4.4% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.
** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.
*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.
**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.
***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**
We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

**Other Important Disclosures**
For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Company_Disclosure_Public.asp or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**
http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**
Our research publications are available via our web site http://bmocapitalmarkets.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**
A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Conflict_Statement_Public.asp.

**General Disclaimer**
"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**
To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to,

(I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

# FortisBC Inc.

May 2, 2012
Brief Research Note

**Mark Laing, CA, CFA**
(416) 359-4601
Mark.Laing@bmo.com
Assoc: Kathryn Nixon

## Q1 – Lower Than Expected

### Impact

Neutral.

### Details & Analysis

Fortis Inc. reported first-quarter results this morning, providing a preview of quarterly financial results of its 100%-owned subsidiary FortisBC. Highlights for FortisBC: (1) the company reported earnings of $16 million in Q1/12, a decrease of roughly $3.0 million over the same period last year. The variance was primarily due to the expiry of the performance-based rate-setting mechanism on December 31, 2011, which resulted in increased operating expenses during the quarter; (2) the company did not make any material changes to forecasted total capital expenditures for 2012 of approximately $111 million, compared to 2011 capex levels of $102 million; (3) in November 2011, FortisBC filed a revised revenue requirement application for 2012 and 2013 rates, reflecting mid-year rate base of $1.146 billion in 2012 and $1.215 billion in 2013. An oral hearing process occurred in March 2012 with a decision expected mid-2012; and (4) FortisBC renegotiated and amended its credit facility agreement to extend the maturity of its $150 million unsecured committed revolving credit facility, with $100 million now maturing in May 2015 and $50 million maturing in May 2013. We do not believe FortisBC has a need for new public debt issues this year and we are maintaining our market weight investment recommendation.

### Senior Unsecured Debt Ratings

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not rated | Baa1 |
| Stable | | Stable |

**This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered as a research analyst under FINRA rules. For disclosure statements, including the Analyst's Certification, please refer to pages 2 to 3.**

**IMPORTANT DISCLOSURES**

**Analyst's Certification**
I, Mark Laing, CA, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.
Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.
Analysts employed by BMO Nesbitt Burns Inc. and/or BMO Capital Markets Ltd. are not registered as research analysts with FINRA. These analysts may not be associated persons of BMO Capital Markets Corp. and therefore may not be subject to the NASD Rule 2711 and NYSE Rule 472 restrictions on communications with a subject company, public appearances and trading securities held by a research analyst account.

### Distribution of Ratings (March 31, 2012)

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 37.7% | 12.1% | 52.1% | 39.2% | 48.3% | 54.6% |
| Hold | Market Perform | 60.0% | 7.0% | 47.9% | 57.6% | 51.0% | 40.1% |
| Sell | Underperform | 2.4% | 0.0% | 0.0% | 3.2% | 0.7% | 5.3% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.
** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.
*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.
**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.
***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**
We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets eight Top 15 lists guide investors to our best ideas according to different objectives (Canadian large, small, growth, value, income, quantitative; and US large, US small) have replaced the Top Pick rating.

**Other Important Disclosures**
For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Public/Company_Disclosure_Public.aspx or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**
http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**
Our research publications are available via our web site http://www.bmocm.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com. All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research.

Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**
A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Public/Conflict_Statement_Public.aspx.

**General Disclaimer**
"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**
To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.
To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.
To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

**ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST**

BMO Financial Group (NYSE, TSX: BMO) is an integrated financial services provider offering a range of retail banking, wealth management, and investment and corporate banking products. BMO serves Canadian retail clients through BMO Bank of Montreal and BMO Nesbitt Burns. In the United States, personal and commercial banking clients are served by BMO Harris Bank N.A., (Member FDIC). Investment and corporate banking services are provided in Canada and the US through BMO Capital Markets.

BMO Capital Markets is a trade name used by BMO Financial Group for the wholesale banking businesses of Bank of Montreal, BMO Harris Bank N.A (Member FDIC), BMO Ireland Plc, and Bank of Montreal (China) Co. Ltd. and the institutional broker dealer businesses of BMO Capital Markets Corp. (Member SIPC), BMO Nesbitt Burns Trading Corp. S.A., BMO Nesbitt Burns Securities Limited (Member SIPC) and BMO Capital Markets GKST Inc. (Member SIPC) in the U.S., BMO Nesbitt Burns Inc. (Member Canadian Investor Protection Fund) in Canada, Europe and Asia, BMO Nesbitt Burns Ltée/Ltd. (Member Canadian Investor Protection Fund) in Canada, BMO Capital Markets Limited in Europe, Asia and Australia and BMO Advisors Private Limited in India.

# FortisBC Inc.

**July 31, 2012**
Brief Research Note

**Mark Laing, CA, CFA**
(416) 359-4601
Mark.Laing@bmo.com
Assoc: Kathryn Nixon

## Q2 – In Line

### Impact

Neutral.

### Details & Analysis

Fortis Inc. reported second-quarter results this morning, providing a preview of quarterly financial results of its 100%-owned subsidiary FortisBC. Highlights for FortisBC: (1) the company reported earnings of $9 million in Q2/12, consistent with the $9 million recorded in the same period last year; (2) the company did not make any material changes to forecasted total capital expenditures for 2012 of approximately $111 million, compared to 2011 capex levels of $102 million; (3) in November 2011, FortisBC filed a revised revenue requirement application for 2012 and 2013 rates, reflecting mid-year rate base of $1.146 billion in 2012 and $1.215 billion in 2013. An oral hearing process occurred in March 2012 and a decision is expected in Q3/12; (4) FortisBC is in preliminary discussion with the city of Kelowna B.C. to purchase the city's electricity distribution utility, which serves approximately 15,000 customers. The parties are working toward closing the transaction by the end of Q1/13; and (5) in April 2012, FortisBC renegotiated and amended its credit facility agreement to extend the maturity of its $150 million unsecured committed revolving credit facility, with $100 million now maturing in May 2015 and $50 million maturing in May 2013. We do not believe FortisBC has a need for new public debt issues this year and we are maintaining our market weight investment recommendation.

### Senior Unsecured Debt Ratings

| DBRS | S&P | Moody's |
|---|---|---|
| A (low) | Not rated | Baa1 |
| Stable | | Stable |

**This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered as a research analyst under FINRA rules. For disclosure statements, including the Analyst's Certification, please refer to pages 2 to 3.**

## IMPORTANT DISCLOSURES

**Analyst's Certification**
I, Mark Laing, CA, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.
Analysts who prepared this report are compensated based upon (among other factors) the overall profitability of BMO Capital Markets and their affiliates, which includes the overall profitability of investment banking services. Compensation for research is based on effectiveness in generating new ideas and in communication of ideas to clients, performance of recommendations, accuracy of earnings estimates, and service to clients.
Analysts employed by BMO Nesbitt Burns Inc. and/or BMO Capital Markets Ltd. are not registered as research analysts with FINRA. These analysts may not be associated persons of BMO Capital Markets Corp. and therefore may not be subject to the NASD Rule 2711 and NYSE Rule 472 restrictions on communications with a subject company, public appearances and trading securities held by a research analyst account.

**Company Specific Disclosure**
Disclosure 5: BMO Capital Markets or an affiliate received compensation for products or services other than investment banking services within the past 12 months.
Disclosure 6: This issuer is a client (or was a client) of BMO NB, BMO Capital Markets Corp., BMO CM Ltd. or an affiliate within the past 12 months: Non-Securities Related Services.

**Distribution of Ratings (June 30, 2012)**

| Rating Category | BMO Rating | BMOCM US Universe* | BMOCM US IB Clients** | BMOCM US IB Clients*** | BMOCM Universe**** | BMOCM IB Clients***** | Starmine Universe |
|---|---|---|---|---|---|---|---|
| Buy | Outperform | 39.2% | 14.2% | 66.0% | 39.7% | 49.1% | 55.7% |
| Hold | Market Perform | 58.8% | 4.6% | 31.9% | 57.1% | 48.6% | 39.3% |
| Sell | Underperform | 2.0% | 9.1% | 2.1% | 3.2% | 2.3% | 5.0% |

* Reflects rating distribution of all companies covered by BMO Capital Markets Corp. equity research analysts.
** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage within ratings category.
*** Reflects rating distribution of all companies from which BMO Capital Markets Corp. has received compensation for Investment Banking services as percentage of Investment Banking clients.
**** Reflects rating distribution of all companies covered by BMO Capital Markets equity research analysts.
***** Reflects rating distribution of all companies from which BMO Capital Markets has received compensation for Investment Banking services as percentage of Investment Banking clients.

**Ratings and Sector Key**
We use the following ratings system definitions:
OP = Outperform - Forecast to outperform the market;
Mkt = Market Perform - Forecast to perform roughly in line with the market;
Und = Underperform - Forecast to underperform the market;
(S) = speculative investment;
NR = No rating at this time;
R = Restricted – Dissemination of research is currently restricted.

Market performance is measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company. BMO Capital Markets' seven Top 15 lists guide investors to our best ideas according to different objectives (CDN Large Cap, CDN Small Cap, US Large Cap, US Small cap, Income, CDN Quant, and US Quant) have replaced the Top Pick rating.

**Other Important Disclosures**
For Other Important Disclosures on the stocks discussed in this report, please go to http://researchglobal.bmocapitalmarkets.com/Public/Company_Disclosure_Public.aspx or write to Editorial Department, BMO Capital Markets, 3 Times Square, New York, NY 10036 or Editorial Department, BMO Capital Markets, 1 First Canadian Place, Toronto, Ontario, M5X 1H3.

**Prior BMO Capital Markets Ratings Systems**
http://researchglobal.bmocapitalmarkets.com/documents/2009/prior_rating_systems.pdf

**Dissemination of Research**
Our research publications are available via our web site http://www.bmocm.com/research/. Institutional clients may also receive our research via FIRST CALL, FIRST CALL Research Direct, Reuters, Bloomberg, FactSet, Capital IQ, and TheMarkets.com.

All of our research is made widely available at the same time to all BMO Capital Markets client groups entitled to our research. Additional dissemination may occur via email or regular mail. Please contact your investment advisor or institutional salesperson for more information.

**Conflict Statement**

A general description of how BMO Financial Group identifies and manages conflicts of interest is contained in our public facing policy for managing conflicts of interest in connection with investment research which is available at http://researchglobal.bmocapitalmarkets.com/Public/Conflict_Statement_Public.aspx.

**General Disclaimer**

"BMO Capital Markets" is a trade name used by the BMO Investment Banking Group, which includes the wholesale arm of Bank of Montreal and its subsidiaries BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltée./Ltd., BMO Capital Markets Ltd. in the U.K. and BMO Capital Markets Corp. in the U.S. BMO Nesbitt Burns Inc., BMO Capital Markets Ltd. and BMO Capital Markets Corp are affiliates. Bank of Montreal or its subsidiaries ("BMO Financial Group") has lending arrangements with, or provide other remunerated services to, many issuers covered by BMO Capital Markets. The opinions, estimates and projections contained in this report are those of BMO Capital Markets as of the date of this report and are subject to change without notice. BMO Capital Markets endeavours to ensure that the contents have been compiled or derived from sources that we believe are reliable and contain information and opinions that are accurate and complete. However, BMO Capital Markets makes no representation or warranty, express or implied, in respect thereof, takes no responsibility for any errors and omissions contained herein and accepts no liability whatsoever for any loss arising from any use of, or reliance on, this report or its contents. Information may be available to BMO Capital Markets or its affiliates that is not reflected in this report. The information in this report is not intended to be used as the primary basis of investment decisions, and because of individual client objectives, should not be construed as advice designed to meet the particular investment needs of any investor. This material is for information purposes only and is not an offer to sell or the solicitation of an offer to buy any security. BMO Capital Markets or its affiliates will buy from or sell to customers the securities of issuers mentioned in this report on a principal basis. BMO Capital Markets or its affiliates, officers, directors or employees have a long or short position in many of the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon. The reader should assume that BMO Capital Markets or its affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

**Additional Matters**

To Canadian Residents: BMO Nesbitt Burns Inc. and BMO Nesbitt Burns Ltee/Ltd., affiliates of BMO Capital Markets Corp., furnish this report to Canadian residents and accept responsibility for the contents herein subject to the terms set out above. Any Canadian person wishing to effect transactions in any of the securities included in this report should do so through BMO Nesbitt Burns Inc. and/or BMO Nesbitt Burns Ltee/Ltd.

To U.S. Residents: BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO NB, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through BMO Capital Markets Corp. and/or BMO Nesbitt Burns Securities Ltd.

To U.K. Residents: In the UK this document is published by BMO Capital Markets Limited which is authorised and regulated by the Financial Services Authority. The contents hereof are intended solely for the use of, and may only be issued or passed on to, (I) persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (II) high net worth entities falling within Article 49(2)(a) to (d) of the Order (all such persons together referred to as "relevant persons"). The contents hereof are not intended for the use of and may not be issued or passed on to, retail clients.

**FortisBC Inc. (BBB(high)/ n.r./ Baa2)** is, on the surface, just a small company with very modest credit ratings, with small, infrequent offerings in the Canadian corporate bond market. Looking beyond the surface, however, we see much to admire. Earnings and cash flow from operations have been steadily improving since **Fortis Inc.'s (BBB(high)/ A-/ n.r.)** acquisition in May, 2004. The asset base has grown steadily, in response to system upgrades and equipment life extensions, and strong organic growth in the Okanagan Valley service area. Operating safety, reliability, and customer satisfaction measures have all improved, and a series of rate settlement agreements with ratepayers attests to a constructive relationship between the company, its stakeholders, and the regulator. Most recently, the regulator's significant reform on the cost of capital has largely addressed concerns we have had on financial performance and flexibility. In our view, the materially higher ROE improves FortisBC's attractiveness to parent Fortis Inc., and maintains the incentive for Fortis Inc. to continue to make necessary equity investments, in the face of ongoing negative free cash flow due to capital spending demands. As a result of these and other positive factors, we see upgrade potential from both rating agencies, despite what we expect will be continuing capital expansion. While outstanding FortisBC bonds trade infrequently, we believe they offer very fair value at current spreads. With what we see as zero downgrade risk, FortisBC bonds can be considered low-risk additions to a corporate portfolio, despite currently modest credit ratings. While we would not expect much spread tightening on a single rating agency upgrade, we see potential for two ratings upgrades in the next 12 months or so, which could give a nice valuation lift for bonds that we think make a fine defensive investment.

BCUC ROE Decision

While the British Columbia Utilities Commission (BCUC)'s December 16th Return on Equity and Capital Structure Decision is already well-known to the bond market, we continue to view it as supportive of gradual spread narrowing for the affected companies, as it fosters modestly better credit ratios, beginning in Q1 this year. FortisBC's allowed ROE will rise to 9.90%, from 8.87% in 2009, 9.02% in 2008, and 8.77% in 2007. We estimate this will benefit interest coverage by just over 0.1x, which we view as modest, but meaningful.

The BCUC ROE review was initiated by the rate application of Terasen Gas Inc., which is viewed by the BCUC as the "benchmark utility" in the province. The Decision reaffirmed FortisBC's extra 40 bps of ROE, compared to the 9.50% assigned to the "benchmark" Terasen Gas, in line with the established ROE differential the BCUC has judged appropriate for FortisBC.

However, while the ROE decision raised the equity of Terasen Gas Inc. from 35% to 40%, it left the equity capitalization of Terasen Gas Vancouver Island, Terasen Gas Whistler, and FortisBC all unchanged at 40%. It is not clear to us from the wording of the Decision and the related Order that the BCUC has ruled out increasing the equity capitalization of these other utilities. We think it possible, but not certain, that FortisBC could request a higher equity capitalization at its next cost of service rate case. However, as FortisBC's current performance-based regulation (PBR) settlement agreement runs to the end of 2011, we think that a rate proceeding beginning in 2011 for the 2012 rate year would be the first opportunity for FortisBC to make such a request.

2010 Rate Settlement

Since 2006, FortisBC has operated under a PBR agreement. The initial term, to 2008, has been extended to 2011. The BCUC's process under the PBR involves annual reviews of FortisBC's performance vis-à-vis reliability, safety, and other standards, before FortisBC can retain earnings above the allowed ROE. Annual reviews also establish the revenue requirement for the next rate year. On October 1st, 2009, FortisBC filed an application requesting an average 4.6% rate increase for 2010. The request was amended to 4.0% on November 2nd, and a settlement agreement for a 3.5% increase was proposed following stakeholder discussions on November 18th.

The BCUC approved the 3.5% settlement, which was increased by an additional 2.5% following the December ROE Decision's increase of the allowed ROE to 9.90%, from 8.87% allowed in 2009. The final rate increase of 6.0% became effective on January 1st. We consider the process (except for the ROE's 2.5% rate impact) as consistent with the pattern of preceding years, and indicative of generally healthy relations between the company, its stakeholders, and the regulatory body.

2009 Rate Design Application

Reviews of "rate design" assess the fairness of the rate structure's different fixed and variable cost components across the various classes of residential, commercial, industrial, and institutional customers. Such reviews are usually conducted infrequently, and the last such review for FortisBC was in 1997.

At the request of the BCUC, FortisBC filed its 2009 Rate Design Application on October 30th, 2009. In this case, the application also addresses recent provincial energy policy initiatives and legislation. In particular, pursuant to the provincial government's 2007 B.C. Energy Plan, all utilities are urged to explore "new rate structures that encourage energy efficiency and conservation." The 2009 Rate Design Application addresses these issues as well.

The application, with associated background documents and stakeholder consultations, represents a significant investment in utility cost and management time. However, the intent of such reviews is to leave total utility revenue unchanged, and merely rearrange costs, if necessary, among the different customer classes. As such, we view it as very likely neutral for credit quality, though we will follow it with interest. The oral hearing commences on May 3rd, 2010.

2009-2010 Capital Expenditure Plan

FortisBC's current capital plan, for 2009-2010, was approved by the BCUC in February 2009, largely as filed, with the exception of the proposed Cora Linn 2 generation station upgrades. The BCUC required a separate application for this project, in light of its size (roughly $20 million), and an incomplete turbine condition assessment. After FortisBC submitted more information on Cora Linn 2 in July, and no opposition to the project emerged, the BCUC issued its approval to proceed with the Cora Linn 2 upgrades in September. This project, scheduled for completion in 2012, is the last stage of the Upgrade and Life Extension program for FortisBC's hydroelectric generation facilities, which has been ongoing for the past decade. Upon its completion, FortisBC's generation assets will have been modernized "from water to wire", improving reliability and productivity.

The single largest project in the 2009-2010 capex plan (in fact, the largest ever capital project undertaken by FortisBC) is the Okanagan Transmission Reinforcement project. This project, begun in 2008, involves upgrading existing transmission lines from 161 kV to 230 kV, constructing an additional 230 kV line, and bolstering substation capacity. The project will enhance capacity to meet demand growth, and improve reliability in the Okanagan area. Roughly $30 million of the $110 million total cost for this project has been incurred to date. The project is expected to be completed (and thus will be added to rate base and begin generating cash flow) in mid-2011.

Other ongoing capital work includes the installation of communications, metering, and protection systems in distribution substations. The project will allow real-time visibility of station conditions, and the centralized, remote operation of all substations' switching operations by a single system control centre, to improve safety, reliability, and productivity. Ultimately, the system control centre will operate the entire generation, transmission, and distribution systems, again, to improve safety, reliability and outage response time, and productivity.

FortisBC's capital budget for 2010 is $160 million, net of $8 million in customer contributions. This represents a sizable increase from 2009 actual capex of $110 million. However, the 2009 budget forecast was for capex of $146 million, which was not achieved, in part due to delays in construction of the Okanagan Transmission Reinforcement project. Despite the delays, we view execution risk for this large transmission project, and all FortisBC's other capital programs, as minimal. FortisBC does not proceed with project execution prior to approval by the BCUC, which we view as minimizing the risk of a completed project not entering rate base. FortisBC does, however, engage in comprehensive pre-project planning and consultation with the relevant stakeholders, which we think reflects well on management's capability to smoothly plan and execute capital works, and minimize credit risk related to capital spending.

Current capital spending plans, longer-term plans outlined in FortisBC's latest 20-year Resource Plan filed with the regulator, as well as provincial government initiatives to "green" the provincial energy mix and aggressively instil conservation measures will, we believe, lead to FortisBC incurring free cash flow deficits for at least the next several years. This will lead to regular financing requirements, and has drawn the notice of the rating agencies. We are comfortable with the willingness of the regulator to allow these prudently-incurred capital costs into rate base in a timely fashion. We think the willingness and ability of Fortis Inc. to provide the necessary equity financing to maintain equity capitalization in line with deemed regulatory levels is very strong. As such, we see minimal credit risk stemming from these free cash flow deficits.

Supply and the 2009 Resource Plan

In its 2009 letter to the shareholder, FortisBC noted "Future energy supply is critical and FortisBC continues to evaluate potential new sources of energy supply." FortisBC also said "the nature of regulatory filings is evolving from a focus on the transmission and distribution system to initiatives driven by new (B.C. government) policy regulations and energy supply."

In this vein, FortisBC filed its 2009 Resource Plan with the regulator in May, 2009. The plan looks forward 20 years, and assesses the gap between current capacity and supply with expected demand. The plan is mindful of the provincial government's ambitious 2007 B.C. Energy Plan, which aims to put the province in a leadership position for conservation, efficiency, self-sufficiency of supply, and having clean or renewable generation account for 90% of total provincial generation.

At present, FortisBC's four Kootenay River plants provide about 45% of the annual energy requirement, and 30% of capacity requirements. The bulk of remaining energy and capacity needs are met through the Brilliant Power PPA, the BC Hydro PPA, and small contracts with independent producers. Spot market purchases supplement these contracted purchases, at prices typically tied to the Mid-Columbia index, which in turn tends to follow trends in natural gas prices.

The combined firm capacity of the FortisBC system includes 223 MW from its own plants, 200 MW from the long-term contract with BC Hydro, and 149 MW from the long term contract with Brilliant Power, for total firm long-term capacity of approximately 572 MW. FortisBC's seasonal load profile still displays a winter peak, which reached 746 MW in 2008, though the summer peak is growing more rapidly, due to a rising air conditioning load. This load profile will, over time, further increase the system's capacity requirements. The peak capacity shortfall will grow from the 2009 Resource Plan's estimated 145 MW for 2009, to 239 MW in 2028. Mid-Columbia prices, which have been volatile at times in the past, are expected to rise, owing to expected tight supply. Additionally, FortisBC currently has limited short term supply reserve margins in the event of generation or transmission outages.

FortisBC's 2009 Resource Plan concludes it would be prudent to develop a "hybrid" portfolio of energy and capacity resources as follows:

- 2014 two 42 MW simple-cycle gas turbine units
- 2017 40 MW of small hydro capacity
- 2019 200 MW of pumped storage capacity
- 2021 30 MW of a clean resource (such as wind).

The gas-fired plants represent the most economical means of addressing peak demand requirements, even after factoring in the cost of the B.C. carbon tax. Additional small hydro units, with some storage capacity, addresses capacity and energy requirements, and ensures continuous compliance with environmental goals for clean, renewable energy production. Pumped storage is a net energy user, requiring 1.3 MW of energy for each 1 MW of energy production. Yet, pumped storage is useful as an economical means of meeting peak hourly demand. The clean energy resource, while likely expensive and intermittent, helps meet environmental criteria, and could provide part of the off-peak energy required for the pump storage part of the portfolio.

This resource plan has not yet been approved by the regulator, and FortisBC expects to file updated information later this year. While the 2009 Resource Plan assumes (as required by the province's Energy Plan) that 50% of incremental resources will be met through demand-side management, stakeholder consultations on the plan elicited a preference for using conservation measures to meet future demand, as well as ensuring environmentally sound solutions, and minimization of transmission impacts. Nonetheless, stakeholders also expressed concern over rate impacts, and preferred less reliance on external energy markets.

We think the evolution from the conceptual status of a resource plan, to the reality of being included in FortisBC's BCUC-approved capital planning, will begin to proceed more quickly, as the plan calls for the first capacity addition, the proposed two small simple-cycle gas plants, to be added in 2014. We believe that, ultimately, a plan similar to what has been proposed in the 2009 Resource Plan will likely be adopted in the foreseeable future, as in our view, it achieves a sensible balance among the competing stakeholder concerns.

For now, we see the Resource Plan as close to neutral from a credit quality perspective. It would likely entail continued free cash flow deficits for much of the current decade, though we think this is a negligible concern, given the near-certainty that investments will be recovered in rates, and our view that adequate equity funding from a mix of retained earnings and Fortis Inc. contributions is also assured. What we view as moderate additional operating risk from the proposed new plants is counterbalanced by reduced exposure to domestic and import electricity market prices.

Ratios and Ratings

2009 financial results were healthy, repeating a pattern of modest but consistent earnings improvement since Fortis Inc. purchased FortisBC. Full-year 2009 earnings of $36 million were up 11% over 2008, as revenues (net of purchased power costs) rose 7.1%, while operating costs rose 3.3%. Depreciation rose 9.3%, reflecting asset additions from recent capital programs. FFO interest coverage rose marginally to 3.1x, from 3.0x in 2008, but consistent with the range of 2.8x to 3.1x achieved since 2005. (We adjust interest expense by adding back the non-cash AFUDC offset to the reported net interest expense, as shown in FortisBC's GAAP income statement.) As noted above, 2009 capex was $110 million. Free cash flow, after dividends of $15 million, was negative $56 million. After a $105 million bond issue, and Fortis Inc.'s injection of $10 million in common equity, debt to capitalization was 59.2%, virtually flat to last year's 59.1%, and consistent with the BCUC deemed equity capitalization of 40%. Given the higher planned capital spend, we expect slightly higher negative free cash flow in 2010, though otherwise, we expect ratios to be very similar to 2009. We anticipate a capital markets borrowing requirement in 2010 roughly in line with, or slightly higher than, the $105 million borrowing in 2009.

The DBRS rating on FortisBC has been unchanged since prior to Fortis Inc.'s acquisition of Aquila Networks Canada (which was split into FortisAlberta and FortisBC). We see a number of constructive changes in credit quality since the Fortis acquisition. First, the financial capacity of Fortis Inc. brings a clear improvement over the more limited resources of the former owner. As well, we see FortisBC as very clearly a core asset for Fortis Inc., and we view Fortis Inc.'s incentives and willingness to fund equity continuously, as required, as very strong. We also see the availability of Fortis Inc.'s depth of experience and expertise in operating regulated utilities as a considerable aid to FortisBC's management, in areas such as operations, planning, regulatory matters, financial reporting, and governance. Finally, we view the BCUC's recent ROE Decision as very constructive for FortisBC's credit quality, though not by itself enough to justify an upgrade.

While key financial ratios have not changed much since the acquisition, financial performance has been very stable, especially considering the effects on coverage and free cash flow of the large capital spending requirements. We expect this to continue. Operating measures such as safety, reliability, and customer satisfaction have all improved. We view these improved non-financial measures as material and beneficial to credit risk. In short, we think an upgrade is possible, though we see no indication in recent rating reports that DBRS is likely to upgrade in the near future.

Moody's upgraded FortisBC in June, 2007, though we still view the Moody's rating as very conservative. In its most recent opinion, Moody's set targets of FFO interest coverage "in excess of 3.0x" and FFO/ debt "of approximately 12%" as prerequisites for upgrade, in line with Moody's expectations for an "A" - rated global electric utility with "Low" business risk. We believe that Moody's adjusts interest expense by adding imputed interest on operating leases (for buildings and vehicles) and adding imputed interest on obligations related to the Brilliant Terminal Station agreement, which is treated as an operating lease for regulatory purposes, and as a capital lease under Canadian GAAP. FFO is also adjusted by adding the annual change in the unfunded pension liability. Interest expense excludes non-cash AFUDC earnings. While these adjustments have left FortisBC FFO interest coverage at 2.8x for the last three years, we think recent performance at FortisBC, perhaps aided going forward by the better ROE from the Generic Cost of Capital Decision, will bring FortisBC very close to crossing Moody's stated threshold for an upgrade to Baa1.

We believe that FortisBC will also have to improve its bank line availability, as Moody's views this aspect of its liquidity somewhat lacking. As $100 million of FortisBC's total $150 million of lines of credit mature on May 6th, 2010, we think it's possible that this concern may be at least partially addressed when new banking arrangements are announced, as we expect, in Q1 or Q2 this year.

While we do not see very significant spread improvement potential from one ratings upgrade, should both ratings be upgraded this year, we would expect a spread benefit of 10 bps or more from current levels. We remain very comfortable with FortisBC's prospects, and foresee no likelihood of a downgrade. Hence, we view FortisBC bonds as fair value at current indicative spread levels, and despite its current triple-B ratings, a comfortably low-risk and defensive component of a corporate bond portfolio.

## Fixed Income Research

**Robert Follis**, Managing Director
robert_follis@scotiacapital.com

**Roger Quick**, Director
roger_quick@scotiacapital.com

**Stephen Dafoe**, Director
stephen_dafoe@scotiacapital.com

**Graham Chubb**, Associate Director
graham_chubb@scotiacapital.com

**Francesco Sorbara**, Associate Director
francesco_sorbara@scotiacapital.com

**Scotia Plaza**
40 King Street West
68th Floor
Toronto, Ontario
M5W 2X6



Scotia Capital™

Products. Industry Knowledge. Relationships.

4. **All Prospectuses of Debt Offerings of the utility and/or its corporate parent within the last five years, if applicable:**

   - See enclosed for the prospectuses of FBC and
   - For Prospectuses of Debt Offerings by FBC's ultimate parent, Fortis Inc., see section 4 of FEI's Company Related Documents

   a. **Monthly (month end) spread data (market yield minus the yield on Government of Canada bond with similar time to maturity remaining) from 2006 to present date for a representative long-term bond issued by the utility**

   - See attached Historical Spread Data and Table in section 4 of FEI's Company Related Documents

      i. **The time to maturity of both the utility bond and the government bond**

      - See attached Historical Spread Data and Table in section 4 of FEI's Company Related Documents

      ii. **The trading liquidity of both bonds,**

      - See attached Average Trading Volumes analysis by RBC in section 4 of FEI's Company Related Documents

      iii. **The ratings on the bond for each quarter**

      - See section 2.b of FBC's Company Related Documents

      iv. **For the latest placement of bond, the spread over the corresponding Government bond yields, the current spread and the maturity date**

      - See attached Historical Spread Data and Table in section 4 of FEI's Company Related Documents

*No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities being offered under this short form prospectus have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws, and, subject to certain exceptions, may not be offered or sold within the United States or to or for the account or benefit of U.S. Persons. See "Plan of Distribution".*

***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the issuer at 5th Floor, 1628 Dickson Avenue, Kelowna, British Columbia, V1Y 9X1 (telephone (250) 469-8014), and are also available electronically at www.sedar.com. For the purpose of the Province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained without charge from the Secretary of the issuer at the above address and telephone number and is also available electronically at www.sedar.com.*

**SHORT FORM PROSPECTUS**

*New Issue* **June 22, 2007**

FORTISBC

# FortisBC Inc.

## $105,000,000

## 5.90% Senior Unsecured Debentures due July 4, 2047

The 5.90% senior unsecured debentures due July 4, 2047 (the "Debentures") offered hereby (the "Offering") are being issued by FortisBC Inc. ("FortisBC" or the "Corporation"), whose head and registered office is located at 5th floor, 1628 Dickson Avenue, Kelowna, British Columbia, V1Y 9X1. Interest on the Debentures will accrue at a rate of 5.90% per annum and will be payable semi-annually in arrears in equal instalments on January 4 and July 4 in each year to and including the maturity date, commencing on January 4, 2008. The Debentures will mature on July 4, 2047. The Corporation may redeem some or all of the Debentures at any time at a price equal to the greater of the Canada Yield Price (as defined herein) and par, plus accrued and unpaid interest to but excluding the date fixed for redemption. The Debentures will be direct unsecured obligations of the Corporation and will rank equally and rateably with all other present and future unsecured senior obligations of the Corporation. See "Details of the Offering".

**The Debentures rank behind the Corporation's existing senior secured debentures in an outstanding principal amount of $45.25 million, which are secured by a first fixed and floating charge against all of the assets of the Corporation. See "Risk Factors — Credit Risk and Prior Ranking Indebtedness". The Debentures will not be guaranteed by Fortis Inc. or any other company.**

**There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this short form prospectus. This may affect the prices of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures, and the extent of issuer regulation. See "Risk Factors — Lack of Public Market for Debentures" and "Plan of Distribution".**

**An investment in the Debentures involves certain risks that should be considered by a prospective purchaser. See "Risk Factors".**

## Price: 99.863% per Debenture

**Based on the price to the public and the prescribed rate of interest for the Debentures, the effective yield to maturity is 5.909% per annum.**

| | Price to the Public | Underwriters' Fee(1) | Net Proceeds to the Corporation(2) |
|---|---|---|---|
| Per $1,000 principal amount | $998.63 | $9.00 | $989.63 |
| Total | $104,856,150 | $945,000 | $103,911,150 |

Notes:

(1) The Underwriters (as defined below) will be paid a fee of 0.90% of the principal amount of the Debentures by the Corporation.

(2) Before deduction of the expenses of the Offering estimated to be $400,000 which, together with the Underwriters' fee, will be paid by the Corporation. See "Use of Proceeds" and "Plan of Distribution".

Scotia Capital Inc., CIBC World Markets Inc. and National Bank Financial Inc. (the "Underwriters"), as principals, conditionally offer the Debentures, subject to prior sale, if, as and when issued by the Corporation and accepted by the Underwriters in accordance with the conditions contained in the underwriting agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Underwriters by Stikeman Elliott LLP.

**Each of the Underwriters is an affiliate of a Canadian chartered bank that is currently a lender to the Corporation under credit facilities in connection with the Corporation's ongoing working capital and capital expenditure requirements. A portion of the net proceeds from the sale of Debentures offered hereby will be used to repay certain indebtedness owed to these banks. Consequently, the Corporation may be considered to be a "connected issuer" of the Underwriters within the meaning of applicable securities legislation. See "Plan of Distribution".**

Subscriptions for the Debentures will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will take place on or about July 4, 2007, or such other date as the Corporation and the Underwriters may agree, but not later than August 3, 2007. At the closing of the Offering, a global book-entry only certificate evidencing the Debentures will be delivered to, and registered in the name of, CDS Clearing and Depository Services Inc. ("CDS") or its nominee. Registration of interests in, and transfers of, Debentures will be made only through the clearing, depository and entitlement services of CDS. See "Details of the Offering".

## TABLE OF CONTENTS

| | | | |
|---|---|---|---|
| FORWARD-LOOKING INFORMATION | 2 | RISK FACTORS | 18 |
| DOCUMENTS INCORPORATED BY REFERENCE | 2 | CANADIAN FEDERAL INCOME TAX CONSIDERATIONS | 23 |
| PROSPECTUS PRESENTATION | 3 | ELIGIBILITY FOR INVESTMENT | 24 |
| THE CORPORATION | 3 | LEGAL MATTERS | 24 |
| RECENT DEVELOPMENTS | 4 | AUDITORS AND TRUSTEE | 25 |
| CAPITALIZATION | 4 | PURCHASERS' STATUTORY RIGHTS | 25 |
| DETAILS OF THE OFFERING | 5 | AUDITORS' CONSENT | 26 |
| RATINGS | 16 | GLOSSARY OF TERMS | 27 |
| EARNINGS COVERAGE RATIOS | 17 | CERTIFICATE OF FORTISBC INC | C-1 |
| USE OF PROCEEDS | 17 | CERTIFICATE OF THE UNDERWRITERS | C-2 |
| PLAN OF DISTRIBUTION | 17 | | |

## FORWARD-LOOKING INFORMATION

Prospective investors should be aware that this short form prospectus and the information incorporated herein by reference include forward-looking information within the meaning of applicable securities laws ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information in this short form prospectus and the information incorporated herein by reference include statements relating to the Corporation's business and anticipated results, trends, developments, earnings growth and capital project expenditures. The forecasts and projections that make up the forward-looking information are based on estimates and assumptions, which are subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, regulatory approval and rate orders, electricity demand, weather and natural disasters, equipment breakdown, operating and maintenance risk, interest rates, capital resources, credit risk and prior ranking indebtedness, labour relations, environmental matters, First Nations land matters, underinsured and uninsured losses, power supply contract matters, weather related demand loss, permits, climate change, credit ratings, market value fluctuation, lack of public markets for the Debentures and other risks described in this short form prospectus under the section heading "Risk Factors". All forward-looking information in this short form prospectus and the information incorporated herein by reference is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

## DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of FortisBC listed below and filed with the securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this short form prospectus:

(a) annual information form dated March 8, 2007;

(b) audited consolidated financial statements for the years ended December 31, 2006 and 2005, together with the notes thereto and the auditors' report thereon;

(c) management's discussion and analysis of financial condition and results of operations for the years ended December 31, 2006 and 2005;

(d) unaudited consolidated financial statements for the three month period ended March 31, 2007, together with the notes thereto; and

(e) management's discussion and analysis of financial condition and results of operations for the three month period ended March 31, 2007.

Any document of the type referred to in the preceding paragraph, any material change reports (excluding confidential material change reports), any business acquisition reports and any other document required to be incorporated by reference in a short form prospectus under the applicable securities laws of the provinces of Canada and filed by the Corporation with the securities commissions or similar authorities in each of the provinces of Canada after the date of this short form prospectus, and before the termination of the Offering, are deemed to be incorporated by reference into this short form prospectus.

**Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein, or in any other subsequently filed document that is also incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.**

**Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.** Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at 5th Floor, 1628 Dickson Avenue, Kelowna, British Columbia, V1Y 9X1 (telephone (250) 469-8014). These documents are also available through the Internet on the Canadian System for Electronic Document Analysis and Retrieval ("SEDAR") which can be accessed at www.sedar.com. The information contained on, or accessible through, this website is not incorporated by reference into the short form prospectus and is not, and should not be considered to be, a part of the short form prospectus, unless it is explicitly so incorporated. For the purpose of the Province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained without charge from the Secretary of the Corporation at the above mentioned address and telephone number.

## PROSPECTUS PRESENTATION

For an explanation of certain terms and abbreviations used in this short form prospectus, reference is made to the "Glossary of Terms". All references to dollars or "$" are to Canadian dollars unless otherwise noted.

## THE CORPORATION

FortisBC is an integrated, regulated electric utility, which generates, transmits and distributes electricity within its service territory in the southern interior of British Columbia. As at December 31, 2006, FortisBC had approximately 152,000 direct and indirect customers, including residential, commercial, industrial and wholesale customers in the cities and rural regions of its service area. The Corporation has been in continuous operation since 1897. The Corporation owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets.

FortisBC is regulated by the British Columbia Utilities Commission (the "BCUC"). The Corporation's rates are set within a framework that combines cost of service and performance-based regulation. Regulation of FortisBC provides for recovery of approved and prudently-incurred operating costs, power purchase costs, capital expenditures and taxes, while also providing for an investment return, which includes a return on capital in accordance with established common equity return methodologies and a deemed capital structure.

As at December 31, 2006, FortisBC had total assets of $815.0 million and a depreciated rate base of approximately $713.0 million. For the year ended December 31, 2006, FortisBC had revenues of $207.6 million and net income of $26.5 million.

FortisBC is an indirect wholly-owned subsidiary of FortisWest Inc., which in turn is a wholly-owned subsidiary of Fortis Inc., a diversified international utility holding company with investments in distribution, transmission and generation utilities as well as real estate and hotel operations. The Debentures are not guaranteed by Fortis Inc. or FortisWest Inc.

## RECENT DEVELOPMENTS

On May 14, 2004, a syndicate of Canadian chartered banks made available to the Corporation an operating credit facility for its general working capital and capital expenditure requirements. The operating credit facility was amended and restated on May 12, 2005 and was subsequently amended on May 5, 2006 and May 8, 2007 (collectively, the "Amended and Restated Credit Facility"). The Amended and Restated Credit Facility is comprised of a $50.0 million, three-year revolving facility maturing on May 12, 2010 ("Facility A") and a $100.0 million, 364-day revolving facility maturing May 8, 2008 ("Facility B"). At any time not more than 90 days and not less than 60 days prior to the date which is two years prior to the then Facility A maturity date, the Corporation may request an extension of the maturity date for Facility A for a further period of 364 days and if the request for extension is not granted, all amounts outstanding under Facility A, together with all accrued and unpaid interest and fees, become due on the Facility A maturity date. Similarly, at any time not more than 90 days and not less than 60 days prior to the then current Facility B maturity date, the Corporation may request the lenders to extend the term for an additional 364 days and if the request for extension is not granted, Facility B will automatically convert into a non-revolving term credit facility that will mature six months from that date. The Amended and Restated Credit Facility also allows the Corporation to request that the lenders provide up to $50.0 million of additional financing under Facility A or Facility B or a combination of the two facilities. Borrowings under the Amended and Restated Credit Facility may be made in Canadian dollars and bear interest based on the prime rate or certificate of deposit offered rate for bankers' acceptances plus, in each case, a margin based on the Corporation's debt ratings provided by credit rating agencies. The Amended and Restated Credit Facility is also available to support letters of credit. Obligations of the Corporation under the Amended and Restated Credit Facility are not guaranteed by Fortis Inc. or FortisWest Inc.

On May 1, 2007, Philip Hughes resigned as a director of the Corporation and Randall Jespersen was appointed as a director. Mr. Jespersen is the President of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., regulated natural gas distribution utilities operating in British Columbia that were recently acquired by Fortis Inc.

On April 20, 2007, Kootenay River Power Corporation, a non-operating subsidiary of the Corporation without any material assets or liabilities, was dissolved.

## CAPITALIZATION

The following table sets out the capitalization of the Corporation on a consolidated basis as at December 31, 2006 and as at March 31, 2007, both actual and adjusted to reflect the issue and sale of the Debentures and the use of proceeds derived therefrom. See "Use of Proceeds". This table should be read in conjunction with the Corporation's consolidated financial statements as at and for the year ended December 31, 2006 and as at and for the three month period ended March 31, 2007, together with the accompanying notes, incorporated by reference in this short form prospectus.

| | As of December 31, 2006 | As of March 31, 2007 | As of March 31, 2007 after giving effect to the Offering |
|---|---|---|---|
| | (dollars in thousands) | | |
| **Short Term Debt** | | | |
| Operating credit facility — Facility B(1)(2) | $ — | $ — | $ — |
| Overdraft facility and outstanding cheques(3) | 26,038 | 2,224 | — |
| Affiliate demand notes(1) | — | 31,000 | — |
| Total short term debt | $ 26,038 | $ 33,224 | $ — |
| **Long Term Debt(4)** | | | |
| Secured debentures | $ 45,250 | $ 45,250 | $ 45,250 |
| Term operating credit facility — Facility A(2) | 20,968 | 11,975 | — |
| Walden Power Partnership indebtedness | 5,817 | 5,663 | 5,663 |
| Unsecured debentures | 340,000 | 340,000 | 445,000 |
| | 412,035 | 402,888 | 495,913 |
| Deferred financing costs(5) | $ — | $ (3,629) | $ (4,974) |
| Total long term debt | $412,035 | $399,259 | $490,939 |
| **Total Debt** | $438,073 | $432,483 | $490,939 |
| **Shareholder's Equity** | | | |
| Common shares | $151,851 | $151,851 | $151,851 |
| Retained earnings | 145,812 | 154,251 | 154,251 |
| **Total Shareholder's Equity** | $297,663 | $306,102 | $306,102 |
| **Total Capitalization** | $735,736 | $738,585 | $797,041 |

Notes:

(1) On May 29, 2007, the affiliate demand notes were repaid with proceeds from draws on Facility B.

(2) From March 31, 2007 to June 13, 2007, the total indebtedness under Facility A and Facility B increased from $12.0 million to $66.0 million. Included in this increase is the $31.0 million affiliate demand note repayment described in note (1) above.

(3) The December 31, 2006 balance includes $4.5 million outstanding under a demand operating bank facility. This facility was cancelled in conjunction with the wind-up of Princeton Light and Power Company, Limited on January 1, 2007.

(4) Includes current portion of long term debt of approximately $1.4 million for both March 31, 2007 and December 31, 2006.

(5) Upon adoption on January 1, 2007, of the new accounting standards for financial instruments, the Corporation has recorded deferred financing costs as an offset to long term debt. As of December 31, 2006, the deferred financing costs were recorded as a deferred charge asset.

## DETAILS OF THE OFFERING

The Debentures will be issued under a trust indenture dated as of November 30, 2004 (the "Principal Indenture") between the Corporation and Computershare Trust Company of Canada, as trustee (the "Trustee"), as supplemented and amended by the first supplemental indenture dated as of November 10, 2005 (the "First Supplemental Indenture") and as to be supplemented by the second supplemental indenture (the "Second Supplemental Indenture") to be dated as of the date of closing (the "Closing Date"). The Principal Indenture as supplemented and amended by the First Supplemental Indenture, the Second Supplemental Indenture, and as from time to time supplemented and amended by further supplemental indentures, is herein called the "Indenture".

The following is a summary of the principal terms and conditions of the Debentures and of the Indenture. This summary does not purport to be complete and prospective investors are urged to read the Indenture in its entirety for the complete terms and conditions of the Debentures and the Indenture. Certain capitalized terms used in the following summary are defined under " — Definitions" below.

### Trust Indenture

The Indenture permits the issuance from time to time of an unlimited aggregate principal amount of debentures in one or more series. This short form prospectus qualifies the distribution of the Debentures, which will be issued in an aggregate principal amount of $105.0 million. Additional series of debentures may be issued from time to time pursuant to supplemental indentures in accordance with the terms and conditions of the Indenture.

The Corporation may increase at any time the aggregate principal amount of any outstanding series of debentures by issuing additional debentures of that series subject to any limitations as to the maximum principal amount of debentures of such series as set out in the Indenture. The aggregate principal amount of Debentures that may be issued is limited to the aggregate principal amount of Debentures being offered hereby.

**Interest Rate and Maturity**

The Debentures will be dated the Closing Date, will mature on July 4, 2047 and will bear interest at a rate of 5.90% per annum. Interest on the Debentures will be payable semi-annually in arrears in equal instalments on January 4 and July 4 in each year commencing on January 4, 2008. Assuming a Closing Date of July 4, 2007, the initial interest payment for the period from the Closing Date to January 4, 2008 will be $29.50 per $1,000 principal amount thereof. Principal, interest and premium, if any, will be payable in lawful money of Canada.

**Form of Debentures**

The Debentures will be issued in "book-entry only" form in minimum denominations of $1,000 and in integral multiples of $1,000 and beneficial interests therein must be purchased or transferred through participants ("Participants"), which includes securities brokers and dealers, banks and other financial institutions, who participate directly in the book-entry registration and book-based securities transfer system administered by CDS (or such other person who is designated in writing by the Corporation to act as depository for the Debentures). On the issue of the Debentures, the Corporation will cause a book-entry only global certificate evidencing the Debentures (a "Global Debenture") to be delivered to, and registered in the name of, CDS or its nominee. Except as described below, no purchaser of a beneficial interest in the Debentures will be entitled to a certificate or other instrument from the Corporation or CDS evidencing that purchaser's interest therein, and no holder of a beneficial interest in the Debentures will be shown on the records maintained by CDS except through a Participant. The ability of a holder having a beneficial interest in the Debentures outstanding in "book-entry only" form to pledge such interest or otherwise take action with respect to such interest (other than through a Participant) may be limited due to the lack of a physical certificate.

Debentures issued to investors in the United States will also be issued in book-entry only form in the manner described above and the Global Debenture representing such Debentures issued to investors in the United States will be subject to certain restrictions on transfer set forth therein and in the Indenture and will bear a legend regarding such restrictions as described in the Indenture.

None of the Corporation, the Underwriters, the Trustee nor any other Paying Agent, if any, will have any responsibility or liability for any aspects of the records relating to, or payments made by any depository or any Participant on account of the beneficial interests in, any Global Debenture.

The Debentures will be issued to beneficial owners in certificated form only if (a) CDS notifies the Corporation that it is unwilling or unable to continue to act as depository in connection with the relevant Global Debenture and the Corporation is unable to locate a qualified successor, (b) the Corporation determines that CDS is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global Debentures and the Corporation is unable to locate a qualified successor, (c) the Corporation executes and delivers to the Trustee a written order of the Corporation to the effect that all or a part of any Global Debenture is to be exchanged for Debentures in certificated form, (d) CDS ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Corporation is unable to locate a qualified successor, (e) the Corporation determines that the Debentures will no longer be held as book-entry only debentures through CDS, (f) after the occurrence of an Event of Default, CDS advises the Trustee that it received written notification from Participants, acting on behalf of beneficial owners representing, in the aggregate, more than 50% of the aggregate principal amount of outstanding debentures, that the continuance of the book-entry registration system in respect of the debentures is no longer in their best interests, or (g) the Corporation is required to do so by applicable law as determined by the Corporation.

**Transfer of Debentures**

Transfers of beneficial ownership of Debentures represented by a Global Debenture will be effected through the clearing, depository and entitlement services maintained by CDS for such Global Debenture (with respect to interests of Participants) and through the records of Participants (with respect to interests of persons other than Participants).

## Payment of Principal and Interest

Payments of principal, interest and premium, if any, on each Global Debenture will be made to CDS or its nominee, as the case may be, as registered holder of such Global Debenture. The Corporation will not withhold any amount from the payment of interest, premium or principal to any holder resident outside of Canada for the purposes of the *Income Tax Act* (Canada) unless required to do so by law. The Debentures make no provision for increased interest or payment of any other amount where the Corporation is required by law to withhold in respect of a holder resident outside of Canada.

## Ranking

The Debentures will be direct, senior, unsecured unsubordinated obligations of the Corporation, will rank *pari passu* with each other and any debentures of another series issued under the Indenture and with all other present and future unsecured and unsubordinated Indebtedness of the Corporation (except as to sinking fund provisions of different series of debentures, if applicable), and will have priority over all Subordinated Debt (irrespective of whether any such Subordinated Debt is secured or not). The Corporation has outstanding $45.25 million aggregate principal amount of three series of senior secured debentures (Series E, F and G) secured by a first fixed and floating charge against all of the assets of the Corporation, which were issued pursuant to the Trust Deeds (as hereinafter defined) and which rank prior to the Debentures. The Series E, F and G secured debentures mature on December 1, 2009, October 16, 2012 and August 28, 2023, respectively, and are guaranteed by FortisWest Inc. The Corporation is an indirect wholly-owned subsidiary of FortisWest Inc., which in turn is a wholly-owned subsidiary of Fortis Inc.

On November 30, 2004, $100 million aggregate principal amount of three series of senior secured debentures (Series H, I and J) issued pursuant to the Trust Deeds were converted to unsecured debentures. The unsecured debentures resulting from this conversion continue to be guaranteed by FortisWest Inc.

## Redemption

The Debentures will be redeemable, at the Corporation's option, in whole at any time or in part from time to time before maturity, on not less than 30 days' prior notice and not more than 60 days' prior notice, at a redemption price equal to the greater of the principal amount of the Debentures to be redeemed and the Canada Yield Price together, in each case, with accrued and unpaid interest to, but excluding, the redemption date. The term "Canada Yield Price" means the price in respect of the principal amount of the Debentures to be redeemed, calculated as of the Business Day immediately prior to the Business Day on which the Corporation gives a notice of redemption, or as of the date on which notice of acceleration is given or acceleration automatically occurs pursuant to the terms of the Indenture, equal to the net present value of all scheduled payments of interest and principal on such Debentures from the date of redemption or the date of acceleration (as the case may be) to the date of maturity of such Debentures using as a discount rate the sum of the Canada Yield on such Business Day or the date of such acceleration, as the case may be, plus 0.31%.

The term "Canada Yield" means, on any date, the yield to maturity on that date, compounded semi-annually and calculated in accordance with generally accepted financial practice, that a non-callable Government of Canada bond would bear if it were issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity approximately equal to the remaining term to maturity of the particular series of debentures in respect of which the Canada Yield Price is being determined. In calculating the Canada Yield for purposes of a redemption of any series of debentures, the Corporation will use the arithmetic average of the yields quoted at 10:00 a.m. (Vancouver time) on the relevant date by two major Canadian investment dealers selected by the Corporation in accordance with the Indenture.

Where less than all of the outstanding Debentures are to be redeemed, the Debentures to be redeemed generally will be selected on a *pro rata* basis by the Trustee.

## Purchase of Debentures for Cancellation

The Corporation will have the right to purchase the Debentures in the market, by tender or private contract, from time to time. Any Debentures purchased by the Corporation will be cancelled and not be reissued.

### Certain Covenants of the Corporation

The Indenture will contain, among other things, covenants and provisions applicable so long as any of the Debentures are outstanding, substantially to the following effect:

#### *Negative Pledge*

Except for Permitted Liens (which include the Liens in favour of the secured debentures outstanding under the Trust Deeds), the Corporation will not, and will ensure that no Subsidiary will, directly or indirectly, create, incur, assume or suffer to exist any Lien on any of its present or future property or assets or any income or profits therefrom, or assign or convey any right to receive income therefrom, to secure any Indebtedness, unless (a) if such Lien secures Indebtedness that ranks in priority to or *pari passu* with the Debentures, the Debentures are secured on an equal and rateable basis with the obligations so secured until such time as such Indebtedness is no longer secured by a Lien, or (b) if such Lien secures Subordinated Debt, any such Lien will be subordinated to a Lien granted to the Debenture holders to the same extent as such Subordinated Debt is subordinated to the Debentures.

In addition to the Permitted Liens, the Corporation or any Subsidiary may create, incur, assume or suffer to exist any Lien that secures an aggregate amount of Indebtedness which, together with Indebtedness of any Subsidiary (whether or not secured) other than (a) Indebtedness of Subsidiaries which is Non-Recourse Debt and (b) unsecured Indebtedness of a Subsidiary that has irrevocably and unconditionally guaranteed the obligations of the Corporation under the Debentures and which unsecured Indebtedness is subordinate to or *pari passu* with the obligations of such Subsidiary under such guarantee, does not at any time exceed 5% of Consolidated Net Worth.

#### *Limitations on Funded Obligations*

The Corporation will not, and will ensure that no Subsidiary will, incur, issue, assume, guarantee or otherwise become liable directly or indirectly for any Funded Obligation, unless (a) after giving effect thereto, the aggregate principal amount of Consolidated Funded Obligations does not exceed 75% of Total Consolidated Capitalization, calculated on a *pro forma* basis, and (b) no Default or Event of Default shall have occurred and be continuing under the Indenture at the time of, or will occur as a consequence of, such Funded Obligation having been incurred, issued, assumed, guaranteed or otherwise becoming a liability of the Corporation or any Subsidiary. For purposes of such calculation, Consolidated Funded Obligations will not include Financial Instrument Obligations entered into for risk management purposes in the ordinary course of and related to the business of the Corporation and its Subsidiaries and not simply as a matter of speculation and having an aggregate net amount due or accruing due thereunder, determined by marking each such obligation to market at the time of determination, of not more than $30 million but, for greater certainty, shall include the aggregate net amount due or accruing due in excess of $30 million under all such Financial Instrument Obligations. Solely for this purpose, all Indebtedness incurred, issued, assumed or guaranteed by, or otherwise becoming a liability of, a Subsidiary (but, for greater certainty, excluding trade payables of such Subsidiary incurred in the ordinary course of such Subsidiary's business) shall be deemed to be a Funded Obligation of such Subsidiary regardless of the actual term of such Indebtedness and regardless of whether or not such Indebtedness of such Subsidiary is Subordinated Debt.

#### *Limitations on Subsidiary Funded Obligations*

The Corporation will ensure that no Subsidiary will issue any Funded Obligations, other than (a) Funded Obligations that are Non-Recourse Debt and (b) if the Subsidiary is directly or indirectly wholly-owned by the Corporation, Funded Obligations to the Corporation.

#### *Limitations on Successor Corporations*

The Corporation will not enter into any transaction or series of transactions in which all or substantially all of its property and assets would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless (a) either the Corporation is the surviving entity, or the entity formed by the amalgamation or consolidation or into which the Corporation is merged, or that acquires all or substantially all of the property and assets of the Corporation, is a corporation, partnership or trust organized and validly existing under the laws of Canada or any of its provinces or territories and expressly assumes all the obligations of the Corporation under the Indenture and any supplemental indentures (a "Successor Entity") and (b) no Default or Event of Default is continuing or will occur as a result of such transaction.

***Limitation on Financial Instrument Obligations***

The Corporation will not enter into any Financial Instrument Obligation except for risk management purposes in the ordinary course of and related to the business of the Corporation and its Subsidiaries and not simply as a matter of speculation.

***Restriction on Business***

The Corporation (directly or through its Subsidiaries) will not engage in any business not regulated by the BCUC, other than a business related to a business regulated by the BCUC.

***Related Party Transactions***

The Corporation will not, and will ensure that no Subsidiary will, directly or indirectly, engage in any transaction with any affiliate on terms that are less favourable to the Corporation or such Subsidiary than with an unrelated third party; provided, however, that this restriction shall not apply in respect of any transfer by the Corporation to any subsidiary of Fortis Inc. of all or any part of West Kootenay Power Ltd., ESI Power-Walden Corporation Ltd. or the Walden Power Partnership. West Kootenay Power Ltd. holds a 0.001% interest in the Walden Power Partnership. ESI Power-Walden Corporation owns certain of the assets used by the Walden Power Partnership in the operation of the 16 megawatt Walden power plant.

***Subsidiaries***

The Corporation will create and maintain Subsidiaries only for the purpose of carrying on a business or undertaking that is related to or ancillary to the business of the Corporation. In addition, the Corporation will not (a) directly or indirectly, guarantee or secure or become contingently liable for in any manner any Indebtedness of a Subsidiary, other than by way of delivery of letters of credit or guarantees from the Corporation in favour of an independent system operator or as it may otherwise be directed by the BCUC in connection with any regulated business of the Subsidiary, in which event the face amount of such letter of credit or equivalent amount of guarantee (regardless of the actual term thereof) will be included as a Funded Obligation of the Corporation for all purposes of the Indenture or (b) provide a loan to a Subsidiary unless such Subsidiary is a wholly-owned direct or indirect Subsidiary of the Corporation. Notwithstanding the foregoing, the Corporation may guarantee or secure or become contingently liable for the Walden Indebtedness (as hereinafter defined).

**Events of Default**

The occurrence of any one or more of the following will constitute an Event of Default under the Indenture:

(a) if the Corporation defaults in payment of any principal or premium, if any, on any debentures when the same becomes due and payable (including, for greater certainty, a default in payment relating to a redemption of all or part of such debentures) and such default continues for a period of five Business Days;

(b) if the Corporation defaults in payment of any interest on any debentures when the same becomes due and payable and such default continues for a period of 30 days;

(c) if the Corporation fails to comply with its covenant described under "— Limitations on Successor Corporations" above;

(d) if the Corporation neglects to observe or perform in any material respect any covenant or condition (other than those referred to in paragraphs (a), (b) and (c) above) contained in the Indenture or any debenture on its part to be observed or performed and, after notice in writing has been given by the Trustee to the Corporation (which notice the Trustee may, in its discretion, independently provide and shall provide upon receipt of a Holders' Request) specifying such default and requiring the Corporation to remedy such default, the Corporation fails to remedy such default within a period of 60 days unless the Trustee, having regard to the subject matter of the default, agrees to give the Corporation a longer period of time within which to cure such default, and in such event, within the period agreed to by the Trustee;

(e) if any representation or warranty made by the Corporation in the Indenture, in any debenture or in any supplemental indenture or in any document or certificate provided to the Trustee or the holders of debentures pursuant to the provisions of the Indenture or a debenture is proven to be incorrect in any material respect, unless such incorrect representation or warranty is capable of being corrected and the Corporation cures such default within a period of 60 days following the receipt of written notice from the Trustee (which notice the

Trustee may, in its discretion, independently provide and shall provide upon receipt of a Holders' Request) specifying the incorrect representation and warranty, unless the Trustee, having regard to the subject matter of the breach, agrees to give the Corporation a longer period of time within which to cure such default, and in such event, within the period agreed to by the Trustee;

(f) if at any time a default is made by the Corporation or any Subsidiary, whether as primary obligor or guarantor or surety, with respect to any Indebtedness (excluding amounts due to the holders under the debentures and, with respect to the Walden Power Partnership, excluding the Walden Indebtedness), where the aggregate principal amount of such Indebtedness exceeds an amount equal to 5% of Consolidated Net Worth at such time and (i) if the default is a payment default, such default continues to exist beyond any applicable cure period; provided that if the payment obligation to which the default relates is accelerated, then the default will constitute an Event of Default immediately following such acceleration and (ii) if the default is not a payment default, then as a result of the default and the passing of any applicable cure period, the maturity of the obligation is accelerated; provided that, in each case, if the default is cured prior to acceleration of the debentures, then the Event of Default will be deemed to have been cured;

(g) if the Corporation becomes insolvent, makes any assignment in bankruptcy or makes any other assignment for the benefit of creditors, makes any proposal under the *Bankruptcy and Insolvency Act* (Canada) or any comparable law, seeks relief under the *Companies' Creditors Arrangement Act* (Canada), the *Winding Up and Restructuring Act* (Canada) or any other bankruptcy, insolvency or analogous law, has a trustee, receiver, receiver and manager, interim receiver, custodian, sequestrator or other person with similar powers appointed over all or any substantial portion of its assets, or files a petition or otherwise commences any proceeding seeking any reorganization, arrangement, composition or readjustment under any applicable bankruptcy, insolvency, moratorium or other similar law affecting creditors' rights or consents to, or acquiesces in, the filing of such a petition;

(h) if a proceeding is instituted against the Corporation with respect to the appointment of a liquidator, trustee in bankruptcy, custodian, receiver or receiver and manager or other person with similar powers with respect to the Corporation or any material part of the property of the Corporation and such proceeding has not been dismissed, discharged, stayed or restrained within 60 days of the institution thereof, provided that during such 60-day period the proceeding is being defended in good faith by the Corporation and the position of the holders of debentures is not being prejudiced in any material respect;

(i) if an encumbrancer takes possession of property of the Corporation or Subsidiaries that constitutes a substantial part of the property of the Corporation considered on a consolidated basis, or any execution is levied or enforced upon property that constitutes a substantial part of the property of the Corporation considered on a consolidated basis, which execution remains unsatisfied for such period of time as would permit such property to be sold thereunder unless such execution is in good faith being contested by the Corporation or its Subsidiaries and enforcement and any other action or proceeding relating to such execution has been stayed pending the outcome of such contest; or

(j) the rendering at any time by a court or courts of competent jurisdiction of a final judgment or judgments against the Corporation or any Subsidiary (other than a Subsidiary whose only Indebtedness is Non-Recourse Debt and whose only material asset is the property to which such Non-Recourse Debt has recourse in the event of a default in its repayment) in an aggregate amount in excess of the lesser of (i) $50.0 million and (ii) 10% of the Consolidated Net Worth of the Corporation at such time, which judgment or judgments are not subject to any further appeal by the Corporation or such Subsidiary or in respect of which the applicable period in which an appeal may be commenced by the Corporation or such Subsidiary has expired and which judgment or judgments remain unpaid, unvacated or unstayed for a period of 60 days.

Upon the occurrence of an Event of Default that is continuing, the Trustee may, in its discretion and will, upon receipt of a Holders' Request, declare the principal of and interest on all debentures then outstanding and any other monies payable under the Indenture to be due and payable immediately. Notwithstanding the preceding sentence, if an Event of Default occurs and is continuing pursuant to paragraph (g) or (h) above, the principal of and interest on the debentures then outstanding and any other monies payable under the Indenture will be due and payable immediately without demand or notice of any kind. Upon such acceleration, the Corporation shall forthwith pay to the Trustee for the benefit of the holders of debentures the principal of, and accrued and unpaid interest, and premium, if any (calculated as if such debentures were being redeemed and the redemption date was the date such amounts become due and payable), together with interest at the rate borne by the debentures on such principal, interest and such other monies from the date of such declaration until payment is received by the Trustee.

**Modification and Waiver**

The Indenture will require the consent of the holders of 100% of the outstanding principal amount of the debentures of a particular series to amend the terms of the debentures of such series which affect the interest rate, the timing, currency, amount or other terms relating to the payment of interest, principal, premium or the applicable redemption price or the terms of repayment, redemption or maturity of such series of debentures. The Indenture will require the consent of the holders of 100% of the outstanding principal amount of all debentures to amend the percentage required to make amendments or waivers to other terms and conditions of the Indenture. The consent of the holders of at least 66⅔% of the outstanding principal amount of all debentures then outstanding or 66⅔% of the principal amount of debentures represented at a meeting of the holders of debentures at which a quorum is present will be required to amend or waive other terms and conditions, including a waiver of any Default or Event of Default and a cancellation of any declaration to make all amounts outstanding immediately due and payable.

**Trustee**

Computershare Trust Company of Canada will serve as the trustee, registrar and paying agent under the Indenture.

**Governing Law**

The Debentures and the Indenture will be governed by and construed in accordance with the laws of the Province of British Columbia and the federal laws of Canada applicable therein.

**Definitions**

The following defined terms used in this section of this short form prospectus will be defined in the Indenture substantially as set out below:

*"BCUC"* means the British Columbia Utilities Commission, an independent quasi-judicial regulatory agency that operates under and administers the *Utilities Commission Act* (British Columbia), and is responsible for, among other things, the regulation of British Columbia's electricity industry and includes any successor body or agency thereto;

*"Brilliant Terminal Agreement"* means the Brilliant Terminal Station Facilities Interconnection and Investment Agreement entered into with the Columbia Power Corporation and the Columbia Basin Trust in 2002 relating to the engineering, design, procurement, construction, maintenance and ownership of a common substation near the Brilliant Plant;

*"Business Day"* means a day, other than a Saturday or Sunday, on which banks in Toronto, Ontario, Vancouver, British Columbia and Kelowna, British Columbia are generally open for business and are not authorized or obligated by law to close;

*"Capital Lease Obligation"* means the obligation of the Corporation or a Subsidiary, as lessee, to pay rent or other payment amounts under a lease or similar arrangement of real or personal property which is required to be classified and accounted for as a capital lease or liability in accordance with GAAP, and for purposes of the Indenture the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with GAAP; provided that the Brilliant Terminal Agreement and any other lease or similar arrangement in respect of real or personal property that the Corporation or any of its Subsidiaries is not required to classify and account for as a Capital Lease Obligation pursuant to an order or similar authorization of the BCUC shall not be classified as a Capital Lease Obligation for the purposes of the Indenture;

*"Common Shares"* means shares of any class or classes of the share capital of a corporation or securities representing ownership interests in any person other than a corporation, the rights of the holders of which to participate in the distribution of assets upon the voluntary or involuntary liquidation, dissolution or wind-up of such corporation or other person are not restricted to a fixed sum or to a fixed sum plus accrued dividends or other periodic distributions;

*"Consolidated Funded Obligations"* means the aggregate amount of Funded Obligations of the Corporation and its Subsidiaries determined on a consolidated basis in accordance with GAAP;

*"Consolidated Net Worth"* means the Shareholders' Equity of the Corporation and its Subsidiaries determined on a consolidated basis in accordance with GAAP;

*"Contingent Liability"* means any agreement, undertaking or arrangement by which any person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Indebtedness of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any person's obligation under any Contingent Liability shall (subject to any limitation set forth therein) be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

*"Debentures"* means the 5.90% Senior Unsecured Debentures due July 4, 2047, and *"debentures"* means debentures of any series issued and outstanding under the Indenture from time to time;

*"Default"* means any event which, after giving notice, or passage of time, or both, would constitute an Event of Default;

*"Event of Default"* means any of the events described under "— Events of Default" above;

*"Financial Instrument Obligations"* means, with respect to any person, obligations arising under any agreement relating to derivatives, including:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time;

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity; or

(d) any other derivative transaction, including any option to enter into any of the foregoing, or any combination of the foregoing,

provided that the amount of any Financial Instrument Obligation is the net amount due or accruing due under the agreement governing such obligation, determined by marking such obligation to market at the time of determination in accordance with its terms;

*"Funded Obligations"* means, as at any date, with respect to the Corporation or a Subsidiary, all Indebtedness created, assumed or guaranteed other than Subordinated Debt and all Indebtedness which matures by its terms on, or is renewable at the option of the debtor to, a date not more than 18 months after the date of the original creation, assumption or guarantee thereof;

*"GAAP"* means, at any time, generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants or any successor body, as modified from time to time by regulatory directives of the BCUC;

*"Head Office Lease"* means the lease made as of September 29, 1993 between Aetna Life Insurance Company of Canada, as landlord, and the Corporation;

*"holder"* means, when used with respect to any debenture at any particular time, the person in whose name the debenture is registered at such time in the register of debentures maintained by the Trustee;

*"Holders' Request"* means an instrument requesting the Trustee to take or refrain from taking some action or proceeding specified therein, signed in one or more counterparts by the holder or holders representing not less than 25% of the total principal amount of all debentures, or if applicable, any series of debentures, then outstanding;

*"Indebtedness"* means, with respect to a person, without duplication:

(a) all obligations of such person in respect of borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments, but excluding (i) Preferred Securities issued by such person, (ii) trade payables of such person incurred in the ordinary course of business and (iii) Prudential and Credit Support Obligations;

(b) all Financial Instrument Obligations (other than Prudential and Credit Support Obligations);

(c) all obligations issued or assumed by such person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(d) all Purchase Money Obligations and Capital Lease Obligations; and

(e) all Contingent Liabilities of such person in respect of any of the foregoing;

*"Liens"* means, with respect to any property or assets, any security interest, mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge, assignment, adverse claim, defect of title in, on or of such property or assets, the interest of a vendor or a lessor under any conditional sales contract, hire-purchase agreement, chattel mortgage, title retention agreement or capital lease (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such property or assets and any other arrangement having the effect of providing security;

*"Non-Recourse Debt"* means, with respect to a Subsidiary, any Indebtedness incurred by a Subsidiary for the purpose of acquiring, repairing, altering, constructing or developing any real or tangible personal property and in respect of which recourse, in the event of a default in the repayment of such Indebtedness, is limited to such property (including all rights and benefits related to or arising out of such property) and includes any extension, renewal or refunding of any such Indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

*"Paying Agent"* means any person, which may include the Trustee, authorized by the Corporation to pay the principal of and premium, if any, and interest on any debentures on behalf of the Corporation;

*"Permitted Financial Instrument Obligations"* means Financial Instrument Obligations that the Corporation is permitted to enter into pursuant to the Indenture for risk management purposes in the ordinary course of and related to the business of the Corporation and its Subsidiaries and not simply as a matter of speculation;

*"Permitted Liens"* means, as at any particular time, any of the following Liens:

(a) Liens for Taxes, rates, assessments or governmental charges or levies which are not due or delinquent or which are due and delinquent but the validity of which is being contested in good faith and in respect of which appropriate provision is made in the Corporation's consolidated financial statements in accordance with GAAP;

(b) Liens imposed by law (such as builders', carriers', warehousemen's, landlords', mechanics' and materialmen's Liens) which arise in the ordinary course of business and relate to obligations not yet due or delinquent or the validity or amount of which are being contested in good faith and in respect of which adequate provision for payment has been made; any Lien arising out of judgments or awards with respect to which the Corporation or a Subsidiary is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review (provided no Event of Default has resulted therefrom); or undetermined or inchoate Liens incidental to current operations which have not at such time been filed pursuant to law against the Corporation or any Subsidiary or which relate to obligations not due or delinquent;

(c) any encumbrance affecting real property, such as easements, title irregularities, encroachments, rights-of-way, servitudes or other encumbrances of a nature similar to the foregoing, granted to or reserved by other persons which do not in the aggregate materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary and mortgages of and other Liens against any such encumbrance;

(d) the rights reserved to or vested in municipalities or governmental or other public authorities (whether by statutory provisions or otherwise) to terminate leases, licences, franchises, grants or permits or to require annual or other periodic payments as a condition of the continuance thereof;

(e) reservations in any original grants from the Crown of any land or interest therein, statutory exceptions to title, and reservations of mineral rights (including coal, oil and natural gas) in any grants from the Crown or from any other predecessors in title;

(f) security given by the Corporation or any Subsidiary to public utilities or to any municipalities or governmental or other public authorities when required by the utility, municipality, governmental or other public authority in connection with the supply of services or utilities to the Corporation or such Subsidiary, or security otherwise required by the BCUC to be given by the Corporation or any Subsidiary to the BCUC or any other person;

(g) plans of subdivision, site plans, municipal agreements, zoning or other restrictive covenants affecting the use of real property or interests therein provided that such plans, agreements, zoning or covenants are complied with and do not in the aggregate materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary;

(h) Liens or good faith deposits arising in connection with bids, tenders or contracts entered into in the ordinary course of business;

(i) deposits of cash or securities in connection with any Lien referred to in this definition which is being contested or otherwise sought to be removed in good faith by the Corporation or any Subsidiary;

(j) rights and interests created by notice registered by any department of highways or any similar authority with respect to proposed highways, which do not materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary;

(k) certificates of pending litigation that may be registered against any real property or interests therein of the Corporation or a Subsidiary in respect of any action or proceeding against the Corporation or such Subsidiary, but with respect to which action or proceeding no judgment, award or attachment against the Corporation or such Subsidiary has been granted or made and which the Corporation or such Subsidiary is defending in good faith and in respect of which appropriate provision is made in the Corporation's consolidated financial statements in accordance with GAAP;

(l) any Lien in connection with the granting by the Corporation in the ordinary course of its business of any lease, sub-lease, tenancy or right of occupancy to any person in respect of property owned or leased by the Corporation or any Subsidiary; any Lien or right of distress reserved in or exercisable under any lease for rent and for compliance with the terms of that lease including, without limitation, Liens under the terms of the Brilliant Terminal Agreement and the Head Office Lease;

(m) Purchase Money Security Interests and any Lien which is created, issued or assumed by the Corporation or any Subsidiary to secure a Capital Lease Obligation;

(n) any Lien on a property or asset acquired by the Corporation or any Subsidiary that secures the obligations of a person, whether or not that obligation is assumed by the acquiring person, which Lien exists before and at the time that property or asset is acquired and which (i) was not incurred in contemplation of, or as a result of, that property or asset being acquired and (ii) is not applicable to the Corporation or any Subsidiary or the properties or assets of the Corporation or any Subsidiary other than the property or asset so acquired;

(o) any deposit, margin account or similar Lien to secure obligations under Permitted Financial Instrument Obligations;

(p) any Lien granted by a Subsidiary in favour of the Corporation and any Lien on an asset created or assumed by a Subsidiary to secure Non-Recourse Debt of such Subsidiary in respect of such asset;

(q) any Lien granted by the Corporation to secure Indebtedness payable on demand or maturing within 18 months of the date that such Indebtedness is incurred or of the date of any renewal or extension of such Indebtedness;

(r) any Lien granted by the Corporation with the prior written consent of the Trustee or the holders of the debentures, acting reasonably;

(s) the Trust Deeds Liens and the Walden Liens; and

(t) Liens in favour of operators of other facilities in connection with shared facilities and transmission assets, which facilities and transmission assets are subject to regulation by the BCUC;

*"Preferred Securities"* means (a) Securities which on the date of issue thereof by a person (i) have a term to maturity of more than 30 years, (ii) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of such person outstanding on such date, (iii) entitle such person to satisfy the obligation to pay the principal or face amount thereof by issuing Common Shares, (iv) entitle such person to defer the payment of interest thereon for more than four years without causing an event of default to occur and (v) entitle such person to satisfy the obligation to make payments of

interest thereon by issuing Common Shares and (b) shares of any class in the capital of a corporation or Securities representing ownership interests in any person other than a corporation which, in either case, are not Common Shares;

*"Prudential and Credit Support Obligations"* means all contingent obligations of the Corporation or its Subsidiaries relating to letters of credit, guarantees and other financial instruments incurred, provided or assumed by the Corporation or its Subsidiaries in the ordinary course of business to satisfy or otherwise comply with prescribed prudential and credit support arrangements required by the BCUC or any governmental authority;

*"Purchase Money Obligation"* means any unpaid part of or Indebtedness issued, incurred or assumed to finance all or part of the cost of acquiring any real or tangible personal property, including installation costs and expenditures made for any repairs, alterations, construction, development or improvements performed thereon or thereto; provided that the Indebtedness is issued, incurred or assumed within 12 months following the acquisition of such property or the completion of the installation, repairs, alterations, construction, development or improvements thereto or thereon, and includes any extension, renewal or refunding of any such Indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

*"Purchase Money Security Interest"* means any Lien on real or tangible personal property which is created, issued or assumed by the Corporation or any Subsidiary to secure the Purchase Money Obligation in respect of such property and includes any extension, renewal or refunding thereof so long as the principal amount outstanding on the date of such extension, renewal or refunding is not increased; provided that such Lien is limited to the property acquired in connection with the issuance, incurring or assumption of such Purchase Money Obligation;

*"Securities"* means any stock, shares, units, instalment receipts, voting trust certificates, bonds, debentures, notes, other evidences of indebtedness, or other documents or instruments commonly known as securities or any certificates of interest, shares or participations in, temporary or interim certificates for, receipts for, guarantees of, or warrants, options or rights to subscribe for, purchase or acquire, any of the foregoing;

*"Shareholders' Equity"* means (a) in respect of a corporation, the aggregate amount of shareholders' equity (including Common Share capital, preferred share capital if issued directly by the corporation, contributed surplus and retained earnings) as shown on the most recent quarterly or annual balance sheet of such corporation calculated in accordance with GAAP and (b) in respect of any entity other than a corporation (including a partnership), the aggregate amount of equity (including partnership equity) as shown on the most recent quarterly or annual balance sheet of such entity calculated in accordance with GAAP;

*"Subordinated Debt"* means Indebtedness which would be Preferred Securities within the meaning of clause (a) of the definition of Preferred Securities but without regard to their term to maturity and Indebtedness which, pursuant to the terms of a subordination agreement entered into with the Trustee (a) is subordinated in all rights to senior Indebtedness, (b) has no contractual rights of acceleration until at least 180 days following a Default or an Event of Default while any senior Indebtedness remains outstanding, (c) does not permit any prepayments or any payments to be made in respect thereof at any time when monies are due and payable with respect to senior Indebtedness and (d) in the event of any insolvency, bankruptcy, receivership, liquidation, arrangement, reorganization or other similar proceeding, is paid only after all senior Indebtedness has been paid in full;

*"Subsidiary"* means:

(a) any corporation of which Securities, having by the terms thereof ordinary voting power to elect a majority of the board of directors of such corporation (irrespective of whether at the time shares of any other class or classes of such corporation might have voting power by reason of the happening of any contingency, unless the contingency has occurred and then only for as long as it continues), are at the time directly, indirectly or beneficially owned or controlled by the Corporation or one or more of its Subsidiaries, or the Corporation and one or more of its Subsidiaries;

(b) any partnership of which the Corporation, or one or more of its Subsidiaries, or the Corporation and one or more of its Subsidiaries: (i) directly, indirectly or beneficially owns or controls more than 50% of the income, capital, beneficial or ownership interest (however designated) thereof; and (ii) is a general partner, in the case of a limited partnership, or is a partner that has the authority to bind the partnership in all other cases; or

(c) any other person of which at least a majority of the income, capital, beneficial or ownership interest (however designated) is at the time directly, indirectly or beneficially owned or controlled by the Corporation, or one or more of its Subsidiaries or the Corporation and one or more of its Subsidiaries;

*"Taxes"* means all taxes, charges, fees, levies, imposts and other assessments, including all income, sales, use, goods and services, value added, capital, capital gains, alternative, net worth, transfer, profits, withholding, payroll, employer health, excise, real property and personal property taxes, and any other taxes, customs duties, fees, assessments or similar charges in the nature of a tax, including Canada Pension Plan and Québec Pension Plan contributions, employment insurance payments and workers' workplace, health, safety and compensation premiums, together with any instalments with respect thereto, and any interest, fines and penalties with respect thereto, imposed by any governmental authority (including federal, provincial, municipal and foreign governmental authorities), and whether disputed or not;

*"Total Consolidated Capitalization"* means, as at any date, with respect to the Corporation, without duplication, the sum of (a) Consolidated Net Worth, (b) the principal amount of all Preferred Securities (for certainty, without duplication of Preferred Securities included in Consolidated Net Worth), (c) the principal amount of all Consolidated Funded Obligations and (d) the principal amount of all Subordinated Debt, as determined on a consolidated basis in accordance with GAAP;

*"Trust Deeds"* means (a) the deed of trust and mortgage made as of March 15, 1983 between the Corporation and The Canada Trust Company (since replaced by Computershare Trust Company of Canada); and (b) the deed of trust made as of February 1, 1996 between the Corporation and Montreal Trust Company of Canada (since replaced by Computershare Trust Company of Canada), each as amended by supplemental indentures to the date hereof;

*"Trust Deeds Indebtedness"* means the indebtedness of $45.25 million principal amount owing by the Corporation in respect of the Series E, F and G Debentures issued under the Trust Deeds;

*"Trust Deeds Liens"* means Liens against any property or assets of the Corporation providing security for obligations of the Corporation under the Trust Deeds Indebtedness;

*"Walden Indebtedness"* means the indebtedness of no more than $7.048 million principal amount owing by the Walden Power Partnership under a loan agreement dated October 15, 1993 and made among the Walden Power Partnership (in which the Corporation has a general partnership interest), as borrower, ESI Power-Walden Corporation Ltd., West Kootenay Power Ltd. (formerly called 413569 British Columbia Ltd.) and The Mutual Life Assurance Company of Canada, as lender; and

*"Walden Liens"* means the pledge by the Corporation of all of its partnership interests and units in Walden Power Partnership pursuant to a pledge and security agreement made September 30, 1994 between the Corporation and The Mutual Life Assurance Company of Canada and the mortgage of certain real property as security for the Walden Indebtedness.

## RATINGS

The Debentures have been rated BBB (high), stable trend, by DBRS Limited ("DBRS") and Baa2, stable outlook, by Moody's Investors Service ("Moody's").

Ratings are not recommendations to purchase, hold or sell securities, because ratings do not comment as to market price or suitability for a particular investor. The Corporation understands that ratings are based on, among other things, information furnished to the rating agencies by the Corporation and information obtained by the rating agencies from public sources. Ratings may be changed, suspended or withdrawn as a result of changes in, or unavailability of, that information.

DBRS's long term debt ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within that category. DBRS states that its long term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner, with respect to both interest and principal commitments. DBRS ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment process. Every DBRS rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. A rating of BBB by DBRS is in the middle of three subcategories and within the fourth highest of nine major categories. According to DBRS, long term debt rated BBB is of adequate credit quality; protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

Moody's long term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's long term debt ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. A rating of Baa by Moody's is the fourth highest of nine major categories. According to Moody's, long term obligations rated Baa are subject to moderate credit risk; they are considered to be medium-grade and as such may possess certain speculative characteristics.

## EARNINGS COVERAGE RATIOS

The following earnings coverage ratios have been calculated for the twelve month periods ended December 31, 2006 and March 31, 2007 and set out the Corporation's interest requirements after giving effect to the issue of the Debentures and the use of the proceeds therefrom, net of the issue costs to the Corporation.

| | Twelve Months Ended March 31, 2007 | Twelve Months Ended December 31, 2006 |
|---|---|---|
| | (dollars in thousands) | |
| **Interest coverage**(1) | | |
| Earnings before interest and income tax | $ 58,454 | $ 59,590 |
| Interest requirements | $ 32,313 | $ 32,405 |
| Interest coverage | 1.81 times | 1.84 times |

Note:

(1) The interest coverage calculations have been made to give effect to the issue of the Debentures as if it occurred at the beginning of the relevant twelve month period.

## USE OF PROCEEDS

The net proceeds to the Corporation from the Offering are estimated to be $103,511,150 after deducting expenses of the Offering, which are estimated to be $400,000, and the fee payable to the Underwriters. Approximately $82.0 million of the net proceeds of the Offering will be used to repay certain existing indebtedness under the Corporation's credit facilities, $31.0 million of which was incurred to repay affiliate demand notes due to Fortis Inc. and the balance of which was incurred primarily to fund capital expenditures. The balance of the proceeds remaining thereafter is planned to be used for general corporate purposes, including future capital expenditures. For the last six months of 2007, the Corporation has forecast capital expenditures in excess of the balance of the proceeds to continue replacement and expansion of infrastructure. Additional financing required to fund these capital expenditures is planned to come from working capital and draws on the Credit Facilities. See "Plan of Distribution".

## PLAN OF DISTRIBUTION

Under an underwriting agreement dated June 22, 2007 (the "Underwriting Agreement") between the Corporation and the Underwriters, the Corporation has agreed to sell, and the Underwriters have agreed to purchase as principals, on the Closing Date, subject to the conditions contained in the Underwriting Agreement, all but not less than all of $105,000,000 principal amount of the Debentures at an aggregate price of $104,856,150 ($998.63 per $1,000 principal amount of Debentures), payable in cash to the Corporation against delivery of the Debentures. The Underwriters will be paid an aggregate fee of $945,000 ($9.00 per $1,000 principal amount of Debentures) on account of services rendered to the Corporation in connection with the Offering. The obligations of the Underwriters under the Underwriting Agreement are several as to their respective underwriting commitments and may be terminated upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all the Debentures if any of the Debentures are purchased.

In connection with the Offering, the Underwriters may, subject to applicable laws, effect transactions that are intended to stabilize or maintain the market price of the Debentures at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this short form prospectus. See "Risk Factors". The Corporation does not intend to list the Debentures on any securities exchange or to arrange for any quotation system to quote them.

The Debentures have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "1933 Act"), or any state securities laws and, subject to certain exceptions, may not be offered or delivered, directly or indirectly, or sold in the United States except in certain transactions exempt from the registration requirements of the 1933 Act and in compliance with any applicable state securities laws. The Underwriters have agreed that they will not offer or sell the Debentures within the United States, its territories, its possessions and other areas subject to its jurisdiction or to, or for the account or benefit of, a "U.S. Person" (as defined in Regulation S under the 1933 Act), except in accordance with exemptions from the registration requirements of the 1933 Act provided by Rule 144A thereunder and in compliance with applicable state securities laws. Debentures issued pursuant to an exemption from the registration requirement of the 1933 Act will be issued in "book-entry form" and will be represented by a Global Debenture. Such Debentures will be subject to certain restrictions on transfer set forth therein and in the Indenture and will bear a legend regarding such restrictions as set forth in the Indenture. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Debentures in the United States. In addition, until 40 days after the commencement of the Offering, an offer or sale of Debentures within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act if such offer is made otherwise than in reliance on Rule 144A.

The Corporation has agreed to indemnify the Underwriters against certain liabilities, including liabilities under applicable securities laws, or to contribute to payments they may be required to make in respect thereof.

Each of the Underwriters is an affiliate of a Canadian chartered bank (the "Bank Affiliates") that is currently a lender to the Corporation under unsecured operating, term or overdraft credit facilities (collectively, the "Credit Facilities"). As at March 31, 2007, an aggregate of $7.6 million was owed by the Corporation to the Bank Affiliates under the Credit Facilities. The Corporation estimates that approximately $48.8 million of the net proceeds to the Corporation from the Offering will be used to repay indebtedness owed to the Bank Affiliates under the Credit Facilities. Consequently, the Corporation may be considered a "connected issuer" of each of the Underwriters within the meaning of applicable securities legislation. The Corporation is in compliance with the terms of the agreements governing the Credit Facilities.

The decision to distribute the Debentures and the determination of the terms of the Offering were made through negotiation between the Corporation and the Underwriters. The Bank Affiliates did not have any involvement in that decision or determination. None of the Underwriters will receive any direct benefit from the Offering other than its respective share of the Underwriters' fee.

## RISK FACTORS

An investment in the Debentures involves certain risks. Before investing, prospective purchasers of Debentures should carefully consider, in light of their own financial circumstances, the factors set out below, as well as the other information contained or incorporated by reference in this short form prospectus.

### Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the normal uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on rate base assets. These uncertainties also include the possibility that the Corporation would be ordered to increase its debt to total capital ratio. Such a change may, in turn, lead to reduced interest coverage ratios and an increase in risk to holders of Debentures. The ability of the Corporation to recover the actual costs of providing services and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. The cost of upgrades to existing facilities and the addition of new facilities require the approval of the BCUC for inclusion in the rate base. There is no assurance that capital projects perceived as required by the management of the Corporation will be approved or that conditions to such approval will not be imposed. Capital cost overruns might not be recoverable in rates.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures in British Columbia. Failing a negotiated settlement, rate applications may be pursued through public hearing processes. The BCUC has issued an order setting rates for 2007. BCUC approval of rates for 2008, and for future years, will be required. There can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed upgrades or expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact the Corporation's results of operations or financial position.

### Electricity Demand

A general and extended decline in British Columbia's economy, or in the Corporation's service area in particular, would be expected to have the effect of reducing demand for electric energy over time. Electricity demand by some of the Corporation's industrial customers could exhibit variations in demand or load in such circumstances. In addition, the increased development of alternative sources of energy in British Columbia could have the effect of creating competition, and reducing demand, for electrical energy from FortisBC. A decrease in demand could potentially reduce the revenues of the Corporation. Also, an economic downturn could impair the ability of some end-use customers to pay for electricity received. Any such prolonged economic downturn in British Columbia or in the Corporation's service area could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

### Weather and Natural Disasters

The facilities of the Corporation are exposed to the effects of severe weather conditions and other natural events. Although the Corporation's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In addition, many of these facilities are located in remote areas which makes it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Corporation operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events. The Corporation has limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC will approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute electricity to them in accordance with the Corporation's contractual obligations. Thus, any major damage to the Corporation's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Corporation.

### Equipment Breakdown, Operating and Maintenance Risk

FortisBC's assets require ongoing maintenance, improvement and replacement. Accordingly, in order to ensure the continued performance of the Corporation's physical assets, the Corporation determines expenditures that must be made to maintain and replace assets. FortisBC could experience service disruptions and increased costs if it is unable to maintain its asset base. The inability to recover, through approved rates, capital expenditures that the Corporation believes are necessary to maintain, improve and replace its assets, the failure by the Corporation to properly implement or complete approved capital expenditure programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Corporation.

The Corporation continually develops capital expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation of its business. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which are uncertain. If actual costs exceed forecasted capital expenditures, it is uncertain as to whether any cost overruns will be approved by the BCUC and recovered through rates. The inability to recover cost overruns could have a material adverse effect on the financial condition and results of operations of the Corporation.

### Interest Rates

The Corporation is exposed to interest rate risks associated with floating rate debt. Regulated utilities such as the Corporation are also exposed to changes in the general level of interest rates. As interest rates decrease, so does the allowed return on equity. A significant decline in interest rates could adversely affect the Corporation's ability to earn a reasonable return on equity, which, in turn, could have a material adverse effect on the financial condition and results of operations of the Corporation.

### Capital Resources

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from operations, after payment of expected expenses (including interest payments on any outstanding debt), will not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. The

Corporation's ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in British Columbia, the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets and the ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

**Credit Risk and Prior Ranking Indebtedness**

The likelihood that purchasers of the Debentures will receive payments owing to them under the terms of the Debentures will depend on the financial health of the Corporation and its creditworthiness. In addition, the Debentures are unsecured obligations of the Corporation. Therefore, if the Corporation becomes bankrupt, liquidates its assets, reorganizes or enters into certain other transactions, the Corporation's assets will be available to pay its obligations with respect to the Debentures only after it has paid all of its secured indebtedness in full. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding.

The Corporation has $45.25 million outstanding aggregate principal amount of debentures which are secured by a first fixed and floating charge against all of the assets of the Corporation, and which accordingly rank in priority to the Debentures. See "Details of the Offering — Ranking".

**Labour Relations**

Approximately 80% of the employees of the Corporation are members of labour unions that have entered into collective bargaining agreements with the Corporation. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Corporation. The Corporation considers its relationships with its labour unions to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have an adverse effect on the financial condition and results of operations of the Corporation.

**Environmental Matters**

The Corporation is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Corporation. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events, including severe weather and other natural disasters, human error or misconduct or equipment failure. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material adverse effect on the business, results of operations, financial condition and prospects of the Corporation.

The Corporation is exposed to environmental risks that owners and operators of properties in British Columbia generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental, health and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. The Corporation has not been notified of any such regulatory action in regard to the operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Corporation.

Although most of the Corporation's generating and transmission facilities have been in place for many years with no apparent adverse environmental impact, environmental assessments and approvals may be required in the ordinary course of business for existing and future facilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, on which the Corporation's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at the Corporation's plants or at plants operated by parties contracted to supply energy to the Corporation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and conducting environmental impact assessments and remediation. It is possible that other developments may lead to increasingly strict environmental and safety laws, regulations and enforcement policies and claims for damages to property or persons resulting from the Corporation's operations, any one of which could result in substantial costs or liabilities to the Corporation. Any regulatory changes that impose additional environmental restrictions or requirements on the Corporation or its customers could adversely affect the Corporation through increased operating and capital costs.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electro-magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electro-magnetic fields present a health hazard, litigation could result and the Corporation could be required to take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures could be material.

Spills and leaks can occur in the operation of electricity transmission facilities, including, primarily, accumulations of oil containing hydrocarbons and PCB contaminants in soil and gravel at substation sites. The Corporation remediates such sites in accordance with environmental regulations and standards and sound industry practice. There can be no assurance that the Corporation will not be obligated to incur further expenses in connection with changes in environmental regulations and standards or as a result of historical contamination.

Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line or lightning strikes to wooden poles. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third party facilities located near the land on which the transmission facilities are situate. The Corporation may be liable for fire-fighting costs and third party claims in connection with fires on these or other lands on which its transmission facilities are located, and such claims, if successful, could have a material adverse effect on the business, results of operations and prospects of the Corporation.

While the Corporation maintains insurance, the insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the possible types of liabilities that may be incurred by the Corporation will be covered by its insurance. See "— Underinsured and Uninsured Losses" below.

Electricity transmission and distribution has inherent potential risks and there can be no assurance that substantial costs and liabilities will not be incurred. Potential environmental damage and costs could materialize due to some type of severe weather event or major equipment failure and there can be no assurance that such costs would be recoverable. Unrecovered costs could have a material adverse effect on the Corporation's business, results of operations and prospects.

**First Nations Lands**

The Corporation provides service to customers on First Nations reserves in British Columbia and maintains generation, transmission and distribution facilities on lands that are subject to land claims by various First Nations bands. A treaty negotiation process involving various First Nations bands and the Government of British Columbia is underway in British Columbia but the basis upon which settlements might be reached in the Corporation's service area is not clear. Furthermore, not all First Nations bands are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Corporation. However, there can be no certainty that the settlement process will not adversely affect the Corporation's business.

**Underinsured and Uninsured Losses**

The Corporation maintains insurance coverage at all times with respect to potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available on terms as favourable as the Corporation's existing arrangements. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's business, results of operations, financial position and prospects.

In the event of an uninsured loss or liability, the Corporation would apply to the BCUC to recover the loss (or liability) through an increased tariff. However, there can be no assurance that the BCUC would approve any such application, in whole or in part. Any major damage to the Corporation's facilities could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's business, results of operations, financial position and prospects.

**Power Supply Contracts**

The Corporation's indirect customers are directly served by FortisBC's wholesale customers, who themselves are municipal utilities. Those utilities may be able to obtain alternate sources of energy supply. Also, the Corporation enters into agreements with third parties for the supply of electricity which have various expiry dates. FortisBC may not be able to secure an extension of any such agreement or, if such an agreement is not extended, an alternate supply of similarly-priced electricity. The Corporation is also subject to the risk that the counterparty for such an agreement may default on its obligation to supply electricity. Any such event could adversely affect the business, results of operations, financial position and prospects of the Corporation.

**Weather Related Demand Loss**

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. Cool summers may reduce air-conditioning demand, while warm winters may reduce electric heating load. Such fluctuations in demand could adversely affect the business, results of operations, financial condition and prospects of the Corporation.

**Permits**

The acquisition, ownership and operation of electricity businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies. The Corporation may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the sale of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

The Corporation's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the amended and restated Canal Plant Agreement made as of July 1, 2005 among British Columbia Hydro and Power Authority ("BC Hydro"), Teck Cominco Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation, Waneta Expansion Power Corporation and the Corporation (the "Canal Plant Agreement") depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). The Canal Plant Agreement provides for the coordination and integration of the electrical generation and transmission systems of each of the Corporation, BC Hydro, Teck Cominco Metals Ltd. and Brilliant Power Corporation. In addition, water flows in the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States. Government authorities in Canada and the United States have the power under the treaty to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power.

**Climate Change**

The Corporation's entitlement to capacity and energy under the Canal Plant Agreement may be reduced if climate change in the future leads to a significant and sustained loss of precipitation over the entire headwaters of the Kootenay River system. To have an effect on the entitlements of capacity and energy, such change would likely have to persist for more than a decade.

**Credit Ratings**

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Debentures are not a recommendation to purchase, hold or sell the Debentures, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time or that these ratings will not be revised or withdrawn entirely in the future by the relevant rating agency. Real or anticipated changes in credit ratings on the Debentures may affect the market value of the Debentures. In addition, real or anticipated changes in credit ratings can affect the cost of or terms on which FortisBC can issue debentures or incur other debt.

### Market Value Fluctuation

Prevailing interest rates will affect the market value of the Debentures, as they carry a fixed interest rate. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline.

### Lack of Public Market for Debentures

The Offering is a new issue of debt securities for which there is no existing trading market. The Corporation does not intend to list the Debentures on any securities exchange or to arrange for any quotation system to quote them, and consequently the Corporation will not be subject to regulation by any securities exchange or quotation system. There can be no assurance as to the liquidity of any trading market for the Debentures or that a trading market for any of the Debentures will develop. Even if a trading market develops in the Debentures, those Debentures could trade at prices that may be higher or lower than their initial offering prices and there may be limited transparency of trading prices. The market price for the Debentures may be affected by prevailing interest rates, FortisBC's results of operations and financial position, the ratings assigned to the Debentures or other indebtedness of FortisBC, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Corporation.

## CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Farris, Vaughan, Wills & Murphy LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the following is a summary of the principal Canadian federal income tax considerations generally applicable to a holder of Debentures who acquires the Debentures pursuant to this short form prospectus and who, at all relevant times, for purposes of the *Income Tax Act* (Canada) (the "Tax Act"), is or is deemed to be resident in Canada, holds the Debentures as capital property, deals at arm's length with the Corporation and is not exempt from tax under Part I of the Tax Act. Generally, the Debentures will be considered to be capital property to a holder provided that the holder does not hold the Debentures in the course of carrying on a business and has not acquired them in a transaction or transactions considered to be an adventure in the nature of trade. Purchasers whose Debentures do not otherwise qualify as capital property may make, in certain circumstances, the irrevocable election under subsection 39(4) of the Tax Act to have such Debentures and every "Canadian security" (as defined in the Tax Act) owned by such holder in the taxation year of the election, and in all subsequent years, deemed to be capital property.

This summary is based on the current provisions of the Tax Act and the regulations thereunder, all specific proposals to amend the Tax Act and the regulations publicly announced by, or on behalf of, the Minister of Finance (Canada) prior to the date hereof, and counsel's understanding of the current published administrative practices of the Canada Revenue Agency . This summary does not otherwise take into account or anticipate any change in law, whether by legislative, governmental or judicial decision or action, nor does it take into account or consider any provincial, territorial or foreign income tax legislation or considerations which may differ significantly from those discussed herein.

This summary does not take into account the "mark-to-market rules" applicable to securities held by certain financial institutions, registered securities dealers and corporations controlled by one or more of the foregoing and, accordingly, holders that are "financial institutions" (as defined in the Tax Act for purposes of these rules) should consult their own tax advisors.

**This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder of Debentures, and no representations with respect to the income tax consequences to any particular holder of Debentures are made. Accordingly, prospective purchasers should consult their own tax advisors with respect to their particular circumstances.**

### Interest on the Debentures

A holder that is a corporation, partnership, unit trust or trust of which a corporation or partnership is a beneficiary will be required to include in its income for a taxation year any interest on a Debenture that accrues or is deemed to accrue to the holder to the end of the taxation year or becomes receivable or is received by it before the end of that taxation year, except to the extent that such amount was included in its income for a preceding taxation year.

Any other holder, including an individual, will be required to include in income for a taxation year all interest on a Debenture received or receivable by such holder in that taxation year (depending upon the method regularly followed by the holder in computing income), except to the extent that such amount was included in the holder's income for a preceding taxation year. If such holder has not otherwise included in income interest on the Debenture at periodic intervals of not more than one year, the holder will also be required to include in the holder's income, for any taxation year that includes an "anniversary day" (as defined in the Tax Act) of the Debenture, any interest which accrued to the holder to the end of such day, to the extent such interest was not otherwise included in computing the holder's income for that year or a preceding year.

A holder of a Debenture that is a "Canadian-controlled private corporation" (as defined in the Tax Act) may be liable for a refundable tax of 6⅔% on certain investment income, which will include interest on the Debentures that is included in the holder's income.

In the event the Debentures are issued at a discount from their face value, a holder may be required to include an additional amount in computing income, either in accordance with deemed interest accrual rules contained in the Tax Act and the regulations under the Tax Act or in the taxation year in which the discount is received or receivable by the Holder. Holders should consult their own tax advisors in these circumstances, as the tax treatment of the discount may vary depending upon the facts and circumstances giving rise to it.

**Disposition of Debentures**

On a disposition or deemed disposition of a Debenture, including a redemption or purchase by the Corporation, a holder will generally be required to include in income for the taxation year in which the disposition occurs the amount of interest accrued or deemed to have accrued on such Debenture up to the date of the disposition and that is not payable until after that date, to the extent that such amounts have not otherwise been included in the holder's income for that year or a preceding taxation year. In addition, any premium paid by the Corporation to a holder, as a result of the Corporation's exercise of its right to redeem a Debenture before the maturity thereof, will be deemed to be interest received by the holder at the time of the redemption to the extent that it can reasonably be considered to relate to, and does not exceed the value at the time of the redemption of, the interest that would have been paid or payable by the Corporation on the Debenture for a taxation year ending after the redemption.

In general, a disposition or deemed disposition of a Debenture will give rise to a capital gain (or capital loss) to the extent that the proceeds of disposition, net of any amount included in the holder's income as interest and any reasonable costs of disposition, exceed (or are less than) the holder's adjusted cost base of such Debenture immediately before the disposition.

One-half of any capital gain (a "taxable capital gain") realized by a holder in a taxation year must be included in computing the holder's income in that year. One-half of any capital loss (an "allowable capital loss") realized by a holder in a taxation year will be deducted from the holder's taxable capital gains in that year. Allowable capital losses in excess of taxable capital gains generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent year against net taxable capital gains realized in such years to the extent and under the circumstances described in the Tax Act.

Capital gains realized by an individual may give rise to a liability for alternative minimum tax under the Tax Act. A holder that is a "Canadian-controlled private corporation" (as defined in the Tax Act) may be subject to an additional refundable tax of 6⅔% on certain investment income, including amounts in respect of taxable capital gains.

## ELIGIBILITY FOR INVESTMENT

In the opinion of Farris, Vaughan, Wills & Murphy LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the Debentures would, if issued on the date hereof, be qualified investments under the Tax Act for trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans or deferred profit sharing plans (other than a trust governed by a deferred profit sharing plan in respect of which any employer is the Corporation or is a person that does not deal at arm's length with the Corporation within the meaning of the Tax Act).

## LEGAL MATTERS

Certain legal matters relating to the Offering will be passed upon on behalf of the Corporation by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Underwriters by Stikeman Elliott LLP. At the date hereof, partners and associates of each of Farris, Vaughan, Wills & Murphy LLP and Stikeman Elliott LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any affiliate of the Corporation.

## AUDITORS AND TRUSTEE

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 700 West Georgia Street, P.O. Box 10101, Vancouver, British Columbia, V7Y 1C7.

Computershare Trust Company of Canada, at its office located at 510 Burrard Street, Vancouver, British Columbia V6C 3B9, is the Trustee under the Indenture. Registers for the registration and transfer of the Debentures will be kept at the offices of the Trustee in Vancouver, British Columbia. The Trustee is also the paying agent for the Debentures.

## PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a short form prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the short form prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

**AUDITORS' CONSENT**

We have read the short form prospectus of FortisBC Inc. (the "Corporation") dated June 22, 2007 relating to the issue and sale of $105,000,000 principal amount of 5.90% senior unsecured debentures due July 4, 2047 of the Corporation. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form prospectus of our report dated January 26, 2007 to the shareholder of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2006 and 2005, and the consolidated statements of earnings, retained earnings and cash flows for the years ended December 31, 2006 and 2005.

(Signed) Ernst & Young LLP
Chartered Accountants

Vancouver, Canada
June 22, 2007

## GLOSSARY OF TERMS

*In this short form prospectus, unless the context otherwise requires, the following terms have the meanings set forth below. Certain terms used in the Indenture have the meanings set forth in "Details of the Offering — Definitions".*

**"Amended and Restated Credit Facility"** means the amended and restated credit facility made as of May 12, 2005 and as amended on May 5, 2006 and May 8, 2007, between the Corporation and a syndicate of Canadian chartered banks.

**"Bank Affiliates"** means Canadian chartered banks that are lenders to the Corporation and are affiliated with Underwriters.

**"BC Hydro"** means British Columbia Hydro and Power Authority.

**"BCUC"** means the British Columbia Utilities Commission.

**"Canal Plant Agreement"** means the amended and restated Canal Plant Agreement made as of July 1, 2005 among BC Hydro, Teck Cominco Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation, Waneta Expansion Power Corporation and the Corporation.

**"CDS"** means CDS Clearing and Depository Services Inc.

**"Closing Date"** means July 4, 2007 or such other date as the Corporation and the Underwriters agree upon.

**"Corporation"** means FortisBC Inc.

**"Credit Facilities"** means Facility A, Facility B or the overdraft credit facility made available to the Corporation.

**"DBRS"** means DBRS Limited.

**"Debentures"** means the 5.90% Senior Unsecured Debentures due July 4, 2047 offered by this short form prospectus, and **"debentures"** means debentures of any series issued and outstanding under the Indenture from time to time.

**"Depository"** means CDS or such other nationally recognized clearing agency as is designated by the Corporation to act a depository in respect of one or more series of book-entry only debentures.

**"Facility A"** means the $50.0 million, three year revolving facility maturing on May 12, 2010 under the Amended and Restated Credit Facility.

**"Facility B"** means the $100.0 million, 364-day revolving facility maturing May 8, 2008 under the Amended and Restated Credit Facility.

**"First Supplemental Indenture"** means the first supplemental indenture to the Principal Indenture dated as of November 10, 2005.

**"FortisBC"** means FortisBC Inc.

**"Global Debenture"** means a book-entry only global certificate evidencing the Debentures which will be delivered to, and registered in the name of, CDS or its nominee.

**"Indenture"** means the Principal Indenture, as supplemented and amended by the First Supplemental Indenture, the Second Supplemental Indenture and as from time to time supplemented and amended by further supplemental indentures.

**"Moody's"** means Moody's Investors Service.

**"Offering"** means the distribution of the Debentures pursuant to this short form prospectus.

**"Participants"** means participants, including securities brokers and underwriters, banks and trust companies, in the depository service of CDS.

**"Principal Indenture"** means the trust indenture dated as of November 30, 2004 between the Corporation and the Trustee.

**"Second Supplemental Indenture"** means an indenture supplementing the Principal Indenture, as supplemented and amended by the First Supplemental Indenture, and dated the Closing Date, pursuant to which the Debentures will be issued.

**"Tax Act"** means the *Income Tax Act* (Canada).

**"Trustee"** means Computershare Trust Company of Canada.

**"Underwriters"** means, collectively, Scotia Capital Inc., CIBC World Markets Inc. and National Bank Financial Inc.

**"Underwriting Agreement"** means the underwriting agreement dated June 22, 2007 between the Corporation and the Underwriters relating to the sale of the Debentures offered by this short form prospectus.

*All dollar amounts in this short form prospectus are expressed in Canadian dollars.*

## CERTIFICATE OF FORTISBC INC.

Dated: June 22, 2007

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain and disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of all of the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, together with the documents incorporated herein by reference and as supplemented by the permanent information record, contains no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

(Signed) JOHN C. WALKER
President and Chief Executive Officer

(Signed) MICHELE I. LEENERS
Vice President, Finance and Chief Financial Officer

On behalf of the Board of Directors

(Signed) H. STANLEY MARSHALL
Director

(Signed) BARRY V. PERRY
Director

## CERTIFICATE OF THE UNDERWRITERS

Dated: June 22, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of all of the provinces of Canada. For the purpose of the Province of Québec, to our knowledge, this simplified prospectus, together with documents incorporated herein by reference and as supplemented by the permanent information record, contains no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

SCOTIA CAPITAL INC.

By: (Signed) D. GREGORY LAWRENCE

CIBC WORLD MARKETS INC.

By: (Signed) DARRELL BURT

NATIONAL BANK FINANCIAL INC.

By: (Signed) PETER RUSHELEAU

FORTISBC

BOWNE
PRINTED IN CANADA
O36832

*This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.*



***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the secretary of the issuer at Suite 100, 1975 Springfield Road, Kelowna, British Columbia V1Y 7V7 (telephone (250) 469-8014), and are also available electronically at www.sedar.com.*

***New Issue*** **May 22, 2009**

**SHORT FORM BASE SHELF PROSPECTUS**

FORTISBC

# FortisBC Inc.
# $300,000,000
# Medium Term Note Debentures
# (unsecured)

FortisBC Inc. ("FortisBC" or the "Corporation") may offer to the public in each of the provinces of Canada from time to time Medium Term Note Debentures (the "MTN Debentures") due not less than one year from the date of issue at prices and on terms determined at the time of issue, in an aggregate principal amount not to exceed $300,000,000 (or the equivalent thereof in foreign currencies based on the applicable exchange rate at the time of offering), during the twenty-five month period that this short form prospectus, including any amendments hereto, remains valid.

The MTN Debentures will be direct, senior, unsecured and unsubordinated obligations of the Corporation ranking equally, except as to sinking fund provisions, with all other present and future unsecured and unsubordinated obligations of the Corporation. The specific terms of any offering of MTN Debentures, including the aggregate principal amount of MTN Debentures offered, the currency, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), issue and delivery date, interest payment date(s), maturity date, any redemption and sinking fund provisions, the price to the public, the names of any Dealers (as defined below), any Dealers' commission and the actual proceeds to the Corporation will be set forth in a pricing supplement or other prospectus supplement which will accompany this short form prospectus and any amendments hereto. The Corporation reserves the right to set forth in a pricing supplement or other prospectus supplement specific terms of MTN Debentures which are not within the options and parameters set forth in this short form prospectus.

## Rates on Application

The MTN Debentures may be offered severally by any one or more of CIBC World Markets Inc., HSBC Securities (Canada) Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and Scotia Capital Inc. pursuant to the dealer agreement dated May 22, 2009 (the "Dealer Agreement") referred to under "Plan of Distribution" or other investment dealers selected from time to time by the Corporation (collectively, the "Dealers" and each a "Dealer"). The MTN Debentures may be sold from time to time by the Dealers acting as agents of the Corporation. The MTN Debentures may also be purchased from time to time by any of the Dealers, as underwriter or dealer purchasing as principal, at such prices as may be agreed upon between the Corporation and such Dealer, for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. The Dealers may, on behalf of the Corporation, solicit offers to purchase the MTN Debentures at such prices as may be established from time to time by consultation between the Corporation and the Dealers and with such commissions as set forth in the Dealer Agreement or as are agreed to between the Corporation and the Dealers. Each Dealer's compensation will be increased or decreased by the amount by which the aggregate price paid for MTN Debentures by purchasers exceeds or is less than the gross proceeds paid by the Dealer, when purchasing as principal, to the Corporation. The MTN Debentures may also be offered directly to the public by the Corporation pursuant to applicable statutory or discretionary exemptions at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commission will be paid to the Dealers.

In connection with any offering of MTN Debentures, the Dealers may, subject to applicable laws, over-allot or effect transactions which stabilize or maintain the market price of the MTN Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

**There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".**

**Each of CIBC World Markets Inc., HSBC Securities (Canada) Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and Scotia Capital Inc. is an affiliate of a Canadian chartered bank which has extended credit facilities to the Corporation upon which the Corporation may draw from time to time. Consequently, FortisBC may be considered to be a "connected issuer" of each of these Dealers for the purposes of Canadian securities legislation. All or a portion of the net proceeds of the sale of particular series or issue of MTN Debentures in which such Dealers are acting as principals or agents may be used to repay indebtedness under such credit facilities. See "Relationship Between FortisBC and Certain Dealers" and "Use of Proceeds".**

The offering is subject to approval of certain legal matters on behalf of the Corporation by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Dealers by Lawson Lundell LLP.

FortisBC's head office and registered office is located at Suite 100, 1975 Springfield Road, Kelowna, British Columbia V1Y 7V7.

**TABLE OF CONTENTS**


FORWARD-LOOKING INFORMATION ............... 3
DOCUMENTS INCORPORATED BY REFERENCE ............... 4
THE CORPORATION ............... 5
DETAILS OF THE OFFERING ............... 5
RATINGS ............... 18
EARNINGS COVERAGE RATIOS ............... 18
USE OF PROCEEDS ............... 19
PLAN OF DISTRIBUTION ............... 19
ELIGIBILITY FOR INVESTMENT ............... 20
RISK FACTORS ............... 20
RELATIONSHIP BETWEEN FORTISBC AND CERTAIN DEALERS ............... 21
LEGAL MATTERS ............... 22
AUDITORS AND TRUSTEE ............... 22
PURCHASERS' STATUTORY RIGHTS ............... 22
AUDITORS' CONSENT ............... A-1
CERTIFICATE OF FORTISBC INC. ............... C-1
CERTIFICATE OF THE DEALERS ............... C-2


## FORWARD-LOOKING INFORMATION

Certain statements contained in this short form prospectus, including the documents incorporated by reference herein, contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include, but are not limited to: receipt of applicable regulatory approvals and requested rate orders; continued electricity demand; absence of adverse weather conditions, natural disasters and equipment breakdown; no significant decline in interest rates; the ability to arrange sufficient and cost effective financing; the ability to maintain and renew collective bargaining agreements on acceptable terms; absence of environmental damage; the First Nations' settlement process does not adversely affect the Corporation; the adequacy of the Corporation's existing insurance arrangements; that counterparties do not default on power supply contracts; no weather related demand loss; ability to maintain and obtain applicable permits; climate change does not reduce water flows; and, no material adverse increase in employee future benefit costs.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; electricity demand risk; weather and natural disasters, equipment breakdown, operating and maintenance risk; interest rates risk; capital resources risk; labour relations risk; environmental matters risk; First Nations' land matters risk; underinsured and uninsured losses; power supply contract risk; weather related demand loss; permits risk; climate change risk; employee future benefits risk; credit risk and risks relating to prior ranking indebtedness; credit rating risk; market value fluctuation; lack of public market for MTN Debentures; and other risks described in this short form prospectus, including the documents incorporated by reference herein. For additional information with respect to these risk factors, reference should be made to "Risk Factors".

All forward-looking information in this short form prospectus, including the documents incorporated by reference herein, is qualified in its entirety by this cautionary statement and, except as may be required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

## DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of FortisBC listed below and filed with the securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this short form prospectus:

(a) audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2008 and 2007, together with the notes thereto and the auditors' reports thereon;

(b) management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2008;

(c) unaudited consolidated financial statements of the Corporation as at and for the three months ended March 31, 2009, together with the notes thereto;

(d) management's discussion and analysis of financial condition and results of operations of the Corporation for the three months ended March 31, 2009; and

(e) annual information form of the Corporation dated February 25, 2009.

Any document of the type referred to in the preceding paragraph, any material change reports (excluding confidential material change reports), any exhibits to unaudited interim or audited annual financial statements which contain updated earnings coverage information, any business acquisition reports and any other documents required to be incorporated by reference into this short form prospectus under the applicable securities laws of the provinces of Canada and subsequently filed by the Corporation with a securities commission or similar regulatory authority in Canada after the date of this short form prospectus and before the termination of any offering hereunder are deemed to be incorporated by reference into this short form prospectus.

**Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein, or in any other subsequently filed document that is also incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.**

**Upon a new annual information form and the related annual financial statements being filed by the Corporation with and, where required, accepted by the applicable securities regulatory authorities during the term of this prospectus, the previous annual information form, the previous annual financial statements and accompanying management's discussion and analysis, all interim financial statements and accompanying management's discussion and analysis and material change reports filed by the Corporation prior to the commencement of the financial year of the Corporation in which the new annual information form is filed shall be deemed no longer to be incorporated by reference into this short form prospectus for purposes of future offers and sales of MTN Debentures hereunder. Upon interim financial statements and the accompanying management's discussion and analysis being filed by the Corporation with the applicable securities regulatory authorities during the term of this short form prospectus, all interim financial statements and accompanying management's discussion and analysis filed prior to the new interim financial statements shall be deemed no longer to be incorporated into this short form prospectus for purposes of future offers and sales of MTN Debentures hereunder.**

Updated earnings coverage ratios will be filed quarterly with the applicable securities regulatory authorities in Canada, either as prospectus supplements or as exhibits to the Corporation's unaudited interim or audited annual financial statements, and will be deemed to be incorporated by reference into this short form prospectus for the purposes of future offers and sales of MTN Debentures hereunder.

This short form prospectus has been filed under securities laws that permit the specific variable terms for an issue of MTN Debentures to be determined after the prospectus is final and that permit the omission from this short form prospectus of that information. A pricing supplement or other prospectus supplement containing the specific variable terms for an offering of MTN Debentures will be delivered to purchasers of such MTN Debentures together with this short form prospectus and will be deemed to be incorporated by reference into this short form prospectus as of the date of such pricing supplement or other prospectus supplement only for the purposes of the offering of MTN Debentures to which that pricing supplement or other prospectus supplement pertains.

## THE CORPORATION

FortisBC is an integrated, regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a network of distribution assets, all of which are located in the southern interior of British Columbia. FortisBC serves, directly and indirectly, residential, general service, wholesale and industrial consumers of electricity located in the cities and rural regions of its service area. The Corporation has been in continuous operation since 1897.

FortisBC is an indirect wholly-owned subsidiary of Fortis Inc., a diversified, international distribution utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

## DETAILS OF THE OFFERING

The following is a summary of the material terms and conditions of the MTN Debentures and of the Indenture (as defined below). This summary does not purport to be complete and prospective investors are urged to read the Indenture in its entirety for the complete terms and conditions of the MTN Debentures and the Indenture. Immediately following its execution, the Principal Indenture (as defined below) will also be available at www.sedar.com. Certain capitalized terms used in the following summary are defined in " – Definitions" below.

### General

The MTN Debentures will be issued under a trust indenture to be dated May 27, 2009 (the "Principal Indenture") between the Corporation and Computershare Trust Company of Canada, as trustee (the "Trustee"). The Principal Indenture, as from time to time supplemented and amended by supplemental indentures, is herein called the "Indenture".

MTN Debentures may be issued from time to time in one or more series. The aggregate principal amount of all series of MTN Debentures which may be issued under the Indenture is unlimited.

The particular terms of each issue of MTN Debentures under this short form prospectus, as well as any modifications of or additions to the general terms of the MTN Debentures as described herein that may be applicable in the case of a particular issue of MTN Debentures, will be set forth in a pricing supplement or other prospectus supplement relating to that issue of MTN Debentures. Such specific terms include the aggregate principal amount of MTN Debentures offered, the currency, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), issue and delivery date, interest payment date(s), maturity date, and any redemption and sinking fund provisions. The Corporation reserves the right to set forth in a pricing supplement or other prospectus supplement specific terms of MTN Debentures which are not within the options and parameters set forth in this short form prospectus.

### Term and Denomination

The MTN Debentures will have maturities of not less than one year. Unless otherwise specified in the applicable pricing supplement or other prospectus supplement for a particular issue of MTN Debentures, each MTN Debenture will be denominated in Canadian dollars and all payments to be made on such MTN Debenture will be made in Canadian dollars.

### Interest

The MTN Debentures will bear interest, if any, from the date of issue at a fixed or floating rate as specified in the applicable pricing supplement or other prospectus supplement for a particular issue of MTN Debentures.

### Rank

Each MTN Debenture will be a direct, senior, unsecured and unsubordinated obligation of the Corporation, ranking equally, except as to sinking fund provisions applicable to different series of MTN Debentures, with all other MTN Debentures and all other present and future unsecured and unsubordinated Indebtedness of the Corporation.

### Global MTN Debentures

Unless otherwise provided in the applicable pricing supplement or other prospectus supplement for a particular issue of MTN Debenture, each series of MTN Debentures will be issued in "book-entry only" form and beneficial interests therein must be purchased or transferred through participants ("Participants"), which includes securities brokers and dealers, banks and other financial institutions, who participate directly in the book-entry registration and book-based securities transfer system administered by CDS Clearing and Depository Services Inc. (or such other person who is designated in writing by the Corporation to act as depository for the MTN Debentures) (the "Depository"). On the issue of MTN Debentures, the Corporation will cause a book-entry only global certificate evidencing those MTN Debentures (a "Global MTN Debenture") to be delivered to, and registered in the name of, the Depository or its nominee. Except as described below, no purchaser of a beneficial interest in the MTN Debentures will be entitled to a certificate or other instrument from the Corporation or the Depository evidencing that purchaser's interest therein, and no holder of a beneficial interest in the MTN Debentures will be shown on the records maintained by the Depository except through a Participant. The ability of a holder having a beneficial interest in the MTN Debentures outstanding in "book-entry only" form to pledge such interest or otherwise take action with respect to such interest (other than through a Participant) may be limited due to the lack of a physical certificate.

Any MTN Debentures issued to investors in the United States will, unless otherwise provided in the applicable pricing supplement or other prospectus supplement for a particular issue of MTN Debentures, also be issued in book-entry only form in the manner described above and the Global MTN Debenture representing such MTN Debentures issued to investors in the United States will be subject to certain restrictions on transfer set forth therein and in the Indenture and will bear a legend regarding such restrictions as described in the Indenture.

None of the Corporation, the Dealers, the Trustee nor any Paying Agent, if any, will have any responsibility or liability for any aspects of the records relating to, or payments made by any Depository or any Participant on account of the beneficial interests in, any Global MTN Debenture.

MTN Debentures represented by a Global MTN Debenture will be issued to beneficial owners in certificated form only if (a) the Depository notifies the Corporation that it is unwilling or unable to continue to act as depository in connection with the relevant Global MTN Debenture and the Corporation is unable to locate a qualified successor, (b) the Corporation determines that the Depository is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global MTN Debenture and the Corporation is unable to locate a qualified successor, (c) the Corporation executes and delivers to the Trustee a written order of the Corporation to the effect that all or a part of any Global MTN Debenture is to be exchanged for MTN Debentures in certificated form, (d) the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Corporation is unable to locate a qualified successor, (e) the Corporation determines that the MTN Debentures will no longer be held as book-entry only MTN Debentures through the Depository, (f) after the occurrence of an Event of Default, the Depository advises the Trustee that it received written notification from Participants, acting on behalf of beneficial owners representing, in the aggregate, more than 50% of the aggregate principal amount of outstanding MTN Debentures, that the continuance of the book-entry registration system in respect of the MTN Debentures is no longer in their best interest, or (g) the Corporation is required to do so by applicable law as determined by the Corporation.

The Indenture permits the Corporation and the Trustee to take such steps and execute such documents as are reasonably necessary to adopt or comply with changes to the book-entry system implemented by the Depository from time to time, including without limitation changes in the manner by which entitlement payments on account of Global MTN Debentures are made to the Depository and changes in deposit and custodial arrangements relating to Global MTN Debentures, whether in paper or electronic form. The Corporation may also issue Global MTN Debentures registered in the name of the Depository in uncertificated form in accordance with then applicable procedures of the Depository.

**Payment of Principal and Interest**

Payments of principal, interest and premium, if any, on each Global MTN Debenture will be made to the Depository or its nominee, as the case may be, as registered holder of such Global MTN Debenture. As long as the Depository or the nominee is the registered owner of a Global MTN Debenture, the Depository or the nominee, as the case may be, will be considered the sole owner of such Global MTN Debenture for the purposes of receiving payment on the Global MTN Debenture and, except as required by law, for all other purposes under the Indenture and such Global MTN Debenture.

The Corporation expects that the Depository or its nominee, upon receipt of any payment of principal or interest in respect of a Global MTN Debenture, will credit Participants' accounts, on the date principal or interest is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global MTN Debenture as shown on the records of the Depository or the nominee. The Corporation also expects that payments of principal and interest by Participants to the owners of beneficial interests in such Global MTN Debentures held through Participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of Participants. The responsibility and liability of the Corporation and the Trustee in respect of MTN Debentures represented by Global MTN Debentures is limited to making payment of any principal and interest due on such Global MTN Debentures to the Depository or its nominee.

**Transfer of MTN Debentures**

Transfers of beneficial ownership of MTN Debentures represented by a Global MTN Debenture will be effected through the clearing, depository and entitlement services maintained by the Depository or its nominee for such Global MTN Debenture (with respect to interests of Participants) and through the records of Participants (with respect to interests of persons other than Participants). Beneficial owners of MTN Debentures represented by Global MTN Debentures who are not Participants but who desire to purchase, sell or otherwise transfer ownership of or other interest in MTN Debentures may do so only through Participants.

**Redemption and Purchase for Cancellation**

If specified in the applicable pricing supplement or other prospectus supplement for a particular series of MTN Debentures, that series of MTN Debentures may be redeemed at the option of the Corporation, in whole at any time or in part from time to time, on the terms and conditions so specified and otherwise in accordance with the Principal Indenture.

The Corporation may at any time purchase all, or from time to time any, of the outstanding MTN Debentures in the market, by tender or by private contract. Any MTN Debentures purchased by the Corporation will be cancelled and not be reissued.

### Certain Covenants of the Corporation

The Indenture contains, among other things, covenants and provisions applicable so long as any of the MTN Debentures are outstanding, substantially to the following effect:

#### *Negative Pledge*

Except for Permitted Liens (which include the Liens in favour of the secured debentures outstanding under the Secured Trust Deed), the Corporation will not, and will ensure that no Subsidiary will, directly or indirectly, create, incur, assume or suffer to exist any Lien to secure Indebtedness on any of its present or future property or assets or any income or profits therefrom, or assign or convey any right (other than a Permitted Lien) to receive income therefrom to secure any Indebtedness, unless (a) if such Lien secures Indebtedness that ranks in priority to or *pari passu* with the MTN Debentures, the MTN Debentures (and if the Corporation so elects, any other Indebtedness of the Corporation ranking at least *pari passu* with the MTN Debentures) are secured on an equal and rateable basis with the obligations so secured until such time as such Indebtedness is no longer secured by such Lien, or (b) if such Lien secures Subordinated Debt, any such Lien will be subordinated to a Lien granted to the MTN Debenture holders to the same extent as such Subordinated Debt is subordinated to the MTN Debentures.

In addition to the Permitted Liens, the Corporation or any Subsidiary may create, incur, assume or suffer to exist any Lien that secures an aggregate amount of Indebtedness which, together with Indebtedness of any Subsidiary (whether or not secured) other than (a) Indebtedness of Subsidiaries which is Non-Recourse Debt and (b) unsecured Indebtedness of a Subsidiary that has irrevocably and unconditionally guaranteed the obligations of the Corporation under the MTN Debentures and which unsecured Indebtedness is subordinate to or *pari passu* with the obligations of such Subsidiary under such guarantee, does not at any time exceed 5% of Consolidated Net Worth.

#### *Limitations on Funded Obligations*

The Corporation will not, and will ensure that no Subsidiary will, incur, issue, assume, guarantee or otherwise become liable directly or indirectly for any Funded Obligation, unless (a) after giving effect thereto, the aggregate principal amount of Consolidated Funded Obligations does not exceed 75% of Total Consolidated Capitalization, calculated on a *pro forma* basis, and (b) no Default or Event of Default shall have occurred and be continuing under the Indenture at the time of, or will occur as a consequence of, such Funded Obligation having been incurred, issued, assumed, guaranteed or otherwise becoming a liability of the Corporation or any Subsidiary. For purposes of such calculation, Consolidated Funded Obligations will not include Permitted Financial Instrument Obligations having an aggregate net amount due or accruing due thereunder, determined by marking each such obligation to market at the time of determination, of not more than $30 million (Index Linked) but, for greater certainty, shall include the aggregate net amount due or accruing due in excess of $30 million (Index Linked) under all such Permitted Financial Instrument Obligations. Solely for this purpose, all Indebtedness incurred, issued, assumed or guaranteed by, or otherwise becoming a liability of, a Subsidiary (but, for greater certainty, excluding trade payables of such Subsidiary incurred in the ordinary course of such Subsidiary's business) shall be deemed to be a Funded Obligation of such Subsidiary regardless of the actual term of such Indebtedness and regardless of whether or not such Indebtedness of such Subsidiary is Subordinated Debt.

#### *Limitations on Subsidiary Funded Obligations*

The Corporation will ensure that no Subsidiary will issue any Funded Obligations, other than (a) Funded Obligations that are Non-Recourse Debt and (b) if the Subsidiary is directly or indirectly wholly-owned by the Corporation, Funded Obligations to the Corporation.

#### *Limitations on Successor Corporations*

The Corporation will not enter into any transaction or series of transactions in which all or substantially all of its property and assets would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless (a) either the Corporation is the surviving entity, or the entity formed by the amalgamation or consolidation or into which the Corporation is merged, or that acquires all or substantially all of the property and assets of the Corporation, is a corporation, partnership or trust organized and validly existing under the laws of Canada or any of its provinces or territories and expressly assumes all the obligations of the Corporation under the Indenture, all MTN Debentures and any supplemental indentures (a "Successor Entity") and (b) no Default or Event of Default is continuing or will occur as a result of such transaction.

***Limitation on Financial Instrument Obligations***

The Corporation will not enter into any Financial Instrument Obligation except for risk management purposes in the ordinary course of and related to the business of the Corporation and its Subsidiaries and not simply as a matter of speculation.

***Restriction on Business***

The Corporation (directly or through its Subsidiaries) will not engage in any business not regulated by the BCUC, other than a business related or ancillary to a type of business regulated by the BCUC.

***Related Party Transactions***

The Corporation will not, and will ensure that no Subsidiary will, directly or indirectly, engage in any transaction with any affiliate on terms that are less favourable to the Corporation or such Subsidiary than with an unrelated third party; provided, however, that this restriction shall not apply in respect of any transfer by the Corporation to any subsidiary of Fortis Inc. of all or any part of West Kootenay Power Ltd., ESI Power-Walden Corporation Ltd. or the Walden Power Partnership. The Corporation holds a 99.999% interest in the Walden Power Partnership. West Kootenay Power Ltd. is a wholly owned subsidiary of the Corporation and holds the remaining 0.001% interest in the Walden Power Partnership. ESI Power-Walden Corporation is a wholly owned subsidiary of the Corporation and owns certain of the assets used by the Walden Power Partnership in the operation of the 16 megawatt Walden power plant.

***Subsidiaries***

The Corporation will create and maintain Subsidiaries only for the purpose of carrying on a business or undertaking that is related to or ancillary to the business of the Corporation. In addition, the Corporation will not (a) directly or indirectly, guarantee or secure or become contingently liable for in any manner any Indebtedness of a Subsidiary, other than by way of delivery of letters of credit or guarantees from the Corporation in favour of an independent system operator or as it may otherwise be directed by the BCUC in connection with any regulated business of the Subsidiary, in which event the face amount of such letter of credit or equivalent amount of guarantee (regardless of the actual term thereof) will be included as a Funded Obligation of the Corporation for all purposes of the Indenture, or (b) provide a loan to a Subsidiary unless such Subsidiary is a wholly-owned direct or indirect Subsidiary of the Corporation. Notwithstanding the foregoing, the Corporation may guarantee or secure or become contingently liable for the Walden Indebtedness.

**Events of Default**

The occurrence of any one or more of the following will constitute an Event of Default under the Indenture:

(a) if the Corporation defaults in payment of any principal or premium, if any, on any MTN Debentures when the same becomes due and payable (including, for greater certainty, a default in payment relating to a redemption of all or part of such MTN Debentures) and such default continues for a period of five Business Days;

(b) if the Corporation defaults in payment of any interest on any MTN Debentures when the same becomes due and payable and such default continues for a period of 30 days;

(c) if the Corporation fails to comply with its covenant described under "— Limitations on Successor Corporations" above;

(d) if the Corporation neglects to observe or perform in any material respect any covenant or condition (other than those referred to in paragraphs (a), (b) and (c) above) contained in the Indenture or any MTN Debenture on its part to be observed or performed and, after notice in writing has been given by the Trustee to the Corporation (which notice the Trustee may, in its discretion, independently provide and shall provide upon receipt of a Holders' Request) specifying such default and requiring the Corporation to remedy such default, the Corporation fails to remedy such default within a period of 60 days unless the Trustee, having regard to the subject matter of the default, agrees to give the Corporation a longer period of time within which to cure such default, and in such event, within the period agreed to by the Trustee;

(e) if any representation or warranty made by the Corporation in the Indenture, in any MTN Debenture or in any supplemental indenture or in any document or certificate provided to the Trustee or the holders of MTN Debentures pursuant to the provisions of the Indenture or an MTN Debenture is proven to be incorrect in any material respect, unless such incorrect representation or warranty is capable of being corrected and the Corporation cures such default within a period of 60 days following the receipt of written notice from the Trustee (which notice the Trustee may, in its discretion, independently provide and shall provide upon receipt of a Holders' Request) specifying the incorrect representation and warranty, unless the Trustee, having regard to the subject matter of the breach, agrees to give the Corporation a longer period of time within which to cure such default, and in such event, within the period agreed to by the Trustee;

(f) if at any time a default is made by the Corporation or any Subsidiary, whether as primary obligor or guarantor or surety, with respect to any Indebtedness (excluding amounts due to the holders under the MTN Debentures and, with respect to the Walden Power Partnership, excluding the Walden Indebtedness), where the aggregate principal amount of such Indebtedness exceeds an amount equal to 5% of Consolidated Net Worth at such time and such default continues to exist beyond any applicable cure period as a result of which such Indebtedness is accelerated; provided that if the default is cured prior to acceleration of the MTN Debentures, then the Event of Default will be deemed to have been cured;

(g) if the Corporation becomes insolvent, makes any assignment in bankruptcy or makes any other assignment for the benefit of creditors, makes any proposal under the *Bankruptcy and Insolvency Act* (Canada) or any comparable law, seeks relief under the *Companies' Creditors Arrangement Act* (Canada), the *Winding Up and Restructuring Act* (Canada) or any other bankruptcy, insolvency or analogous law, has a trustee, receiver, receiver and manager, interim receiver, custodian, sequestrator or other person with similar powers appointed over all or any substantial portion of its assets, or files a petition or otherwise commences any proceeding seeking any reorganization, arrangement, composition or readjustment under any applicable bankruptcy, insolvency, moratorium or other similar law affecting creditors' rights or consents to, or acquiesces in, the filing of such a petition;

(h) if a proceeding is instituted against the Corporation with respect to the appointment of a liquidator, trustee in bankruptcy, custodian, receiver or receiver and manager or other person with similar powers with respect to the Corporation or any material part of the property of the Corporation and such proceeding has not been dismissed, discharged, stayed or restrained within 60 days of the institution thereof, provided that during such 60-day period the proceeding is being defended in good faith by the Corporation and the position of the holders of MTN Debentures is not being prejudiced in any material respect;

(i) if an encumbrancer takes possession of property of the Corporation or Subsidiaries that constitutes a substantial part of the property of the Corporation considered on a consolidated basis, or any execution is levied or enforced upon property that constitutes a substantial part of the property of the Corporation considered on a consolidated basis, which execution remains unsatisfied for such period of time as would permit such property to be sold thereunder unless such execution is in good faith being contested by the Corporation or its Subsidiaries and enforcement and any other action or proceeding relating to such execution has been stayed pending the outcome of such contest; or

(j) the rendering at any time by a court or courts of competent jurisdiction of a final judgment or judgments against the Corporation or any Subsidiary (other than a Subsidiary whose only Indebtedness is Non-Recourse Debt and whose only material asset is the property to which such Non-Recourse Debt has recourse in the event of a default in its repayment) in an aggregate amount in excess of the lesser of (i) $50.0 million (Index Linked) and (ii) 10% of the Consolidated Net Worth of the Corporation at such time, which judgment or judgments are not subject to any further appeal by the Corporation or such Subsidiary or in respect of which the applicable period in which an appeal may be commenced by the Corporation or such Subsidiary has expired and which judgment or judgments remain unpaid, unvacated or unstayed for a period of 60 days.

Upon the occurrence of an Event of Default that is continuing, the Trustee may in its discretion, and will upon receipt of a Holders' Request, declare the principal of and interest on all MTN Debentures then outstanding and any other moneys payable under the Indenture to be due and payable immediately. Notwithstanding the preceding sentence, if an Event of Default occurs and is continuing pursuant to paragraph (g) or (h) above, the principal of and interest on the MTN Debentures then outstanding and any other moneys payable under the Indenture will be due and payable immediately without demand or notice of any kind. Upon such acceleration, the Corporation shall forthwith pay to the Trustee for the benefit of the holders of MTN Debentures the principal of, and accrued and unpaid interest, and premium, if any (calculated as if such MTN Debentures were being redeemed and the redemption date was the date such amounts become due and payable), together with interest at the rate borne by the MTN Debentures on such principal, interest and such other moneys from the date of such declaration until payment is received by the Trustee.

**Modification and Waiver**

The Indenture will require the consent of the holders of 100% of the outstanding principal amount of the MTN Debentures of a particular series to amend the terms of the MTN Debentures of such series which affect the interest rate, the timing, currency, amount or other terms relating to the payment of interest, principal, premium or the applicable redemption price or the terms of repayment, redemption or maturity of such series of MTN Debentures. The Indenture will require the consent of the holders of 100% of the outstanding principal amount of all Debentures to amend the percentage required to make amendments or waivers to other terms and conditions of the Indenture. The consent of the holders of at least 66 2/3% of the outstanding principal amount of all MTN Debentures then outstanding or 66 2/3% of the principal amount of MTN Debentures represented at a meeting of the holders of MTN Debentures at which a quorum is present will be required to amend or waive other terms and conditions, including a waiver of any Default or Event of Default and a cancellation of any declaration to make all amounts outstanding immediately due and payable.

**Trustee**

Computershare Trust Company of Canada will serve as the trustee, registrar and paying agent under the Indenture.

**Governing Law**

The MTN Debentures and the Indenture will be governed by and construed in accordance with the laws of the Province of British Columbia and the federal laws of Canada applicable therein.

**Definitions**

The following defined terms used in this section of this short form prospectus will be defined in the Indenture substantially as set out below:

"*BCUC*" means the British Columbia Utilities Commission, an independent quasi-judicial regulatory agency that operates under and administers the *Utilities Commission Act* and is responsible for, among other things, the regulation of British Columbia's electricity industry, and includes any successor body or agency thereto;

"*Brilliant Terminal Agreement*" means the Brilliant Terminal Station Facilities Interconnection and Investment Agreement entered into with Columbia Power Corporation and the Columbia Basin Trust in 2002 relating to the engineering, design, procurement, construction, maintenance and ownership of a common substation near the Brilliant hydroelectric generating plant, as the same may be amended, supplemented, restated or replaced from time to time;

"*Business Day*" means a day, other than a Saturday or Sunday, on which banks in Toronto, Ontario, Vancouver, British Columbia and Kelowna, British Columbia are generally open for business and are not authorized or obligated by law to close;

"*Capital Lease Obligation*" means the obligation of the Corporation or a Subsidiary, as lessee, to pay rent or other payment amounts under a lease or similar arrangement relating to real or personal property which is required to be classified and accounted for as a capital lease or liability in accordance with GAAP, and for purposes of the Indenture the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with GAAP; provided that the Brilliant Terminal Agreement and any other lease or similar arrangement in respect of real or personal property that the Corporation or any of its Subsidiaries is not required to classify and account for as a Capital Lease Obligation pursuant to an order or similar authorization of the BCUC shall not be classified as a Capital Lease Obligation for the purposes of the Indenture;

"*Common Shares*" means shares of any class or classes of the share capital of a corporation or securities representing ownership interests in any person other than a corporation, the rights of the holders of which to participate in the distribution of assets upon the voluntary or involuntary liquidation, dissolution or winding-up of such corporation or other person are not restricted to a fixed sum or to a fixed sum plus accrued dividends or other periodic distributions;

"*Consolidated Funded Obligations*" means the aggregate amount of Funded Obligations of the Corporation and its Subsidiaries determined on a consolidated basis in accordance with GAAP;

"*Consolidated Net Worth*" means the Shareholders' Equity of the Corporation and its Subsidiaries determined on a consolidated basis in accordance with GAAP;

"*Contingent Liability*" means any agreement, undertaking or arrangement by which any person (a) guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Indebtedness of any other person (other than by endorsements of instruments in the course of collection), or (b) guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any person's obligation under any Contingent Liability shall (subject to any limitation set forth therein) be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

"*Default*" means any event which, after giving notice, or passage of time, or both, would constitute an Event of Default;

"*Event of Default*" means any of the events described under "— Events of Default" above;

"*Financial Instrument Obligations*" means, with respect to any person, obligations arising under any agreement relating to derivatives, including:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time;

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity, but for greater certainty excludes any agreement where the person is delivering or taking delivery of the applicable commodity; and

(d) any other derivative transaction, including any option to enter into any of the foregoing, or any combination of the foregoing,

provided that the amount of any Financial Instrument Obligation is the net amount due or accruing due under the agreement governing such obligation, determined by marking such obligation to market at the time of determination in accordance with its terms;

"*Funded Obligations*" means, as at any date, with respect to the Corporation or a Subsidiary, all Indebtedness created, assumed or guaranteed by the Corporation or such Subsidiary, as applicable, other than Subordinated Debt and all Indebtedness which matures by its terms on, or is renewable at the option of the debtor to, a date not more than 18 months after the date of the original creation, assumption or guarantee thereof;

"*GAAP*" means, at any time, generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants or any successor body, as modified from time to time by regulatory directives of the BCUC;

"*holder*" means, when used with respect to any MTN Debenture at any particular time, the person in whose name the MTN Debenture is registered at such time in the register of MTN Debentures maintained by the Trustee;

"*Holders' Request*" means an instrument requesting the Trustee to take or refrain from taking some action or proceeding specified therein, signed in one or more counterparts by the holder or holders representing not less than 25% of the total principal amount of all MTN Debentures, or if applicable, any series of MTN Debentures, then outstanding;

"*Indebtedness*" means, with respect to a person, without duplication:

(a) all obligations of such person in respect of borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments, but excluding (i) Preferred Securities issued by such person, (ii) trade payables of such person incurred in the ordinary course of business and (iii) Prudential and Credit Support Obligations;

(b) all Financial Instrument Obligations (other than Prudential and Credit Support Obligations);

(c) all obligations issued or assumed by such person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(d) all Purchase Money Obligations and Capital Lease Obligations; and

(e) all Contingent Liabilities of such person in respect of any of the foregoing;

"*Index Linked*", with respect to any amount at any time, means that the amount is adjusted as at each April 1 commencing April 1, 2010 by multiplying the amount by the fraction which has as numerator the Inflation Index as at the immediately preceding January and as denominator the Inflation Index for the month of January 2009;

"*Inflation Index*" means the Consumer Price Index for All-Items in British Columbia as published by Statistics Canada or, if such index in its present form becomes unavailable, such similar index as may be proposed by the Corporation and approved by the Trustee, acting reasonably (and for this purpose the Trustee may rely upon advice from counsel or other qualified professional) or failing such approval as determined by arbitration pursuant to the *Commercial Arbitration Act* (British Columbia);

"*Liens*" means, with respect to any property or assets, any security interest, mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge, assignment, adverse claim, defect of title in, on or of such property or assets, the interest of a vendor or a lessor under any conditional sales contract, hire-purchase agreement, chattel mortgage, title retention agreement or capital lease (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such property or assets and any other arrangement having the effect of providing security;

"*MTN Debentures*" means the Medium Term Note Debentures of the Corporation issued, certified and outstanding under the Indenture from time to time;

"*Non-Recourse Debt*" means, with respect to a Subsidiary, any Indebtedness incurred by a Subsidiary for the purpose of acquiring, repairing, altering, constructing or developing any real or tangible personal property and in respect of which recourse, in the event of a default in the repayment of such Indebtedness, is limited to such property (including all rights and benefits related to or arising out of such property) and includes any extension, renewal or refunding of any such Indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"*Paying Agent*" means any person, which may include the Trustee, authorized by the Corporation to pay the principal of and premium, if any, and interest on any MTN Debentures on behalf of the Corporation;

"*Permitted Financial Instrument Obligations*" means Financial Instrument Obligations that the Corporation is permitted to enter into pursuant to the Indenture for risk management purposes in the ordinary course of and related to the business of the Corporation and its Subsidiaries and not simply as a matter of speculation;

"*Permitted Liens*" means, as at any particular time, any of the following Liens:

(a) Liens for Taxes, rates, assessments or governmental charges or levies which are not due or delinquent or which are due and delinquent but the validity of which is being contested in good faith and in respect of which appropriate provision is made in the Corporation's consolidated financial statements in accordance with GAAP;

(b) Liens imposed by law (such as builders', carriers', warehousemen's, landlords', mechanics' and materialmen's Liens) which arise in the ordinary course of business and relate to obligations not yet due or delinquent or the validity or amount of which are being contested in good faith and in respect of which adequate provision for payment has been made; any Lien arising out of judgments or awards with respect to which the Corporation or a Subsidiary is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review (provided no Event of Default has resulted therefrom); or undetermined or inchoate Liens incidental to current operations which have not at such time been filed pursuant to law against the Corporation or any Subsidiary or which relate to obligations not due or delinquent;

(c) any encumbrance affecting real property, such as easements, title irregularities, encroachments, rights-of-way, servitudes or other encumbrances of a nature similar to the foregoing, granted to or reserved by other persons which do not in the aggregate materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary and mortgages of and other Liens against any such encumbrance;

(d) the rights reserved to or vested in municipalities or governmental or other public authorities (whether by statutory provisions or otherwise) to terminate leases, licences, franchises, grants or permits or to require annual or other periodic payments as a condition of the continuance thereof;

(e) reservations in any original grants from the Crown of any land or interest therein, statutory exceptions to title, and reservations of mineral rights (including coal, oil and natural gas) in any grants from the Crown or from any other predecessors in title;

(f) security given by the Corporation or any Subsidiary to public utilities or to any municipalities or governmental or other public authorities when required by the utility, municipality, governmental or other public authority in connection with the supply of services or utilities to the Corporation or such Subsidiary, or security otherwise required by the BCUC to be given by the Corporation or any Subsidiary to the BCUC or any other person;

(g) plans of subdivision, site plans, municipal agreements, zoning or other restrictive covenants affecting the use of real property or interests therein provided that such plans, agreements, zoning or covenants are complied with and do not in the aggregate materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary;

(h) Liens or good faith deposits arising in connection with bids, tenders or contracts entered into in the ordinary course of business;

(i) deposits of cash or securities in connection with any Lien referred to in this definition which is being contested or otherwise sought to be removed in good faith by the Corporation or any Subsidiary;

(j) rights and interests created by notice registered by any department of highways or any similar authority with respect to proposed highways, which do not materially adversely affect the value or the use of the property for the purposes for which it is held by the Corporation or a Subsidiary;

(k) certificates of pending litigation that may be registered against any real property or interests therein of the Corporation or a Subsidiary in respect of any action or proceeding against the Corporation or such Subsidiary, but with respect to which action or proceeding no judgment, award or attachment against the Corporation or such Subsidiary has been granted or made and which the Corporation or such Subsidiary is defending in good faith and in respect of which appropriate provision is made in the Corporation's consolidated financial statements in accordance with GAAP;

(l) any Lien in connection with the granting by the Corporation or a Subsidiary in the ordinary course of its business of any lease, sublease, tenancy or right of occupancy to any person in respect of property owned or leased by the Corporation or such Subsidiary; any Lien or right of distress reserved in or exercisable under any lease entered into by the Corporation or any Subsidiary for rent and for compliance with the terms of that lease including, without limitation, Liens under the terms of the Brilliant Terminal Agreement;

(m) Purchase Money Security Interests and any Lien which is created, issued or assumed by the Corporation or any Subsidiary to secure a Capital Lease Obligation;

(n) any Lien on a property or asset acquired by the Corporation or any Subsidiary that secures the obligations of a person, whether or not that obligation is assumed by the acquiring person, which Lien exists before and at the time that property or asset is acquired and which (i) was not incurred in contemplation of, or as a result of, that property or asset being acquired and (ii) is not applicable to the Corporation or any Subsidiary or the properties or assets of the Corporation or any Subsidiary other than the property or asset so acquired;

(o) any deposit, margin account, letter of credit or similar Lien to secure obligations under Permitted Financial Instrument Obligations;

(p) any Lien granted by a Subsidiary in favour of the Corporation and any Lien on an asset created or assumed by a Subsidiary to secure Non-Recourse Debt of such Subsidiary in respect of such asset;

(q) any Lien granted by the Corporation or a Subsidiary to secure Indebtedness payable on demand or maturing within 18 months of the date that such Indebtedness is incurred or of the date of any renewal or extension of such Indebtedness;

(r) any Lien granted by the Corporation or a Subsidiary with the prior written consent of the Trustee or the holders of the MTN Debentures, acting reasonably;

(s) the Secured Trust Deed Liens and the Walden Liens; and

(t) Liens in favour of operators of other facilities in connection with shared facilities and transmission assets agreements, which facilities and transmission assets are subject to regulation by the BCUC;

"*Preferred Securities*" means (a) Securities which on the date of issue thereof by a person (i) have a term to maturity of more than 30 years, (ii) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of such person outstanding on such date, (iii) entitle such person to satisfy the obligation to pay the principal or face amount thereof by issuing Common Shares, (iv) entitle such person to defer the payment of interest thereon for more than four years without causing an event of default to occur and (v) entitle such person to satisfy the obligation to make payments of interest thereon by issuing Common Shares and (b) shares of any class in the capital of a corporation or Securities representing ownership interests in any person other than a corporation which, in either case, are not Common Shares;

"*Prudential and Credit Support Obligations*" means all contingent obligations of the Corporation or its Subsidiaries relating to letters of credit, guarantees and other financial instruments incurred, provided or assumed by the Corporation or its Subsidiaries in the ordinary course of business to satisfy or otherwise comply with prudential and credit support arrangements required or approved by the BCUC or any governmental authority;

"*Purchase Money Obligation*" means any unpaid part of or Indebtedness issued, incurred or assumed to finance all or part of the cost of acquiring any real or tangible personal property, including installation costs and expenditures made for any repairs, alterations, construction, development or improvements performed thereon or thereto; provided that the Indebtedness is issued, incurred or assumed within 12 months following the acquisition of such property or the completion of the installation, repairs, alterations, construction, development or improvements thereto or thereon, and includes any extension, renewal or refunding of any such Indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"*Purchase Money Security Interest*" means any Lien on real or tangible personal property which is created, issued or assumed by the Corporation or any Subsidiary to secure the Purchase Money Obligation in respect of such property and includes any extension, renewal or refunding thereof so long as the principal amount outstanding on the date of such extension, renewal or refunding is not increased; provided that such Lien is limited to the property acquired in connection with the issuance, incurring or assumption of such Purchase Money Obligation;

"*Secured Trust Deed*" means the deed of trust and mortgage made as of March 15, 1983 between the Corporation and The Canada Trust Company (since replaced by Computershare Trust Company of Canada), as trustee;

"*Secured Trust Deed Indebtedness*" means, at any time, the Indebtedness owing by the Corporation at such time under the Secured Trust Deed in respect of the 11% Secured Debentures, Series E due December 1, 2009, the 9.65% Secured Debentures, Series F due October 16, 2012 and the 8.80% Secured Debentures, Series G due August 28, 2023;

"*Secured Trust Deed Liens*" means Liens against any property or assets of the Corporation providing security for obligations of the Corporation under the Secured Trust Deed Indebtedness;

"*Securities*" means any stock, shares, units, instalment receipts, voting trust certificates, bonds, debentures, notes, other evidences of indebtedness, or other documents or instruments commonly known as securities or any certificates of interest, shares or participations in, temporary or interim certificates for, receipts for, guarantees of, or warrants, options or rights to subscribe for, purchase or acquire, any of the foregoing;

"*Shareholders' Equity*" means (a) in respect of a corporation, the aggregate amount of shareholders' equity (including Common Share capital, preferred share capital if issued directly by the corporation, contributed surplus and retained earnings) as shown on the most recent quarterly or annual balance sheet of such corporation calculated in accordance with GAAP and (b) in respect of any entity other than a corporation (including a partnership), the aggregate amount of equity (including partnership equity) as shown on the most recent quarterly or annual balance sheet of such entity calculated in accordance with GAAP;

"*Subordinated Debt*" means Indebtedness which would be Preferred Securities within the meaning of clause (a) of the definition of Preferred Securities but without regard to their term to maturity and Indebtedness which, pursuant to the terms of a subordination agreement entered into with the Trustee (a) is subordinated in all rights to senior Indebtedness, (b) has no contractual rights of acceleration until at least 180 days following a Default or an Event of Default while any senior Indebtedness remains outstanding, (c) does not permit any prepayments or any payments to be made in respect thereof at any time when monies are due and payable with respect to senior Indebtedness and (d) in the event of any insolvency, bankruptcy, receivership, liquidation, arrangement, reorganization or other similar proceeding, is paid only after all senior Indebtedness has been paid in full;

"*Subsidiary*" means:

(a) any corporation of which Securities, having by the terms thereof ordinary voting power to elect a majority of the board of directors of such corporation (irrespective of whether at the time shares of any other class or classes of such corporation might have voting power by reason of the happening of any contingency, unless the contingency has occurred and then only for as long as it continues), are at the time directly, indirectly or beneficially owned or controlled by the Corporation or one or more of its Subsidiaries, or the Corporation and one or more of its Subsidiaries;

(b) any partnership of which the Corporation or one or more of its Subsidiaries, or the Corporation and one or more of its Subsidiaries: (i) directly, indirectly or beneficially owns or controls more than 50% of the income, capital, beneficial or ownership interest (however designated) thereof; and (ii) is a general partner, in the case of a limited partnership, or is a partner that has the authority to bind the partnership in all other cases; or

(c) any other person of which at least a majority of the income, capital, beneficial or ownership interest (however designated) is at the time directly, indirectly or beneficially owned or controlled by the Corporation or one or more of its Subsidiaries, or the Corporation and one or more of its Subsidiaries;

"*Taxes*" means all taxes, charges, fees, levies, imposts and other assessments, including all income, sales, use, goods and services, value added, capital, capital gains, alternative, net worth, transfer, profits, withholding, payroll, employer health, excise, real property and personal property taxes, and any other taxes, customs duties, fees, assessments or similar charges in the nature of a tax, including Canada Pension Plan and Quebec Pension Plan contributions, employment insurance payments and workers' workplace, health, safety and compensation premiums, together with any instalments with respect thereto, and any interest, fines and penalties with respect thereto, imposed by any governmental authority (including federal, provincial, municipal and foreign governmental authorities), and whether disputed or not;

"*Total Consolidated Capitalization*" means, as at any date, with respect to the Corporation, without duplication, the sum of: (a) Consolidated Net Worth, (b) the principal amount of all Preferred Securities (for certainty, without duplication of Preferred Securities included in Consolidated Net Worth), (c) the principal amount of all Consolidated Funded Obligations and (d) the principal amount of all Subordinated Debt, as determined on a consolidated basis in accordance with GAAP;

"*Walden Indebtedness*" means the indebtedness of no more than $7.048 million principal amount owing by the Walden Power Partnership under a loan agreement dated October 15, 1993 and made among the Walden Power Partnership (in which the Corporation has a general partnership interest), as borrower, ESI Power-Walden Corporation Ltd., West Kootenay Power Ltd. and The Mutual Life Assurance Company of Canada, as lender; and

"*Walden Liens*" means the pledge by the Corporation of all of its partnership interests and units in Walden Power Partnership pursuant to a pledge and security agreement made September 30, 1994 between the Corporation and The Mutual Life Assurance Company of Canada and the mortgage of certain real property as security for the Walden Indebtedness.

## RATINGS

The MTN Debentures are expected to be rated BBB (high), stable trend, by DBRS Limited ("DBRS"), and Baa2, stable outlook, by Moody's Investors Service ("Moody's").

Ratings are not recommendations to purchase, hold or sell securities, because ratings do not comment as to market price or suitability for a particular investor. The Corporation understands that ratings are based on, among other things, information furnished to the rating agencies by the Corporation and information obtained by the rating agencies from public sources. Ratings may be changed, suspended or withdrawn as a result of changes in, or unavailability of, that information.

DBRS's long-term debt ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. DBRS states that its long-term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner with respect to both interest and principal commitments. DBRS ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment decision making process. Every DBRS rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of BBB by DBRS is in the middle of three subcategories and within the fourth highest of nine major categories. A credit rating of BBB is generally an indication of adequate credit quality as defined by DBRS. Protection of interest and principal is considered acceptable, but the entity is considered to be fairly susceptible to adverse change in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

Moody's long-term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's long-term debt ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. According to Moody's, a rating of Baa is the fourth highest of nine major categories; such a debt rating is assigned to debt instruments considered to be medium-grade. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics.

## EARNINGS COVERAGE RATIOS

The following earnings coverage ratios have been calculated for the twelve month periods ended December 31, 2008 and March 31, 2009. The following ratios do not give effect to the issue of any MTN Debentures pursuant to this short form prospectus since the aggregate principal amount of MTN Debentures that will be issued hereunder and the terms of the issue are not currently known. The ratio for the twelve month period ended March 31, 2009 is based on unaudited financial information.

| | Twelve Months Ended December 31, 2008 | Twelve Months Ended March 31, 2009 |
|---|---|---|
| | *(dollars in thousands)* | |
| **Earnings coverage** | | |
| Earnings before interest and income tax | $70,357 | $72,674 |
| Interest requirements | $32,413 | $32,465 |
| Interest coverage | 2.17 times | 2.24 times |

Subsequent to the date of this short form prospectus, updated earnings coverage ratios will be filed quarterly by the Corporation with applicable securities regulatory authorities, either as prospectus supplements or exhibits to the unaudited interim or audited annual financial statements of the Corporation, and will be deemed to be incorporated by reference into this short form prospectus for the purpose of future offerings of MTN Debentures.

## USE OF PROCEEDS

The MTN Debentures will be issued from time to time at the discretion of the Corporation in an aggregate principal amount not to exceed $300,000,000 during the 25 month period that this short form prospectus, including any amendments hereto, remains valid. The net proceeds to be received by the Corporation from the sale of MTN Debentures under this short form prospectus will be the issue price thereof less any commissions payable to the Dealers and expenses paid in connection therewith. The net proceeds cannot be estimated at the date hereof since the amount thereof will depend on the terms and conditions of the MTN Debentures and the extent to which MTN Debentures are issued under this short form prospectus. Unless otherwise specified in a prospectus supplement or pricing supplement, the net proceeds will be used for general corporate purposes, including repayment of existing indebtedness and financing the Corporation's capital expenditure program and working capital requirements.

Proceeds from the sale of MTN Debentures may be used to reduce indebtedness which the Corporation may have with one or more Canadian chartered banks which are related to a Dealer. See "Relationship Between FortisBC and Certain Dealers".

## PLAN OF DISTRIBUTION

The MTN Debentures may be offered severally by any one or more of the Dealers pursuant to the Dealer Agreement. The MTN Debentures may be sold from time to time by the Dealers acting as agents of the Corporation. The MTN Debentures may also be purchased from time to time by any of the Dealers, as underwriter or dealer purchasing as principal, at such prices as may be agreed upon between the Corporation and such Dealer, for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. The Dealers may, on behalf of the Corporation, solicit offers to purchase the MTN Debentures at such prices as may be established from time to time by consultation between the Corporation and the Dealers and with such commissions as set forth in the Dealer Agreement or as are agreed to between the Corporation and the Dealers. Each Dealer's compensation will be increased or decreased by the amount by which the aggregate price paid for MTN Debentures by purchasers exceeds or is less than the gross proceeds paid by the Dealer, when purchasing as principal, to the Corporation. The MTN Debentures may also be offered directly to the public by the Corporation pursuant to applicable statutory or discretionary exemptions at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commission will be paid to the Dealers. The terms and conditions of any sale or sales of MTN Debentures will be determined at the time of such sale or sales and disclosed in the applicable pricing supplement.

The MTN Debentures have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "1933 Act") or any state securities laws and may not be offered or delivered, directly or indirectly, or sold in the United States except in certain transactions exempt from the registration requirements of the 1933 Act and in compliance with any applicable state securities laws. The Dealers have agreed that they will not offer or sell the MTN Debentures so as to require registration thereof or filing of a prospectus in any jurisdiction other than the provinces of Canada, including the United States. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the MTN Debentures in the United States. In addition, until 40 days after the commencement of the offering of any MTN Debentures, an offer or sale of any such MTN Debentures within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the 1933 Act if such offer is made otherwise than in accordance with an applicable exemption from the registration requirements of the 1933 Act.

In connection with any offering of MTN Debentures, the Dealers may, subject to applicable laws, over-allot or effect transactions which stabilize or maintain the market price of the MTN Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Dealers may from time to time purchase and sell MTN Debentures in the secondary market but are not obligated to do so. No assurance can be given that there will be a secondary market for the MTN Debentures. See "Risk Factors". The offering price and other selling terms for such sales in the secondary market may, from time to time, be varied by such Dealers.

The Corporation has agreed to indemnify the Dealers and their directors, officers, employees, shareholders and agents against liabilities arising out of, among other things, any misrepresentation in this short form prospectus and the documents incorporated by reference herein, other than, among other things, liabilities arising out of any misrepresentations made by the Dealers or relating solely to the Dealers where the Dealers had an opportunity of reviewing the same.

The Corporation and, if applicable, the Dealers, reserve the right to reject any offer to purchase MTN Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify an offering of MTN Debentures under this short form prospectus without notice.

## ELIGIBILITY FOR INVESTMENT

In the opinion of Farris, Vaughan, Wills & Murphy LLP, counsel to the Corporation, and Lawson Lundell LLP, counsel to the Dealers, based on the provisions of the *Income Tax Act* (Canada) and the regulations thereunder (collectively, the "Tax Act") in effect on the date hereof, the MTN Debentures would, if issued on the date hereof, be qualified investments under the Act for trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans, registered disability savings plans, deferred profit sharing plans (other than a trust governed by a deferred profit sharing plan for which any employer is the Corporation or an employer that does not deal at arm's length with the Corporation within the meaning of the Act) and tax-free savings accounts. Notwithstanding the foregoing, if the MTN Debentures are "prohibited investments" for the purposes of a tax-free savings account, a holder will be subject to a penalty tax as set out in the Tax Act. Holders are advised to consult their own tax advisors in this regard.

## RISK FACTORS

An investment in the MTN Debentures involves certain risks. Before investing, prospective purchasers of MTN Debentures should carefully consider, in light of their own financial circumstances, the factors set out below, the risks described under "Business Risk Management" in the Corporation's annual and interim management discussion and analysis that are incorporated by reference herein, any other risks identified in an applicable pricing supplement or other prospectus supplement, as well as the other information contained or incorporated by reference in this short form prospectus.

### Credit Risk and Prior Ranking Indebtedness

The likelihood that purchasers of the MTN Debentures will receive payments owing to them under the terms of the MTN Debentures will depend on the financial health of the Corporation and its creditworthiness. In addition, the MTN Debentures are unsecured obligations of the Corporation. Therefore, if the Corporation becomes bankrupt, liquidates its assets, reorganizes or enters into certain other transactions, the Corporation's assets will be available to pay its obligations with respect to the MTN Debentures only after it has paid all of its secured indebtedness in full. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the MTN Debentures then outstanding.

### Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the MTN Debentures are not a recommendation to purchase, hold or sell the MTN Debentures, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time or that these ratings will not be revised or withdrawn entirely in the future by the relevant rating agency. Real or anticipated changes in credit ratings for the MTN Debentures may affect the market value of the MTN Debentures. In addition, real or anticipated changes in credit ratings can affect the cost of or terms on which FortisBC can issue MTN Debentures or incur other debt.

### Market Value Fluctuation

Prevailing interest rates may affect the market value of any fixed interest rate MTN Debentures. Assuming all other factors remain unchanged, the market value of any fixed interest rate MTN Debentures will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline.

### Lack of Public Markets for the MTN Debentures

Each offering of MTN Debentures will be a new issue of debt securities for which there is no existing trading market. The Corporation does not intend to list the MTN Debentures on any securities exchange or to arrange for any quotation system to quote them, and consequently the Corporation will not be subject to regulation by any securities exchange or quotation system. There can be no assurance as to the liquidity of any trading market for the MTN Debentures or that a trading market for any of the MTN Debentures will develop. Even if a trading market in the MTN Debentures develops, the MTN Debentures could trade at prices that may be higher or lower than their initial offering prices and there may be limited transparency of trading prices. The market price for the MTN Debentures may be affected by prevailing interest rates, FortisBC's results of operations and financial position, the ratings assigned to the MTN Debentures or other indebtedness of FortisBC, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Corporation.

## RELATIONSHIP BETWEEN FORTISBC AND CERTAIN DEALERS

Each of CIBC World Markets Inc., HSBC Securities (Canada) Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and Scotia Capital Inc. is an affiliate of a Canadian chartered bank (the "Bank Affiliates") which has extended credit facilities (the "Credit Facilities") to the Corporation upon which the Corporation may draw from time to time. Consequently, the Corporation may be considered a "connected issuer" of each of these Dealers within the meaning of applicable Canadian securities legislation. The Corporation is currently in compliance with the terms of the agreements governing the Credit Facilities and none of the Bank Affiliates has waived a breach by the Corporation of these agreements since their execution. The financial position of the Corporation has not changed substantially and adversely since the indebtedness under the Credit Facilities was incurred. The Credit Facilities are unsecured.

All or a portion of the net proceeds received pursuant to this offering may be used to reduce the Corporation's indebtedness to its lenders, including the Bank Affiliates. See "Use of Proceeds". The decision to offer the MTN Debentures offered hereunder and the determination of the terms of any distribution of MTN Debentures will be made through negotiations between the Corporation and the Dealers. The Bank Affiliates will not have any involvement in such decision or determination, but will be advised of each such issuance and the terms thereof. Each Dealer will receive its share of the Dealers' fee payable by the Corporation to the Dealers in respect of any issue of MTN Debentures in accordance with that Dealer's participation in such issue.

## LEGAL MATTERS

Certain legal matters relating to the offering will be passed upon on behalf of the Corporation by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Dealers by Lawson Lundell LLP. At the date hereof, partners and associates of each of Farris, Vaughan, Wills & Murphy LLP and Lawson Lundell LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any affiliate of the Corporation.

## AUDITORS AND TRUSTEE

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 700 West Georgia Street, P.O. Box 10101, Vancouver, British Columbia, V7Y 1C7.

Computershare Trust Company of Canada, at its office located at 510 Burrard Street, Vancouver, British Columbia V6C 3B9, is the Trustee under the Indenture. Registers for the registration and transfer of the MTN Debentures will be kept at the offices of the Trustee in Vancouver, British Columbia.

## PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

## AUDITORS' CONSENT

We have read the short form base shelf prospectus of FortisBC Inc. (the "Corporation") dated May 22, 2009 relating to the sale and issue of Medium Term Note Debentures of the Corporation in an aggregate principal amount not to exceed $300,000,000. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned prospectus of our report to the shareholder of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2008 and 2007, and the consolidated statements of earnings, retained earnings and cash flows for each year in the two-year period ended December 31, 2008. Our report is dated January 30, 2009.

(Signed) Ernst & Young LLP
Chartered Accountants

Vancouver, Canada
May 22, 2009

**CERTIFICATE OF FORTISBC INC.**

Dated: May 22, 2009

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada.

| | |
|---|---|
| (signed) John C. Walker<br>President and Chief Executive Officer | (signed) Michele I. Leeners<br>Vice President, Finance and Chief Financial Officer |

On behalf of the Board of Directors

| | |
|---|---|
| (signed) Randall L. Jespersen<br>Director | (signed) R. Harry McWatters<br>Director |

## CERTIFICATE OF THE DEALERS

Dated: May 22, 2009

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada.

CIBC World Markets Inc.

(Signed) By: “Cliff Inskip”

HSBC Securities (Canada) Inc.

(Signed) By: “Rod A. McIsaac”

National Bank Financial Inc.

(Signed) By: “Paul Prendergast”

RBC Dominion Securities Inc.

(Signed) By: “Robert M. Brown”

Scotia Capital Inc.

(Signed) By: “D. Gregory Lawrence”

*No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This pricing supplement, together with the short from base shelf prospectus of FortisBC Inc. (the "Corporation") dated May 22, 2009, as amended or supplemented, and each document incorporated by reference into such short form base shelf prospectus, (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws, and, subject to certain exceptions, will not be offered or sold within the United States or to or for the account or benefit of U.S. Persons.*

**Pricing Supplement No. 1 dated May 28, 2009**
**(To a Short Form Base Shelf Prospectus dated May 22, 2009)**

FORTISBC

**FORTISBC INC.**
**MEDIUM TERM NOTE DEBENTURES, SERIES 1**
**(UNSECURED)**

| | |
|---|---|
| Amount and Currency of Issue: | C$105,000,000 |
| Issue and Delivery Date: | June 2, 2009 |
| Issue Price: | $100 per $100 principal amount |
| Commission: | 0.50% |
| Net Proceeds to the Corporation: | C$104,475,000 |
| Maturity Date: | June 2, 2039 |
| Type of Security: | Global Debenture |
| Interest Rate: | 6.10% per annum, payable semi-annually in arrears |
| Offering Yield: | 6.10% |
| Interest Payment Date(s): | June 2 and December 2 |
| Initial Interest Payment Date: | December 2, 2009 |
| Initial Interest Payment Amount: | $3.05 per $100 principal amount |
| Redemption Provisions: | The Medium Term Note Debentures, Series 1 issued hereunder will be redeemable, at the Corporation's option, in whole at any time or in part from time to time on not more than 60 and not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. |
| CUSIP Number: | 34958ZAA1 |
| ISIN Number: | CA 34958ZAA18 |
| Depository: | CDS Clearing and Depository Services Inc. |
| Trustee/Registrar/Paying Agent: | Computershare Trust Company of Canada |
| Selling Agent(s): | Scotia Capital Inc.<br>CIBC World Markets Inc.<br>HSBC Securities (Canada) Inc.<br>National Bank Financial Inc.<br>RBC Dominion Securities Inc. |

## DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which may not be specifically listed in the Prospectus or any amendment or supplement delivered herewith) which have been filed by the Corporation with the various securities commissions or similar authorities in each of the provinces of Canada are specifically incorporated by reference into the Prospectus, as amended or supplemented, and provide disclosure pertaining to the Medium Term Note Debentures, Series 1:

(a) audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2008 and 2007, together with the notes thereto and the auditors' reports thereon;

(b) management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2008;

(c) unaudited consolidated interim financial statements of the Corporation as at and for the three months ended March 31, 2009, together with the notes thereto;

(d) management's discussion and analysis of financial condition and results of operations of the Corporation for the three months ended March 31, 2009; and

(e) annual information form of the Corporation dated February 25, 2009.

## USE OF PROCEEDS

The net proceeds will be used for general corporate purposes, including repayment of existing indebtedness and financing the Corporation's capital expenditure program and working capital requirements.

## DEFINITIONS

"*Canada Yield Price*" means the price in respect of the principal amount of the Medium Term Note Debentures, Series 1 to be redeemed, calculated as of the Business Day immediately prior to the Business Day on which the Corporation gives a Notice of Redemption in respect of such Medium Term Note Debentures, Series 1, equal to the net present value of all scheduled payments of interest and principal on the Medium Term Note Debentures, Series 1 to be redeemed from the Redemption Date to the Maturity Date using as a discount rate the sum of the Canada Yield on such Business Day plus 0.49%.

"*Canada Yield*" means, on any date, the yield to maturity on such date as determined by the arithmetic average (rounded to four decimal places) of the yields quoted at 10:00 a.m. (Vancouver time) by two major Canadian investment dealers selected by the Corporation, assuming semi-annual compounding and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity approximately equal to the remaining term to maturity of the Medium Term Note Debentures, Series 1.

Capitalized terms used, but not defined herein, have the meanings given thereto in the trust indenture dated May 27, 2009 between the Corporation and Computershare Trust Company of Canada, as supplemented or amended.

*No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This pricing supplement, together with the short from base shelf prospectus of FortisBC Inc. (the "Corporation") dated May 22, 2009, as amended or supplemented, and each document incorporated by reference into such short form base shelf prospectus, (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws, and, subject to certain exceptions, will not be offered or sold within the United States or to or for the account or benefit of U.S. Persons.*

**Pricing Supplement No. 2 dated November 19, 2010**
**(To a Short Form Base Shelf Prospectus dated May 22, 2009)**

FORTISBC

**FORTISBC INC.**
**MEDIUM TERM NOTE DEBENTURES, SERIES 2**
**(UNSECURED)**

| | |
|---|---|
| Amount and Currency of Issue: | C$100,000,000 |
| Issue and Delivery Date: | November 24, 2010 |
| Issue Price: | $99.828 per $100 principal amount |
| Commission: | 0.50% |
| Net Proceeds to the Corporation: | C$99,328,000 |
| Maturity Date: | November 24, 2050 |
| Type of Security: | Global Debenture |
| Interest Rate: | 5.00% per annum, payable semi-annually in arrears |
| Offering Yield: | 5.01% |
| Interest Payment Date(s): | November 24 and May 24 |
| Initial Interest Payment Date: | May 24, 2011 |
| Initial Interest Payment Amount: | $2.50 per $100 principal amount |
| Redemption Provisions: | The Medium Term Note Debentures, Series 2 issued hereunder will be redeemable, at the Corporation's option, in whole at any time or in part from time to time on not more than 60 and not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. |
| Credit Ratings: | The Medium Term Note Debentures, Series 2 will rank *pari passu* with the Medium Term Note Debentures, Series 1 issued by the Company on June 2, 2009. The Medium Term Note Debentures, Series 1 are currently rated Baa1, Stable Outlook by Moody's Investors Service and A(low) Stable Trend by DBRS. |
| CUSIP Number: | 34958ZAB9 |
| ISIN Number: | CA 34958ZAB90 |
| Depository: | CDS Clearing and Depository Services Inc. |
| Trustee/Registrar/Paying Agent: | Computershare Trust Company of Canada |
| Selling Agent(s): | RBC Dominion Securities Inc.<br>CIBC World Markets Inc.<br>Scotia Capital Inc.<br>HSBC Securities (Canada) Inc.<br>National Bank Financial Inc.<br>BMO Nesbitt Burns Inc.<br>TD Securities Inc. |

## DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which may not be specifically listed in the Prospectus or any amendment or supplement delivered herewith) which have been filed by the Corporation with the various securities commissions or similar authorities in each of the provinces of Canada are specifically incorporated by reference into the Prospectus, as amended or supplemented, and provide disclosure pertaining to the Medium Term Note Debentures, Series 2:

(a) audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2009 and 2008, together with the notes thereto and the auditors' reports thereon;

(b) management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2009;

(c) unaudited consolidated interim financial statements of the Corporation as at and for the three and nine months ended September 30, 2010, together with the notes thereto;

(d) management's discussion and analysis of financial condition and results of operations of the Corporation for the three and nine months ended September 30, 2010; and

(e) annual information form of the Corporation dated February 24, 2010.

## USE OF PROCEEDS

The net proceeds will be used for general corporate purposes, including repayment of existing indebtedness and financing the Corporation's capital expenditure program and working capital requirements.

## DEFINITIONS

"*Canada Yield Price*" means the price in respect of the principal amount of the Medium Term Note Debentures, Series 2 to be redeemed, calculated as of the Business Day immediately prior to the Business Day on which the Corporation gives a Notice of Redemption in respect of such Medium Term Note Debentures, Series 2, equal to the net present value of all scheduled payments of interest and principal on the Medium Term Note Debentures, Series 2 to be redeemed from the Redemption Date to the Maturity Date using as a discount rate the sum of the Canada Yield on such Business Day plus 0.335%.

"*Canada Yield*" means, on any date, the yield to maturity on such date as determined by the arithmetic average (rounded to four decimal places) of the yields quoted at 10:00 a.m. (Vancouver time) by two major Canadian investment dealers selected by the Corporation, assuming semi-annual compounding and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity approximately equal to the remaining term to maturity of the Medium Term Note Debentures, Series 2.

Capitalized terms used, but not defined herein, have the meanings given thereto in the trust indenture dated May 27, 2009 between the Corporation and Computershare Trust Company of Canada, as supplemented or amended.

5. **Full listing of each bond issue applicable for the 2012 Test Year including any future anticipated issues with full details (e.g. principal face value, nominal interest rate, effective rate if issued at discount or premium, relevant benchmark Government of Canada bond, credit spread benchmark, date of issue, date of maturity, length of maturity, etc.**

    - See attached for FBC's bond issues for 2012 Test Year

**FBC**
**Long-term Debt**
**29-Jun-2012**

| | Coupon | Maturity | Life | Yield to MATURITY Per FBC | Yield to Maturity Per RBC | 29-Jun-12 Market Price (a) ($CAD) | 29-Jun-12 Carrying Value ($CAD 000s) | 29-Jun-12 Market Price (% of Par) | 29-Jun-12 Market Value ($CAD 000s) | 29-Jun-12 Current GOC BM Per RBC | 29-Jun-12 Current Spread to BM bps | New Issue GOC BM | New Issue Spread to BM bps |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FBC Inc. | | | | | | | | | | | | | |
| Series F* | 9.65% | 16-Oct-12 | 0.30 | 2.121% | 1.704% | 102.216 | 15,000 | 102.216% | 15,332 | CAN 2 1SEP12 | 75 | Not Available | 144 |
| Series G* | 8.80% | 28-Aug-23 | 11.17 | 3.323% | 3.317% | 150.738 | 25,000 | 150.738% | 37,685 | CAN 8 1JUN23 | 150 | Not Available | 133 |
| Series H* | 8.77% | 1-Feb-16 | 3.59 | 2.398% | 2.372% | 121.799 | 25,000 | 121.799% | 30,450 | CAN 3 1DEC15 | 120 | Not Available | 69 |
| Series I* | 7.81% | 1-Dec-21 | 9.43 | 3.042% | 3.036% | 138.803 | 25,000 | 138.803% | 34,701 | CAN 3.25 1JUN21 | 140 | Not Available | 63 |
| Series 01-1 Public | 5.48% | 28-Nov-14 | 2.42 | 1.850% | 1.828% | 108.525 | 140,000 | 108.525% | 151,935 | CAN 2.25 1AUG14 | 80 | CAN 5 1JUN14 | 97 |
| MTN | 5.60% | 9-Nov-35 | 23.38 | 3.964% | 3.963% | 124.771 | 100,000 | 124.771% | 124,771 | CAN 4 1JUN41 | 163 | CAN 5.75 1JUN29 | 120 |
| MTN | 6.10% | 2-Jun-39 | 26.94 | 3.964% | 3.963% | 135.157 | 105,000 | 135.157% | 141,915 | CAN 4 1JUN41 | 163 | CAN 5.75 1JUN29 | 125 |
| MTN | 5.90% | 4-Jul-47 | 35.04 | 3.964% | 3.963% | 136.493 | 105,000 | 136.493% | 143,318 | CAN 4 1JUN41 | 163 | CAN 5 1JUN37 | 195 |
| MTN | 5.00% | 24-Nov-50 | 38.43 | 3.963% | 3.963% | 120.355 | 100,000 | 120.355% | 120,355 | CAN 4 1JUN41 | 163 | CAN 5 1JUN37 | 135 |
| Total FBC | | | | | | | **640,000** | | **800,461** | | | | |

SOURCE: RBC Capital Markets, Company documents

* - Due to the nature of these debt issues as secured private placements and the fact that they occurred back in 1990s, there is no pricing supplements or terms sheet information available to indicate whether these debt instruments were issued at a premium/discount or the underlying GofC benchmark bond and spread at the time of issuance. This lack of available details was corroborated through a review of the closing books as well inquiring to the Corporation's external counsel. An estimated credit spread has been derived as the difference between the Average monthly Benchmark Government of Canada Bond yields - Long-term during the month of issuance (Prepared by the Bank of Canada)and the Coupon.

6. **All Prospectuses of Equity Offerings of the utility and/or its corporate parent within the last six years, if applicable:**

   - FBC is a wholly-owned privately entity and only issues equity to its parent, Fortis Pacific Holdings Inc.
   - FBC is indirectly and wholly-owned by its ultimate parent, Fortis Inc. (FTS - a TSX listed company)
   - See section 6 of FEI's Company Related Documents for FTS equity offerings by way of Prospectuses.

   a. **Details of any new equity issues from the financial market for the utility and/or corporate parent, if applicable:**

**7. Latest annual filing to the Commission of Operational and Financial Results.**

- See attached documents for FBC's latest annual filing

Dennis Swanson
Director, Regulatory Affairs

**FortisBC Inc.**
Suite 100 - 1975 Springfield Road
Kelowna, BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
electricity.regulatory.affairs@fortisbc.com
www.fortisbc.com

April 30, 2012

**Via Email**
**Via Mail**

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

***Re: FortisBC Inc. - Annual Report to BC Utilities Commission***

Please find enclosed twelve copies of FortisBC's Annual Report to the BC Utilities Commission to December 31, 2011.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

# ELECTRIC UTILITIES

# ANNUAL REPORT

# FORTISBC INC.

Suite 100, 1975 Springfield Road
Kelowna, British Columbia
V1Y 7V7

TO THE

**BRITISH COLUMBIA UTILITIES COMMISSION**

For the Period January 1, 2011 to December 31, 2011

# TABLE OF CONTENTS

**SCHEDULE 1 - UTILITY RATE BASE** .......... **2**

UTILITY PLANT IN SERVICE .......... 3
CAPITAL VARIANCE ANALYSIS .......... 4
UTILITY PLANT UNDER CONSTRUCTION .......... 7
ANALYSIS OF DEFERRED CHARGES AND CREDITS .......... 10
ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION .......... 12
ALLOWANCE FOR WORKING CAPITAL .......... 13
ADJUSTMENT FOR CAPITAL ADDITIONS .......... 14
BALANCE SHEET – ASSETS .......... 15
BALANCE SHEET – LIABILITIES .......... 16

**SCHEDULE 2 – EARNED RETURN** .......... **17**

WEATHER NORMALIZATION .......... 18
ELECTRIC OPERATING REVENUES BY RATE CLASS .......... 18
ANALYSIS OF POWER PURCHASES AND GENERATION OF POWER .......... 19
ANALYSIS OF WHEELING EXPENSE .......... 19
ELECTRIC OPERATING AND MAINTENANCE EXPENSE .......... 20
SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT .......... 22

**SCHEDULE 3 – INCOME TAX EXPENSE** .......... **24**

**SCHEDULE 4 – COMMON EQUITY** .......... **25**

**SCHEDULE 5 – RETURN ON CAPITAL** .......... **26**

**EXECUTIVE SUMMARY** .......... **27**

**DIRECTORS, OFFICERS AND SHAREHOLDERS** .......... 27
IMPORTANT CHANGES IN THE YEAR .......... 29
*A. OPERATING* .......... *29*
*B. CUSTOMER SERVICE* .......... *29*
*C. ENERGY MANAGEMENT* .......... *30*
*D. REGULATORY* .......... *31*
*E. AUDIT* .......... *31*
*F. LEGAL PROCEEDINGS* .......... *32*
COMPANY PROFILE .......... 33
TEN-YEAR SUMMARY .......... 34
DECLARATIONS .......... 35

**APPENDIX A** .......... **37**

RECONCILIATION OF FINANCIAL STATEMENTS .......... 37

**APPENDIX B** .......... **41**

## SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2011

| Line | Account | | Reference | Actual 2010 | Decision 2011 | Actual 2011 | Change from Decision |
|---|---|---|---|---|---|---|---|
| | | | | ($000s) | | | |
| 1 | 101 | Plant in Service, January 1 | **p. 3** | 1,273,476 | 1,417,415 | 1,403,617 | (13,798) |
| 2 | | Net Additions | **p. 6** | 130,141 | 147,367 | 128,214 | (19,153) |
| 3 | | Plant in Service, December 31 | | 1,403,617 | 1,564,782 | 1,531,831 | (32,951) |
| 4 | | | | | | | |
| 5 | | **Add:** | | | | | |
| 6 | 107 | CWIP not subject to AFUDC | **p. 7** | 7,213 | 5,444 | 7,488 | 2,044 |
| 7 | 114 | Plant Acquisition Adjustment | | 11,912 | 11,912 | 11,912 | - |
| 8 | 186 | Deferred and Preliminary Charges | **p. 11** | 16,698 | 24,984 | 13,157 | (11,827) |
| 9 | | | | | | | |
| 10 | | | | 1,439,440 | 1,607,122 | 1,564,387 | (42,735) |
| 11 | | **Less:** | | | | | |
| 12 | | Accumulated Depreciation | | | | | |
| 13 | | and Amortization | **p. 12** | 323,203 | 375,482 | 357,692 | (17,790) |
| 14 | 252 | Contributions in Aid of Construction | | 93,763 | 100,504 | 95,551 | (4,952) |
| 15 | | | | 416,967 | 475,986 | 453,243 | (22,742) |
| 16 | | | | | | | |
| 17 | | Depreciated Rate Base | | 1,022,473 | 1,131,136 | 1,111,144 | (19,992) |
| 18 | | | | | | | |
| 19 | | Prior Year Depreciated Utility Rate Base | | 915,158 | 1,024,361 | 1,022,473 | (1,888) |
| 20 | | | | | | | |
| 21 | | Mean Depreciated Utility Rate Base | | 968,815 | 1,077,748 | 1,066,808 | (10,940) |
| 22 | | | | | | | |
| 23 | | **Add:** | | | | | |
| 24 | | Allowance for Working Capital | **p. 13** | 5,756 | 5,599 | 4,954 | (645) |
| 25 | | Adjustment for Capital Additions | **p. 14** | (28,934) | 9,894 | (5,870) | (15,764) |
| 26 | | | | | | | |
| 27 | | Mid-Year Utility Rate Base | | 945,637 | 1,093,241 | 1,065,892 | (27,349) |

# UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2011

| Line | Account | | December 31 2010 | Additions | Retirements & Reclass | December 31 2011 |
|---|---|---|---|---|---|---|
| | | **Hydraulic Production Plant** | | ($000s) | | |
| 1 | 330 | Land Rights | 962 | - | - | 962 |
| 2 | 331 | Structures and Improvements | 12,609 | 184 | - | 12,793 |
| 3 | 332 | Reservoirs, Dams & Waterways | 26,644 | 705 | - | 27,349 |
| 4 | 333 | Water Wheels, Turbines and Gen. | 73,448 | 20,665 | - | 94,113 |
| 5 | 334 | Accessory Equipment | 32,934 | 6,649 | (593) | 38,990 |
| 6 | 335 | Other Power Plant Equipment | 41,642 | 255 | - | 41,897 |
| 7 | 336 | Roads, Railroads and Bridges | 1,287 | - | - | 1,287 |
| 8 | | | 189,525 | 28,458 | (593) | 217,390 |
| 9 | | **Transmission Plant** | | | | |
| 10 | 350 | Land Rights | 7,271 | 40 | - | 7,311 |
| 11 | 350.1 | Land Rights - Clearing | 6,236 | 40 | - | 6,276 |
| 12 | 353 | Station Equipment | 150,925 | 32,617 | (2,068) | 181,474 |
| 13 | 355 | Poles Towers & Fixtures | 89,033 | 2,845 | (80) | 91,799 |
| 14 | 356 | Conductors and Devices | 86,903 | 2,798 | (80) | 89,621 |
| 15 | 359 | Roads and Trails | 1,121 | - | - | 1,121 |
| 16 | | | 341,489 | 38,342 | (2,228) | 377,603 |
| 17 | | **Distribution Plant** | | | | |
| 18 | 360 | Land Rights | 2,689 | 200 | - | 2,889 |
| 19 | 360.1 | Land Rights - Clearing | 9,964 | 53 | - | 10,017 |
| 20 | 362 | Station Equipment | 199,086 | 26,346 | (1,633) | 223,800 |
| 21 | 364 | Poles Towers & Fixtures | 137,498 | 7,924 | (183) | 145,239 |
| 22 | 365 | Conductors and Devices | 224,957 | 12,265 | (300) | 236,922 |
| 23 | 368 | Line Transformers | 104,732 | 6,792 | (729) | 110,795 |
| 24 | 369 | Services | 7,292 | - | - | 7,292 |
| 25 | 370 | Meters | 13,593 | 809 | (300) | 14,102 |
| 26 | 371 | Installation on Customers' Premises | 938 | - | - | 938 |
| 27 | 373 | Street Lighting and Signal System | 11,485 | 747 | (23) | 12,208 |
| 28 | | | 712,234 | 55,136 | (3,168) | 764,202 |
| 29 | | **General Plant** | | | | |
| 30 | 389 | Land | 12,093 | 63 | - | 12,157 |
| 31 | 390 | Structures-Frame & Iron | 337 | - | - | 337 |
| 32 | 390.1 | Structures-Masonry | 27,045 | 1,345 | - | 28,390 |
| 33 | 391 | Office Furniture & Equipment | 5,729 | 173 | - | 5,902 |
| 34 | 391.1 | Computer Equipment | 62,875 | 6,452 | (193) | 69,134 |
| 35 | 392 | Transportation Equipment | 17,755 | 3,509 | (264) | 21,000 |
| 36 | 394 | Tools and Work Equipment | 11,296 | 492 | (4) | 11,784 |
| 37 | 397 | Communication Structures and Equipment | 23,238 | 694 | - | 23,932 |
| 38 | | | 160,368 | 12,728 | (461) | 172,635 |
| 39 | | | | | | |
| 40 | 101 | **Plant in Service** | 1,403,617 | 134,663 | (6,450) | 1,531,831 |
| 41 | 107.1 | Plant under construction not subject | | | | |
| 42 | | to AFUDC | 7,213 | | | 7,488 |
| 43 | 107.2 | Plant under construction | | | | |
| 44 | | subject to AFUDC | 50,769 | | | 4,197 |
| 45 | 114 | Utility Plant Acquisition Adjustment | 11,912 | | | 11,912 |
| 46 | 105 | Utility Plant per Balance Sheet | 1,473,511 | | | 1,555,427 |

*Note: Minor differences due to rounding.*

# CAPITAL VARIANCE ANALYSIS

| Line | REGULATED CAPITAL PROJECTS | Actual Expenditure | Budget (1) | Difference over/(under) | COMMENTS |
|---|---|---|---|---|---|
| **1** | **Hydraulic Production:** | | ($000s) | | |
| 2 | 2011 Provincial Sales Tax (PST) Refund | (145) | - | (145) | Unbudgeted Provincial Sales Tax refund |
| 3 | South Slocan Plant Automation | 208 | 251 | (43) | Work carried forward to 2012 due to delay in commissioning |
| 4 | South Slocan Fire Panel | 269 | 275 | (6) | Work carried forward to 2012 due to delay in commissioning |
| 5 | Upper Bonnington Spillgate Rebuild / Upgrade | 40 | 630 | (590) | Work carried forward to 2012 due to change in project schedule |
| 6 | Lower Bonnington Power House Windows | 244 | 362 | (118) | Work carried forward to 2012 |
| 7 | All Plants Minor Sustainment | 469 | 633 | (164) | Savings achieved primarily due to job scope adjustments |
| 8 | Lower & Upper Bonnington Communication Network | 48 | - | 48 | Carryover work from 2010 due to workload |
| 9 | South Slocan Unit 1 Life Extension | 44 | 42 | 2 | Reasonable budgetary variation |
| 10 | All Plants Station Service | 927 | 1,352 | (426) | Work carried forward to 2012 due to delay in equipment procurement & delivery |
| 11 | South Slocan Head Gate Hoist, Control, Wire Rope Upgrade/Replacement | 37 | - | 37 | Emergency unbudgeted safety related project |
| 12 | Corra Linn Unit 1 Life Extension | 2,990 | 2,507 | 483 | Carryover work from 2010 due to delay in turbine delivery |
| 13 | Corra Linn Unit 2 Life Extension | 12,090 | 12,781 | (691) | Savings primarily achieved in equipment cost |
| 14 | Upper Bonnington Extension Trash Rack Gantry Replacement | 165 | - | 165 | Carryover from 2010 due to delay in equipment delivery |
| 15 | South Slocan Domestic Water Supply Ph.3 | 61 | - | 61 | Carryover from 2010, due to delay in obtaining Water Permit |
| 16 | Lower & Upper Bonnington Plant Totalizer Upgrade | 93 | 89 | 4 | Advanced procurement of materials from 2012 to 2011 |
| 17 | Queen's Bay Level Gauge Building Ph.1 | 3 | - | 3 | Carryover work from 2009 due to land access difficulties |
| 18 | **Subtotal Hydraulic Production** | **17,543** | **18,924** | **(1,381)** | |

(1) *Order G-195-10*

*Note: Minor differences due to rounding.*

## **CAPITAL VARIANCE ANALYSIS,** cont'd

| Line | REGULATED CAPITAL PROJECTS | Actual Expenditure | Budget [1] | Difference over/(under) | COMMENTS |
|---|---|---|---|---|---|
| **19** | **Transmission Plant:** | | ($000s) | | |
| 20 | Ellison to Sexsmith Transmission Tie | 638 | 693 | (55) | Work carried forward to 2012 |
| 21 | Okanagan Transmission Reinforcement | 12,821 | 16,056 | (3,235) | Work carried forward for the BC Hydro 500kV Upgrade to 2012 |
| 22 | Benvoulin Distribution Source | 993 | - | 993 | Carryover work from 2010. Total project within budgetary limits |
| 23 | Huth Bus Reconfiguration | 3,612 | 4,860 | (1,247) | Work carried forward to 2012 due to shift in fibre completion |
| 24 | Capitalized Inventory | 727 | - | 727 | Changes in inventory levels due to project timing |
| 25 | Recreation Capacity Increase Stages 1, 2, 3 | (21) | - | (21) | Carryover from 2010 |
| 26 | 30 Line Conversion Slocan & Coffee Creek Substations | 314 | - | 314 | Carryover work from 2009 |
| 27 | Transmission Sustainment | 2,477 | 2,455 | 22 | Reasonable budgetary variation |
| 28 | Station Sustainment | 5,223 | 2,764 | 2,459 | Carryover work from 2010 (Passmore 19L Breaker & Bulk Oil Replacement projects) |
| **29** | **Subtotal Transmission Plant** | **26,786** | **26,828** | **(42)** | |

*[1] Order G-195-10*

*Note: Minor differences due to rounding.*

## **CAPITAL VARIANCE ANALYSIS,** cont'd

| Line | REGULATED CAPITAL PROJECTS | Actual Expenditure | Budget [(1)] | Difference over/(under) | COMMENTS |
|---|---|---|---|---|---|
| **30** | **Distribution Plant:** | | ($000s) | | |
| 31 | New Connects System Wide | 16,409 | 21,584 | (5,176) | Reduced customer activity |
| 32 | Distribution Unplanned Growth Projects | 981 | 986 | (5) | Reasonable budgetary variation |
| 33 | Small Growth Projects | 685 | 751 | (66) | Reasonable budgetary variation |
| 34 | Distribution Sustainment | 8,359 | 8,227 | 132 | Reasonable budgetary variation |
| **35** | **Subtotal Distribution Plant** | **26,434** | **31,549** | **(5,115)** | |
| **36** | **General Plant:** | | | | |
| 37 | Distribution Station Automation | 2,162 | 1,602 | 560 | Variance due to shifting completion of three 2010 substations into 2011 |
| 38 | Communications Upgrades | 1,975 | 1,613 | 362 | Primarily due to the unbudgeted (customer driven) Celgar Interconnection facility upgrade |
| 39 | Mandatory Reliability Standards Compliance | 872 | 615 | 257 | Variance due to unforeseen complexities in project implementation |
| 40 | Vehicles | 2,664 | 2,072 | 592 | Spending carried forward from 2010 due to delayed delivery of vehicles |
| 41 | Metering | 316 | 221 | 95 | Primarily due to procurement of meter inventory |
| 42 | Information Systems | 4,829 | 4,682 | 146 | Essential expenditures in infrastructure sustainment and application enhancements |
| 43 | Telecommunications | 315 | 371 | (56) | Work carried forward to 2012 primarily due to delay in material delivery |
| 44 | Buildings | 1,287 | 1,288 | (1) | Reasonable budgetary variation |
| 45 | Kootenay Long Term Facility Strategy | 433 | 503 | (70) | Project scope still under development |
| 46 | Okanagan Long Term Solution | 190 | 507 | (317) | Project scope still under development |
| 47 | PCB Environmental Compliance | 1,718 | 1,926 | (208) | Work carried forward from 2011 to 2012 |
| 48 | Furniture & Fixtures | 230 | 182 | 48 | Carryover from unfinished project in 2010 completed in early 2011 |
| 49 | Tools & Equipment | 609 | 623 | (14) | Reasonable budgetary variation |
| **50** | **Subtotal General Plant** | **17,602** | **16,206** | **1,396** | |
| 51 | | | | | |
| **52** | **Total Gross Expenditure** | **88,365** | **93,507** | **(5,142)** | |
| 53 | Change to Work in Progress | 46,298 | | | |
| 54 | Plant Retirements | (6,450) | | | |
| **55** | **Net Additions to Plant** | **128,214** | | | |

*[(1)] Order G-195-10*

*Note: Minor differences due to rounding.*

# UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2011

| | | CWIP Dec. 31, 2010 | Actual Expenditures | CWIP Dec. 31, 2011 | Additions to Plant in Service |
|---|---|---|---|---|---|
| | | | ($000s) | | |
| 1 | **Hydraulic Production** | | | | |
| 2 | 2011 Provincial Sales Tax (PST) Refund | - | (145) | - | (145) |
| 3 | South Slocan Plant Automation | - | 208 | 208 | - |
| 4 | South Slocan Fire Panel | - | 269 | 269 | - |
| 5 | Upper Bonnington Spillgate Rebuild / Upgrade | 3 | 40 | 43 | - |
| 6 | Lower Bonnington Power House Windows | 8 | 244 | 252 | - |
| 7 | All Plants Minor Sustainment | - | 469 | 239 | 231 |
| 8 | Lower & Upper Bonnington Communication Network | 343 | 48 | - | 390 |
| 9 | South Slocan Unit 1 Life Extension | - | 44 | - | 44 |
| 10 | All Plants Station Service | 78 | 927 | 834 | 171 |
| 11 | South Slocan Head Gate Hoist, Control, Wire Rope Upgrade/Replacement | - | 37 | - | 37 |
| 12 | Corra Linn Unit 1 Life Extension | 13,010 | 2,990 | - | 16,000 |
| 13 | Corra Linn Unit 2 Life Extension | 3,265 | 12,090 | 497 | 14,859 |
| 14 | Upper Bonnington Extension Trash Rack Gantry Replacement | 204 | 165 | - | 369 |
| 15 | South Slocan Domestic Water Supply Ph.3 | 86 | 61 | - | 147 |
| 16 | Lower & Upper Bonnington Plant Totalizer Upgrade | - | 93 | 49 | 44 |
| 17 | Queen's Bay Level Gauge Building Ph.1 | 18 | 3 | 21 | - |
| 18 | | **17,015** | **17,543** | **2,411** | **32,147** |
| 19 | **Transmission Plant** | | | | |
| 20 | Ellison to Sexsmith Transmission Tie | - | 638 | 638 | - |
| 21 | Okanagan Transmission Reinforcement | 32,744 | 12,821 | 506 | 45,060 |
| 22 | Benvoulin Distribution Source | - | 993 | - | 993 |
| 23 | Huth Bus Reconfiguration | 241 | 3,612 | - | 3,853 |
| 24 | Capitalized Inventory | 5,333 | 727 | 6,060 | - |
| 25 | Recreation Capacity Increase Stages 1,2,3 | - | (21) | - | (21) |
| 26 | 30 Line Conversion Slocan & Coffee Creek Substations | - | 314 | - | 314 |
| 27 | Transmission Sustainment | 84 | 2,477 | - | 2,561 |
| 28 | Station Sustainment | 563 | 5,223 | 370 | 5,416 |
| 29 | | **38,965** | **26,786** | **7,574** | **58,177** |
| 30 | **Distribution Plant** | | | | |
| 31 | New Connects System Wide | - | 16,409 | - | 16,409 |
| 32 | Distribution Unplanned Growth Projects | - | 981 | - | 981 |
| 33 | Small Growth Projects | - | 685 | - | 685 |
| 34 | Distribution Sustainment | 108 | 8,359 | 12 | 8,455 |
| 35 | | **108** | **26,434** | **12** | **26,530** |
| 36 | **General Plant** | | | | |
| 37 | Distribution Substation Automation | 579 | 2,162 | - | 2,741 |
| 38 | Protection, Harmonic Remediation,Communication & Rehabilitation | 192 | 1,975 | - | 2,167 |
| 39 | Mandatory Reliability Standards Compliance | 738 | 872 | - | 1,610 |
| 40 | Vehicles | 386 | 2,664 | - | 3,050 |
| 41 | Metering | - | 316 | - | 316 |
| 42 | Information Systems | - | 4,829 | - | 4,829 |
| 43 | Telecommunications | - | 315 | - | 315 |
| 44 | Buildings | - | 1,287 | - | 1,287 |
| 45 | Kootenay Long Term Facility Strategy | - | 433 | 433 | - |
| 46 | Okanagan Long Term Solution | - | 190 | 190 | - |
| 47 | PCB Environmental Compliance | - | 1,718 | 1,064 | 654 |
| 48 | Furniture & Fixtures | - | 230 | - | 230 |
| 49 | Tools & Equipment | - | 609 | - | 609 |
| 50 | | **1,895** | **17,602** | **1,688** | **17,808** |
| 51 | **TOTAL** | **57,982** | **88,365** | **11,685** | **134,663** |
| 52 | Less Closing CWIP subject to AFUDC | **(50,769)** | | **(4,197)** | |
| 53 | TOTAL CWIP not subject to AFUDC | **7,213** | | **7,488** | |

*Note: Minor differences due to rounding.*

## OPERATING AREA AND UTILITY PLANT DETAIL

AS AT DECEMBER 31, 2011

### OPERATING AREA

Trail, Warfield, Rossland, Fruitvale, Montrose, Christina Lake, Grand Forks, Greenwood, Midway, Rock Creek, Westbridge, Beaverdell, Osoyoos, Oliver, Cawston, Keremeos, Hedley, Coalmont, Tulameen, Princeton, Penticton, Naramata, Summerland, Okanagan Falls, Kelowna, Castlegar, South Slocan, Slocan, Crawford Bay, Creston, Kaslo, Salmo, all within the Province of British Columbia.

### PRODUCTION PLANT – HYDRAULIC

| Site | Voltage | Cycles | Nameplate Rating (kVA) |
|---|---|---|---|
| Lower Bonnington | 7,200 | 60 | 60,000 |
| Upper Bonnington | 2,300/7,200 | 60 | 79,400 |
| South Slocan | 7,200 | 60 | 72,000 |
| Corra Linn | 7,200 | 60 | 60,000 |

### TRANSMISSION PLANT
**Line Length (kilometers)**

| Area | 63 kV | 132/138 kV | 161 kV | 230 kV | Total |
|---|---|---|---|---|---|
| Boundary | 141.0 | 0.0 | 102.9 | 0.0 | 243.9 |
| Creston | 85.7 | 0.0 | 0.0 | 0.0 | 85.8 |
| Kelowna | 1.6 | 124.5 | 0.0 | 113.8 | 239.9 |
| Kootenay | 380.1 | 0.0 | 22.6 | 51.5 | 454.2 |
| Similkameen | 2.0 | 93.3 | 0.0 | 0.0 | 95.3 |
| South Okanagan | 161.4 | 12.5 | 16.5 | 98.3 | 288.7 |
| **Total** | **771.8** | **230.2** | **142.0** | **263.6** | **1,407.7** |

### Terminal Transformers

| Rating (MVA) | Quantity |
|---|---|
| 22.4/30 | 3 |
| 45/60 | 1 |
| 60/80 | 2 |
| 56/75 | 1 |
| 60/80/100 | 1 |
| 90/120/150 | 1 |
| 90/120/150/168 | 1 |
| 100/134/168 | 3 |
| 120/160/200 | 4 |
| 150/200/250 | 2 |
| **Total Base Capacity** | **1,608 MVA** |

*Note: Minor differences due to rounding.*

**OPERATING AREA AND UTILITY PLANT DETAIL,** cont'd

AS AT DECEMBER 31, 2011

**DISTRIBUTION PLANT**
**Line Length (kilometres)**

| | 1 Phase | | 2 Phase | | 3 Phase | | Total |
|---|---|---|---|---|---|---|---|
| | **OH** | **UG** | **OH** | **UG** | **OH** | **UG** | |
| Boundary | 461.2 | 8.8 | 29.2 | 0.0 | 349.0 | 1.5 | 849.8 |
| Creston | 346.0 | 14.1 | 9.0 | 0.0 | 281.1 | 2.9 | 653.1 |
| Kelowna | 410.2 | 264.5 | 17.7 | 0.9 | 346.6 | 211.2 | 1,251.1 |
| Kootenay | 687.1 | 33.6 | 15.7 | 0.1 | 438.0 | 24.3 | 1,198.8 |
| Similkameen | 289.9 | 17.3 | 25.5 | 0.0 | 390.3 | 5.7 | 728.7 |
| South Okanagan | 468.0 | 65.2 | 52.8 | 0.1 | 340.5 | 22.0 | 948.5 |
| **Total** | **2,662.3** | **403.6** | **149.9** | **1.1** | **2,145.6** | **267.5** | **5,629.9** |

OH = Overhead UG = Underground

**Distribution Transformers (HV < 60 kV)**

| | Overhead | | Underground | | Total | |
|---|---|---|---|---|---|---|
| **Rating (kVA)** | **Quantity** | **Capacity (kVA)** | **Quantity** | **Capacity (kVA)** | **Quantity** | **Capacity (kVA)** |
| 0-100 | 29,392 | 889,151 | 4,294 | 319,310 | 33,686 | 1,208,461 |
| 101-500 | 117 | 21,432 | 1,104 | 335,354 | 1,221 | 356,786 |
| 501-1,500 | 8 | 12,300 | 147 | 148,500 | 155 | 160,800 |
| **Total** | **29,517** | **922,883** | **5,545** | **803,164** | **35,062** | **1,726,047** |

**Distribution Substation (HV > 60 kV)**

| Rating (kVA) | Quantity | Rating (kVA) | Quantity |
|---|---|---|---|
| 500 | 3 | 11,200 | 1 |
| 1,500 | 4 | 11,250 | 9 |
| 2,000 | 1 | 12,000 | 8 |
| 2,800 | 3 | 13,400 | 1 |
| 3,750 | 1 | 13,500 | 1 |
| 4,500 | 1 | 16,000 | 2 |
| 5,000 | 1 | 24,000 | 21 |
| 6,000 | 5 | 28,500 | 1 |
| 7,500 | 5 | 30,000 | 2 |
| 10,000 | 5 | 31,500 | 1 |
| | | **1,040,000** | **76** |

*Note: Minor differences due to rounding.*

# ANALYSIS OF DEFERRED CHARGES AND CREDITS

## FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Balance at Dec. 31, 2010 | Additions and Transfers | Amortized to Other Accounts | Amortization | Balance at Dec. 31, 2011 |
|---|---|---|---|---|---|---|
| | | | | ($000s) | | |
| 1 | **Demand Side Management** | | | | | |
| 2 | Demand Side Management Additions | 20,961 | 5,917 | - | (1,859) | 25,020 |
| 3 | Tax Impact | (12,528) | (1,568) | - | 493 | (13,603) |
| 4 | | **8,433** | **4,349** | **-** | **(1,366)** | **11,417** |
| 5 | **Deferred Regulatory Expense** | | | | | |
| 6 | 2009 Flow-through and ROE Sharing Mechanism Adjustments | (1,090) | - | 1,090 | - | - |
| 7 | 2010 Flow-through and ROE Sharing Mechanism Adjustments | (2,061) | - | 1,681 | - | (380) |
| 8 | 2011 Flow-through and ROE Sharing Mechanism Adjustments | - | (6,887) | - | - | (6,887) |
| 9 | 2010 Revenue Requirements | 75 | - | - | (75) | - |
| 10 | Tax Impact | (22) | - | - | 22 | - |
| 11 | 2011 Revenue Requirements | 35 | 41 | - | - | 76 |
| 12 | Tax Impact | (10) | (11) | - | - | (21) |
| 13 | Renewal of BCH Power Purchase Agreement | 109 | 29 | - | - | 138 |
| 14 | Tax Impact | (33) | (8) | - | - | (41) |
| 15 | FortisBC Energy (Terasen Gas) ROE and Capital Structure Application | 76 | - | - | (76) | - |
| 16 | Tax Impact | (23) | - | - | 23 | - |
| 17 | Section 5 Provincial Transmission Inquiry | 90 | - | - | (90) | - |
| 18 | Tax Impact | (27) | - | - | 27 | - |
| 19 | BC Hydro Waneta Transaction Application | 284 | - | - | (95) | 189 |
| 20 | Tax Impact | (85) | - | - | 28 | (57) |
| 21 | BC Hydro Amendment to 3808 (PPA) Proceedings | 76 | - | - | (38) | 38 |
| 22 | Tax Impact | (23) | - | - | 12 | (12) |
| 23 | 2009 Cost of Service Analysis and Rate Design Application | 1,708 | 418 | - | (531) | 1,595 |
| 24 | Tax Impact | (503) | (111) | - | 153 | (460) |
| 25 | Shaw Application for Transmission Facility Access | 288 | 80 | - | - | 367 |
| 26 | Tax Impact | (82) | (21) | - | - | (103) |
| 27 | Tariff Amendment - Adaptive Street Lighting | 3 | - | (3) | - | - |
| 28 | Tax Impact | (1) | - | 1 | - | - |
| 29 | Residential Inclining Block Rate and Industrial Stepped Rate Application | - | 189 | - | - | 189 |
| 30 | Tax Impact | - | (50) | - | - | (50) |
| 31 | Implementation of New Rate Structures | - | 22 | - | - | 22 |
| 32 | Tax Impact | - | (6) | - | - | (6) |
| 33 | Irrigation Rate Payer Consultation and Load Research | - | 18 | - | - | 18 |
| 34 | Tax Impact | - | (5) | - | - | (5) |
| 35 | 2012 Integrated System Plan and 2012 - 2013 Revenue Requirements | 75 | 1,444 | - | - | 1,519 |
| 36 | Tax Impact | (21) | (418) | - | - | (439) |
| 37 | Section 71 Filing (Waneta Expansion Power Purchase Agreement) | 360 | 187 | - | (120) | 427 |
| 38 | Tax Impact | (103) | (49) | - | 34 | (118) |
| 39 | | **(903)** | **(5,138)** | **2,768** | **(727)** | **(3,999)** |
| 40 | | | | | | |
| 41 | **Preliminary and Investigative Charges** | **2,435** | **1,126** | **(798)** | **-** | **2,764** |
| 42 | | | | | | |
| 43 | **Other Deferred Charges and Credits** | | | | | |
| 44 | Trail Office Lease Costs | 155 | - | - | (12) | 143 |
| 45 | Trail Office Rental to SD20 | (729) | - | (57) | - | (786) |
| 46 | Prepaid Pension Costs | 7,448 | (468) | - | - | 6,979 |
| 47 | Tax Impact | (757) | 124 | - | - | (633) |
| 48 | Other Post Employment Benefits (OPEB) | (10,321) | (3,053) | - | - | (13,374) |
| 49 | Tax Impact | 3,211 | 809 | - | - | 4,020 |
| 50 | Resource Plan | 789 | (789) | - | - | - |
| 51 | Tax Impact | (244) | 244 | - | - | - |
| 52 | Revenue Protection | 221 | 219 | - | (221) | 219 |
| 53 | Tax Impact | (63) | (58) | - | 63 | (58) |
| 54 | Demand Side Management Study | 259 | - | - | (86) | 173 |
| 55 | Tax Impact | (75) | - | - | 25 | (50) |
| 56 | Princeton Light and Power Computer Software | 40 | - | - | (23) | 17 |
| 57 | Princeton Light and Power Deferred Pension Credit | (46) | - | - | 12 | (35) |
| 58 | Right of Way Reclamation (Pine Beetle Kill) | 2,006 | - | - | (251) | 1,755 |
| 59 | Tax Impact | (622) | - | - | 78 | (544) |
| 60 | International Financial Reporting Standards | 214 | - | - | (214) | - |
| 61 | Tax Impact | (61) | - | - | 61 | - |
| 62 | Right of Way Encroachment Litigation | 91 | - | - | - | 91 |
| 63 | Tax Impact | (28) | - | - | - | (28) |
| 64 | Joint Pole Use Audit 2008 | 93 | - | - | (31) | 62 |
| 65 | Tax Impact | (28) | - | - | 9 | (19) |
| 66 | Mandatory Reliability Standards | 848 | 203 | - | - | 1,051 |
| 67 | Tax Impact | (242) | (54) | - | - | (296) |
| 68 | Harmonized Sales Tax Implementation Project | 222 | - | - | (222) | - |
| 69 | Tax Impact | (63) | - | - | 63 | - |
| 70 | Pope & Talbot Litigation | 23 | - | - | (23) | - |
| 71 | Tax Impact | (7) | - | - | 7 | - |
| 72 | US Generally Accepted Accounting Principles | - | 712 | - | - | 712 |
| 73 | Tax Impact | - | (189) | - | - | (189) |
| 74 | | **2,333** | **(2,300)** | **(57)** | **(766)** | **(790)** |

*Note: Minor differences due to rounding.*

# ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Balance at Dec. 31, 2010 | Additions and Transfers | Amortized to Other Accounts | Amortization | Balance at Dec. 31, 2011 |
|---|---|---|---|---|---|---|
| | | | | ($000s) | | |
| 75 | **Deferred Debt Issue Costs** | | | | | |
| 76 | Series F | 70 | - | - | (39) | 31 |
| 77 | Series G | 93 | - | - | (7) | 86 |
| 78 | Series H | 67 | - | - | (13) | 54 |
| 79 | Series I | 157 | - | - | (14) | 142 |
| 80 | Series 04-1 | 858 | - | - | (219) | 638 |
| 81 | Tax Impact | (61) | - | - | 16 | (45) |
| 82 | Series 05-1 | 1,032 | - | - | (42) | 990 |
| 83 | Tax Impact | (376) | - | - | 15 | (361) |
| 84 | Series 07-1 | 1,153 | - | - | (32) | 1,121 |
| 85 | Tax Impact | (320) | (88) | - | 9 | (400) |
| 86 | MTN - 2009 | 957 | - | - | (34) | 924 |
| 87 | Tax Impact | (118) | (59) | - | 4 | (173) |
| 88 | MTN - 2010 | 941 | (74) | - | (22) | 846 |
| 89 | Tax Impact | (54) | (37) | - | 1 | (89) |
| 90 | | **4,399** | **(258)** | **-** | **(377)** | **3,765** |
| 91 | | | | | | |
| 92 | **TOTAL DEFERRED CHARGES (RATE BASE)** | **16,698** | **(2,220)** | **1,914** | **(3,236)** | **13,157** |
| 93 | **Deferred Charges (Non Rate Base)** | | | | | |
| 94 | Advanced Metering Infrastructure (AMI) Costs | 920 | 1,198 | - | - | 2,118 |
| 95 | **GRAND TOTAL DEFERRED CHARGES** | **17,618** | **(1,022)** | **1,914** | **(3,236)** | **15,275** |

*Note: Minor differences due to rounding.*

*Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.*

*Row 94: Pursuant to the Negotiated Settlement Agreements for the 2010 and 2011 Revenue Requirements, AMI costs were collected in a non-rate base deferral account that collected AFUDC.*

# ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

## AS AT DECEMBER 31, 2011

| Line | Account | | Acc. Prov. For Depreciation Dec. 31, 2010 | Approved Deprec. Rate | Asset Balance Dec. 31, 2010 | Depreciation Expense Dec. 31, 2011 | Charges less Recoveries | Acc. Prov. For Depreciation Dec. 31, 2011 |
|---|---|---|---|---|---|---|---|---|
| | | | | | ($000s) | | | |
| | | Hydraulic Production Plant | | | | | | |
| 1 | 330 | Land Rights | (570) | 2.6% | 962 | 25 | - | (545) |
| 2 | 331 | Structures and Improvements | 5,343 | 1.2% | 12,609 | 151 | (38) | 5,456 |
| 3 | 332 | Reservoirs, Dams and Waterways | 5,535 | 1.7% | 26,644 | 453 | (48) | 5,940 |
| 4 | 333 | Water Wheels, Turbines & Generators | 1,608 | 2.2% | 73,448 | 1,616 | (459) | 2,765 |
| 5 | 334 | Accessory Electrical Equipment | 7,613 | 2.4% | 32,934 | 790 | (829) | 7,574 |
| 6 | 335 | Other Power Plant Equipment | 9,219 | 2.3% | 41,642 | 958 | - | 10,177 |
| 7 | 336 | Roads, Railroads, and Bridges | 486 | 1.4% | 1,287 | 18 | - | 504 |
| 8 | | | 29,233 | 2.1% | 189,525 | 4,011 | (1,374) | 31,870 |
| 9 | | Transmission Plant | | | | | | |
| 10 | 350 | Land Rights - R/W | (62) | 0.0% | 7,271 | - | - | (62) |
| 11 | 350.1 | Land Rights - Clearing | 2,062 | 1.6% | 6,236 | 104 | - | 2,166 |
| 12 | 353 | Station Equipment | 2,323 | 3.0% | 150,925 | 1,900 | (2,385) | 1,839 |
| 13 | 355 | Poles, Towers & Fixtures | 8,318 | 3.0% | 89,033 | 2,671 | (1,020) | 9,969 |
| 14 | 356 | Conductors and Devices | 4,651 | 3.0% | 86,903 | 2,607 | (1,005) | 6,253 |
| 15 | 359 | Roads and Trails | 89 | 2.9% | 1,121 | 33 | - | 121 |
| 16 | | | 17,381 | 2.1% | 341,489 | 7,316 | (4,409) | 20,287 |
| 17 | | Distribution Plant | | | | | | |
| 18 | 360 | Land Rights - R/W | (868) | 0.0% | 2,689 | - | - | (868) |
| 19 | 360.1 | Land Rights - Clearing | (28) | 2.1% | 9,964 | 209 | - | 181 |
| 20 | 362 | Station Equipment | 68,899 | 3.0% | 199,086 | 8,579 | (1,921) | 75,557 |
| 21 | 364 | Poles, Towers & Fixtures | 40,730 | 3.0% | 137,498 | 4,125 | (747) | 44,109 |
| 22 | 365 | Conductors and Devices | 62,546 | 3.0% | 224,957 | 6,749 | (1,204) | 68,091 |
| 23 | 368 | Line Transformers | 20,076 | 2.9% | 104,732 | 3,049 | (1,267) | 21,858 |
| 24 | 369 | Services | 6,511 | 0.0% | 7,292 | 36 | - | 6,547 |
| 25 | 370 | Meters | 5,294 | 3.5% | 13,593 | 483 | (216) | 5,561 |
| 26 | 371 | Installation on Customers' Premises | (3,413) | 0.0% | 938 | - | - | (3,413) |
| 27 | 373 | Street Lighting and Signal Systems | 3,464 | 2.4% | 11,485 | 278 | (104) | 3,638 |
| 28 | | | 203,212 | 3.3% | 712,234 | 23,507 | (5,459) | 221,261 |
| 29 | | General Plant | | | | | | |
| 30 | 389 | Land | 897 | 0.0% | 12,093 | - | - | 897 |
| 31 | 390 | Structures - Frame & Iron | 536 | 0.8% | 337 | 3 | - | 539 |
| 32 | 390.1 | Structures - Masonry | 4,194 | 3.0% | 22,248 | 667 | - | 4,861 |
| 33 | 391 | Office Furniture & Equipment | 4,241 | 7.5% | 5,729 | 430 | - | 4,671 |
| 34 | 391.1 | Computer Equipment | 41,529 | 10.6% | 62,875 | 6,665 | (193) | 48,001 |
| 35 | 392 | Transportation Equipment | 1,484 | 0.4% | 17,755 | 71 | (261) | 1,293 |
| 36 | 394 | Tools and Work Equipment | 7,211 | 9.5% | 11,296 | 1,073 | (4) | 8,280 |
| 37 | 397 | Communication Structures and Equipment | 7,288 | 6.0% | 23,238 | 1,394 | (16) | 8,666 |
| 38 | | | 67,381 | 6.6% | 155,572 | 10,303 | (474) | 77,210 |
| 39 | | | | | | | | |
| 40 | 108 | Total Accumulated Depreciation | 317,207 | 3.2% | 1,398,820 | 45,137 | (11,717) | 350,628 |
| 41 | | | | | | | | |
| 42 | | Deduct - Portion of CIAC Depreciated | | | | (4,092) | | |
| 43 | | | | | | | | |
| 44 | 403 | Depreciation Expense | | | | 41,045 | | |
| 45 | | | | | | | | |
| 46 | | Other | | | | | | |
| 47 | 114 | Utility Plant Acquisition Adjustment | 5,024 | | 11,912 | 186 | | 5,210 |
| 48 | 390.1 | Leasehold Improvements | 2,526 | | 4,796 | 571 | | 3,097 |
| 49 | | Rate Stabilization Adjustment | (1,554) | 10.00% | | 311 | | (1,243) |
| 50 | | Total Accumulated Amortization | 5,996 | | | 1,068 | | 7,064 |
| 51 | | | | | | | | |
| 52 | | Accumulated Amortization per | | | | | | |
| 53 | | Balance Sheet | 323,203 | | | 42,113 | | 357,692 |

*Note: Minor differences due to rounding.*

# ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2011

| | Lag Days Calculation | Lag (Lead) Days | 2011 Actual ($000s) | 2011 Extended ($000s) | Weighted Average Lag Days |
|---|---|---|---|---|---|
| 1 | **Revenue** | | | | |
| 2 | Tariff Revenue | 50.5 | 277,090 | 13,993 | |
| 3 | *Other Revenue:* | | | | |
| 4 | Apparatus and Facilities Rental | 26.6 | 3,709 | 99 | |
| 5 | Contract Revenue | 44.3 | 1,826 | 81 | |
| 6 | Miscellaneous Revenue | 31.8 | 1,791 | 57 | |
| 7 | Investment Income | 15.0 | 180 | 3 | |
| 8 | | | 284,596 | 14,232 | 50.0 |
| 9 | | | | | |
| 10 | **Expenses** | | | | |
| 11 | Power Purchases | 42.2 | 71,519 | 3,018 | |
| 12 | Wheeling | 40.2 | 4,281 | 172 | |
| 13 | Water Fees | (1.0) | 9,047 | (9) | |
| 14 | *Operating Labour:* | | | | |
| 15 | Salaries & Wages | 5.3 | 13,463 | 71 | |
| 16 | Employee Benefits | 13.2 | 10,501 | 139 | |
| 17 | Contracted Manpower | 50.6 | 8,304 | 420 | |
| 18 | Property Tax | 2.6 | 13,408 | 35 | |
| 19 | Rental of T&D Facilities | 47.8 | 3,033 | 145 | |
| 20 | Office Lease - Kelowna | (15.2) | 827 | (13) | |
| 21 | Office Lease - Trail | 91.3 | 1,212 | 111 | |
| 22 | Materials | 45.6 | 4,407 | 201 | |
| 23 | Insurance | (182.5) | 550 | (100) | |
| 24 | Income Tax | 15.2 | 9,417 | 143 | |
| 25 | Interest | 82.9 | 38,893 | 3,224 | |
| 26 | | | 188,863 | 7,557 | 40.0 |
| 27 | | | | | |
| 28 | **Net Lag/(Lead) Days** | | | | **10.0** |
| 29 | | | | | |
| 30 | | | | | |
| 31 | **Working Capital Allowance** | | | ($000s) | |
| 32 | | | | | |
| 33 | **Lead-Lag Study Allowance:** | | | | |
| 34 | Net Lag Days/365 times Expenses | | | | 5,173 |
| 35 | | | | | |
| 36 | **Add Funds Unavailable:** | | | | |
| 37 | Average Customer Loans (related to energy management) | | | 2,762 | |
| 38 | Average Employee Loans | | | 371 | |
| 39 | Average of Uncollectable Accounts | | | 1,024 | |
| 40 | Average Inventory (forecast monthly average investment) | | | 539 | |
| 41 | | | | | 4,696 |
| 42 | **Less Funds Available:** | | | | |
| 43 | Average Customer Deposits | | | 4,089 | |
| 44 | Average HST | | | 825 | |
| 45 | | | | | 4,915 |
| 46 | | | | | |
| 47 | **2011 ALLOWANCE FOR WORKING CAPITAL** | | | | **4,954** |

*Note: Minor differences due to rounding.*

## ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Additions to Plant in Service * ($000s) | Months in Rate Base | Weighted Value ($000s) |
|---|---|---|---|---|
| 1 | January | 1,061 | 11.5 | 1,017 |
| 2 | February | 2,605 | 10.5 | 2,279 |
| 3 | March | 41,220 | 9.5 | 32,632 |
| 4 | April | 11,626 | 8.5 | 8,235 |
| 5 | May | 2,676 | 7.5 | 1,672 |
| 6 | June | 3,382 | 6.5 | 1,832 |
| 7 | July | 2,527 | 5.5 | 1,158 |
| 8 | August | 10,285 | 4.5 | 3,857 |
| 9 | September | 6,009 | 3.5 | 1,753 |
| 10 | October | 8,548 | 2.5 | 1,781 |
| 11 | November | 8,241 | 1.5 | 1,030 |
| 12 | December | 30,603 | 0.5 | 1,275 |
| 13 | **Total** | **128,783** | | **58,522** |
| 14 | Less Simple Average | | | 64,391 |
| 15 | Adjustment to Capital Additions | | | **(5,870)** |

16 ** Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:*

| | | |
|---|---|---|
| 17 | Gross Plant in Service Additions | 134,663 |
| 18 | CIAC | (5,880) |
| 19 | Net Capital Additions | **128,783** |

*Note: Minor differences due to rounding.*

## BALANCE SHEET – ASSETS

AS AT DECEMBER 31, 2011

| Line | Account | December 31 2011 | December 31 2010 | Increase / (Decrease) |
|---|---|---|---|---|
| | | | ($000s) | |
| 1 | Utility Plant | | | |
| 2 | | | | |
| 3 | 101 Utility Plant In Service | 1,531,831 | 1,403,617 | 128,214 |
| 4 | 105 Utility Plant Held for Future Use | - | - | - |
| 5 | 107 Plant Under Construction | | | |
| 6 | Not Subject to AFUDC | 7,488 | 7,213 | 274 |
| 7 | Subject to AFUDC | 4,197 | 50,769 | (46,572) |
| 8 | 114 Plant Acquisition Adjustment | 11,912 | 11,912 | - |
| 9 | | 1,555,427 | 1,473,511 | 500,079 |
| 10 | | | | |
| 11 | 108 Accumulated Depreciation | (350,628) | (317,207) | (33,421) |
| 12 | 111 Accumulated Amortization | (8,307) | (7,550) | (757) |
| 13 | Rate Stabilization Account [(1)] | 1,243 | 1,554 | (311) |
| 14 | | 1,197,735 | 1,150,308 | 47,428 |
| 15 | | | | |
| 16 | Current Assets | | | |
| 17 | 131 Cash | - | - | - |
| 18 | 142 Accounts Receivable | 41,665 | 49,496 | (7,831) |
| 19 | 144 Allowance for Doubtful Accounts | (950) | (1,058) | 108 |
| 20 | 146 Accounts Receivable - Affiliated Companies | 863 | 661 | 202 |
| 21 | 154 Materials and Supplies | 439 | 467 | (28) |
| 22 | 166 Prepayments | 902 | 1,094 | (192) |
| 23 | | 42,919 | 50,660 | (7,741) |
| 24 | | | | |
| 25 | Deferred Charges | | | |
| 26 | 186 Energy Management | 11,417 | 8,433 | 2,984 |
| 27 | 186 Regulatory Expense | (3,999) | (903) | (3,096) |
| 28 | 183 Preliminary Investigation | 2,764 | 2,435 | 329 |
| 29 | 186 Other Deferred Charges & Credits | (790) | 2,333 | (3,123) |
| 30 | 181 Debt Issue Expense | 3,765 | 4,399 | (635) |
| 31 | | 13,157 | 16,698 | (3,541) |
| 32 | | | | |
| 33 | 186 Non-Rate Base Assets [(2)] | 148,953 | 135,295 | 13,658 |
| 34 | | | | |
| 35 | **Total Assets** | **1,402,764** | **1,352,961** | **49,803** |

(1) *The Negotiated Settlement for 2000-2002 included a provision for a notional funding adjustment to prior years' depreciation, in order to ensure that rate increases would not exceed 5 per cent per year during the term of the settlement. The Rate Stabilization Account (RSA) adjustment was to be booked as used and was required only in 2001. Pursuant to the 2006 Revenue Requirements Decision Order G-58-06, the RSA is to be amortized over a ten-year period beginning in 2006.*

(2) *Table of Non-Rate Base Assets:*

| | 2011 | 2010 |
|---|---|---|
| Other Post-Retirement Benefits | 16,663 | 14,121 |
| Brilliant Terminal Station (BTS) Lease Costs | 5,614 | 5,098 |
| Trail Office Lease Costs | 1,101 | 1,249 |
| Future Income Tax | 99,203 | 90,044 |
| Asset Retirement Obligation (ARO) Regulated Asset | 796 | 340 |
| Advanced Metering Infrastructure (AMI) Costs | 2,118 | 920 |
| BTS Capital Lease Asset less Accum Depn | 20,319 | 20,644 |
| ARO Asset less Accum Depn | 3,139 | 2,879 |
| | **148,953** | **135,295** |

*Note: Minor differences due to rounding.*

## BALANCE SHEET – LIABILITIES

AS AT DECEMBER 31, 2011

| Line | Account | | December 31 2011 | December 31 2010 | Increase / (Decrease) |
|---|---|---|---|---|---|
| | | | | ($000s) | |
| 1 | | Shareholders' Equity | | | |
| 2 | | | | | |
| 3 | 201 | Common Shares | 180,122 | 180,122 | - |
| 4 | 216 | Retained Earnings | 268,691 | 238,424 | 30,267 |
| 5 | | | 448,813 | 418,546 | 30,267 |
| 6 | | | | | |
| 7 | | Long Term Debt | | | |
| 8 | 221 | Secured Debentures - Series F | 15,000 | 15,000 | - |
| 9 | 221 | Secured Debentures - Series G | 25,000 | 25,000 | - |
| 10 | 221 | Unsecured Debentures - Series H | 25,000 | 25,000 | - |
| 11 | 221 | Unsecured Debentures - Series I | 25,000 | 25,000 | - |
| 12 | 221 | Unsecured Debentures - Series 04-1 | 140,000 | 140,000 | - |
| 13 | 224 | Unsecured Debentures - Series 05-1 | 100,000 | 100,000 | - |
| 14 | 224 | Unsecured Debentures - Series 07-1 | 105,000 | 105,000 | - |
| 15 | 224 | Unsecured Debentures - Series-1 MTN | 105,000 | 105,000 | - |
| 16 | 224 | Unsecured Debentures - Series 2 MTN | 100,000 | 100,000 | - |
| 17 | 224 | Term Bank Loans & Other | 8,992 | - | 8,992 |
| 18 | | | 648,992 | 640,000 | 8,992 |
| 19 | | | | | |
| 20 | | | | | |
| 21 | | Current and Accrued Liabilities | | | |
| 22 | 232 | Accounts Payable and Accrued Liabilities | 39,710 | 53,020 | (13,310) |
| 23 | 234 | Bank Loans | 8,486 | 1,122 | 7,364 |
| 24 | 235 | Customers' Security Deposits | 3,976 | 4,263 | (287) |
| 25 | 254 | Income Taxes Payable | 4,990 | 2,460 | 2,530 |
| 26 | 237 | Accrued Interest | 4,545 | 4,545 | - |
| 27 | 239 | Long Term Debt Due Within One Year | - | - | - |
| 28 | 261 | Insurance Reserve | 447 | 448 | (1) |
| 29 | | | 62,154 | 65,857 | (3,703) |
| 30 | | | | | |
| 31 | | | | | |
| 32 | | Deferred Credits | | | |
| 33 | 252 | Contributions in Aid of Construction | 95,551 | 93,763 | 1,788 |
| 34 | | | | | |
| 35 | 254 | Future Income Tax | 418 | 418 | - |
| 36 | 254 | Future Income Tax (non-rate base) | 99,203 | 90,044 | 9,159 |
| 37 | 256 | Other Non-Rate Base Obligations & Liabilities (1) | 47,633 | 44,332 | 3,302 |
| 38 | | | 147,254 | 134,794 | 12,461 |
| 39 | | | | | |
| 40 | | | | | |
| 41 | | **Total Liabilities** | **1,402,764** | **1,352,961** | **49,804** |

| *Other Non-Rate Base Obligations & Liabilities:* | 2011 | 2010 |
|---|---|---|
| BTS Capital Lease Obligation | 25,934 | 25,743 |
| Trail Office Lease Obligation | 1,101 | 1,249 |
| Other Post-Retirement Benefit Liability | 16,663 | 14,121 |
| ARO Liability | 3,935 | 3,219 |
| | **47,633** | **44,332** |

*Note: Minor differences due to rounding.*

## SCHEDULE 2 – EARNED RETURN

| | | Normalized 2010 | Decision 2011 | Actual 2011 | Normalized 2011 | Change from Decision |
|---|---|---|---|---|---|---|
| 1 | SALES VOLUME (GWh) | 3,094 | 3,162 | 3,143 | 3,129 | (32) |
| 2 | | | | | | |
| 3 | | | | ($000s) | | |
| 4 | ELECTRICITY SALES REVENUE | 250,235 | 278,783 | 277,090 | 275,898 | (2,886) |
| 5 | | | | | | |
| 6 | EXPENSES | | | | | |
| 7 | Power Purchases | 73,733 | 81,212 | 71,519 | 70,458 | (10,754) |
| 8 | Water Fees | 9,256 | 9,381 | 9,047 | 9,047 | (334) |
| 9 | Wheeling | 4,050 | 3,338 | 4,281 | 4,281 | 943 |
| 10 | Net O&M Expense | 36,619 | 43,108 | 42,299 | 42,299 | (809) |
| 11 | Property Tax | 12,238 | 13,940 | 13,408 | 13,408 | (532) |
| 12 | Depreciation and Amortization | 41,771 | 45,498 | 45,349 | 45,349 | (149) |
| 13 | Other Income | (6,453) | (5,455) | (7,506) | (7,506) | (2,051) |
| 14 | Incentive Adjustments | (629) | (2,770) | 4,116 | 4,116 | 6,886 |
| 15 | UTILITY INCOME BEFORE TAX | 79,650 | 90,531 | 94,577 | 94,446 | 3,915 |
| 16 | Less: | | | | | |
| 17 | INCOME TAXES | 5,048 | 6,733 | 9,417 | 9,382 | 2,649 |
| 18 | | | | | | |
| 19 | EARNED RETURN | 74,602 | 83,798 | 85,160 | 85,064 | 1,266 |
| 20 | RETURN ON RATE BASE | | | | | |
| 21 | Utility Rate Base | 945,637 | 1,093,241 | 1,065,892 | 1,065,892 | (27,349) |
| 22 | Return on Rate Base | 7.89% | 7.67% | 7.99% | 7.98% | 0.32% |

*Note: Minor differences due to rounding.*

## WEATHER NORMALIZATION

FOR THE YEAR ENDING DECEMBER 31, 2011

| Temperature | Heating Degree Days | Cooling Degree Days |
|---|---|---|
| Actual | 3,374 | 236 |
| Normal | 3,327 | 277 |
| Difference | 47 | (41) |

### Notional Impact of Weather Normalization Adjustment

| | |
|---|---|
| Energy Adjustment (GWh) | |
| Residential | (10) |
| Wholesale | (2) |
| Losses | (1) |
| | (14) |
| Revenue Adjustment ($000s) | |
| Residential | (1,049) |
| Wholesale | (143) |
| | (1,192) |
| Power Purchase Expense Adjustment ($000s) | |
| Energy | (476) |
| Capacity | (585) |
| | (1,061) |

## ELECTRIC OPERATING REVENUES BY RATE CLASS

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Customers at Dec. 31, 2011 | Energy Sales (GWh) | Revenue ($000s) | Average Use (kWh) | Revenue per kWh Sold (cents) |
|---|---|---|---|---|---|---|
| 1 | Residential | 98,795 | 1,260 | 129,436 | 12,754 | 10.27 |
| 2 | Commercial | 11,525 | 652 | 62,290 | 56,573 | 9.55 |
| 3 | Industrial | 39 | 282 | 21,842 | | 7.75 |
| 4 | Other | 2,895 | 53 | 5,149 | | 9.72 |
| 5 | Total without Wholesale | 113,254 | 2,247 | 218,717 | 19,840 | 9.73 |
| 6 | Wholesale | 7 | 896 | 58,373 | | 6.51 |
| 7 | Total | 113,261 | 3,143 | 277,090 | 27,750 | 8.82 |

*Note: Minor differences due to rounding.*

## ANALYSIS OF POWER PURCHASES AND GENERATION OF POWER

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Volume | | Expense | |
|---|---|---|---|---|---|
| | | 2011 | 2010 | 2011 | 2010 |
| 1 | Capacity | (MW Months) | | ($000s) | |
| 2 | B.C. Hydro | 1,727 | 1,852 | 10,268 | 10,142 |
| 3 | Market | 438 | 467 | 2,864 | 2,243 |
| 4 | | | | | |
| 5 | Energy | (GWh) | | | |
| 6 | Columbia Power Corp. | 922 | 922 | 32,115 | 33,053 |
| 7 | B.C. Hydro | 508 | 600 | 17,744 | 19,402 |
| 8 | IPPs | 17 | 37 | 205 | 914 |
| 9 | Market | 487 | 291 | 9,433 | 8,222 |
| 10 | Surplus Sales | (10) | (49) | (63) | (1,000) |
| 11 | CPC Loss & Special Adjustments | - | (4) | - | - |
| 12 | | 1,924 | 1,796 | 72,567 | 72,977 |
| 13 | | | | | |
| 14 | Generation | 1,527 | 1,530 | | |
| 15 | Total System Load | 3,451 | 3,326 | | |
| 16 | | | | | |
| 17 | Adjustment for Upgrade Projects | - | - | (595) | (398) |
| 18 | Other Adjustments | - | - | (453) | (615) |
| 19 | Company Use | (14) | (12) | - | - |
| 20 | Line and Transformer Losses | (294) | (268) | - | - |
| 21 | Total Electricity Sales | 3,143 | 3,046 | 71,519 | 71,964 |

## ANALYSIS OF WHEELING EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | 2011 | 2010 |
|---|---|---|---|
| | | ($000s) | |
| 1 | B.C. Hydro - Vernon | 3,720 | 3,550 |
| 2 | B.C. Hydro - Lambert | 458 | 450 |
| 3 | Miscellaneous | 103 | 50 |
| 4 | Total Wheeling Expense | 4,281 | 4,050 |

*Note: Minor differences due to rounding.*

# ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

| Line | Account | | 2011 | 2010 | Change |
|---|---|---|---|---|---|
| | | | | ($000s) | |
| 1 | | GENERATION | | | |
| 2 | 535R | Supervision & Administration | 666 | 584 | 82 |
| 3 | 536 | Water Fees | 9,047 | 9,256 | (209) |
| 4 | 542 | Structures | 697 | 651 | 47 |
| 5 | 543 | Dams & Waterways | 270 | 204 | 65 |
| 6 | 544 | Electric Plant | 534 | 627 | (93) |
| 7 | 545 | Other Plant | 271 | 134 | 137 |
| 8 | | | 11,485 | 11,456 | 29 |
| 9 | | | | | |
| 10 | | OTHER POWER SUPPLY | | | |
| 11 | 555 | Purchased Power | 71,519 | 71,964 | (446) |
| 12 | 556 | System Control | 1,805 | 1,653 | 152 |
| 13 | | | 73,324 | 73,617 | (293) |
| 14 | | | | | |
| 15 | | TRANSMISSION & DISTRIBUTION | | | |
| 16 | 560R-1 | Supervision & Administration | 1,634 | 768 | 866 |
| 17 | 560R-2 | System Planning | 2,148 | 1,450 | 699 |
| 18 | 561 | Load Dispatching | 1,193 | 1,107 | 86 |
| 19 | 562 | Transmission Station Expense | 902 | 658 | 245 |
| 20 | 563R-1 | Transmission Line Maintenance | 570 | 179 | 391 |
| 21 | 563R-2 | Transmission ROW Maintenance | 1,218 | 264 | 954 |
| 22 | 565 | Wheeling | 4,281 | 4,050 | 231 |
| 23 | 567 | Rents | 3,033 | 3,115 | (82) |
| 24 | 583R-1 | Distribution Line Maintenance | 3,304 | 2,926 | 379 |
| 25 | 583R-2 | Distribution ROW Maintenance | 3,684 | 2,153 | 1,531 |
| 26 | 586 | Meter Expenses | 1,030 | 986 | 44 |
| 27 | 592 | Distribution Station Expense | 1,313 | 1,273 | 41 |
| 28 | 596 | Street Lighting | 78 | 81 | (3) |
| 29 | 598 | Other Plant | 249 | 297 | (48) |
| 30 | | | 24,639 | 19,306 | 5,333 |
| 31 | | | | | |
| 32 | | CUSTOMER SERVICE | | | |
| 33 | 901 | Supervision & Administration | 1,128 | 1,224 | (95) |
| 34 | 902 | Meter Reading | 2,030 | 1,791 | 238 |
| 35 | 903 | Customer Billing | 646 | 615 | 30 |
| 36 | 904 | Credit & Collections | 683 | 639 | 45 |
| 37 | 910 | Customer Assistance | 2,462 | 2,202 | 259 |
| 38 | | | 6,949 | 6,471 | 478 |

*Note: Minor differences due to rounding.*

## **ELECTRIC OPERATING AND MAINTENANCE EXPENSE,** cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

| Line | Account | | 2011 | 2010 | Change |
|---|---|---|---|---|---|
| | | | | ($000s) | |
| 39 | | | | | |
| 40 | | ADMINISTRATIVE AND GENERAL | | | |
| 41 | 920 | Salaries | | | |
| 42 | 920.1 | Executive & Senior Management | 1,371 | 1,167 | 203 |
| 43 | 920.2 | Legal | 687 | 646 | 42 |
| 44 | 920.3 | Human Resources | 788 | 840 | (52) |
| 45 | 920.4 | Finance & Accounting | 1,065 | 1,037 | 28 |
| 46 | 920.6 | Information Services | 903 | 997 | (94) |
| 47 | 920.7 | Materials Management | 184 | 214 | (30) |
| 48 | | Other | 288 | 256 | 32 |
| 49 | | | 5,287 | 5,157 | 129 |
| 50 | | | | | |
| 51 | 921 | Expenses | | | |
| 52 | 921.1 | Executive & Senior Management | 142 | 116 | 26 |
| 53 | 921.2 | Legal | 87 | 160 | (73) |
| 54 | 921.3 | Human Resources | 182 | 119 | 63 |
| 55 | 921.4 | Finance & Accounting | 80 | 128 | (49) |
| 56 | 921.6 | Information Services | 638 | 672 | (34) |
| 57 | 921.7 | Materials Management | (3) | 132 | (134) |
| 58 | | Other | 390 | 477 | (87) |
| 59 | | | 1,516 | 1,803 | (287) |
| 60 | | | | | |
| 61 | 923 | Special Services | 966 | 1,170 | (204) |
| 62 | 924 | Insurance | 550 | 676 | (126) |
| 63 | 932 | Maintenance to General Plant | 1,719 | 1,859 | (140) |
| 64 | 933 | Transportation Equipment Expenses | 712 | 373 | 339 |
| 65 | | | 3,947 | 4,078 | (131) |
| 66 | | | | | |
| 67 | | TOTAL | 127,146 | 121,889 | 5,257 |
| 68 | | | | | |
| 69 | | | | | |
| 70 | | | | | |
| 71 | Less: | Wheeling | (4,281) | (4,050) | (231) |
| 72 | | Power Purchases | (71,519) | (71,964) | 446 |
| 73 | | Water Fees | (9,047) | (9,256) | 209 |
| 74 | O & M Expense per Financial Statements | | **42,299** | **36,619** | **5,680** |
| 75 | | | | | |
| 76 | Add: | Capitalized Overhead | **10,777** | **9,529** | **1,248** |
| 77 | | | | | |
| 78 | **Gross O&M** | | **53,076** | **46,148** | **6,928** |

*Note: Minor differences due to rounding.*

## SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | | ($000s) | |
|---|---|---|---|---|
| 1 | Amortization of Prior Year Incentives | | | |
| 2 | | Amortization of 2009 Incentives | (1,090) | |
| 3 | | Amortization of 2010 Incentives | (1,681) | |
| 4 | | | | |
| 5 | | Total Amortization of Prior Year Incentives | | (2,770) |
| 6 | | | | |
| 7 | Current Year Preliminary Flow Through Adjustments | | | |
| 8 | | Interest Expense | 835 | |
| 9 | | Transmission Pole Rental Revenue | 59 | |
| 10 | | Fibre Leasing Revenue | 175 | |
| 11 | | Water Fees Rate Reduction | 223 | |
| 12 | | Celgar Tariff Difference | 1,990 | |
| 13 | | Total 2011 Flow Through Adjustments | 3,281 | |
| 14 | | | | |
| 15 | Current Year Preliminary ROE Incentive Adjustments | | | |
| 16 | | Preliminary ROE Incentive | 2,559 | |
| 17 | | | | |
| 18 | | | | |
| 19 | | Total Regulatory Incentive Adjustments | | 5,840 |
| 20 | | | | |
| 21 | | | | |
| 22 | Current Year True-up to Actual [1] | | | 1,047 |
| 23 | | | | |
| 24 | | | | |
| 25 | Incentive Adjustments per Income Statement | | | 4,116 |

[1] *A provision for true-up of incentives of $1,047,000 was recorded in 2011, post 2012 - 2013 Revenue Requirements, Evidentiary Update Filing. This true-up from final incentives for 2010 will flow through to 2014 Revenue Requirements.*

*Note: Minor differences due to rounding.*

## SUMMARY OF PRELIMINARY INCENTIVE ADJUSTMENTS TO INCOME STATEMENT, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2011

| | 2011 Flow Through Adjustments | Approved | Forecast | Variance | Income Tax Shield | After Tax Amount | Customer Share | Flow Through Adjustment |
|---|---|---|---|---|---|---|---|---|
| | | | | | ($000s) | | | |
| 1 | Interest Expense | 40,505 | 39,369 | 1,136 | 301 | 835 | 100% | 835 |
| 2 | Transmission Pole Rental Revenue | - | - | 80 | 21 | 59 | 100% | 59 |
| 3 | Fibre Leasing Revenue | - | - | 237 | 63 | 175 | 100% | 175 |
| 4 | Water Fees Rate Reduction | - | - | 303 | 80 | 223 | 100% | 223 |
| 5 | Celgar Tariff Difference | - | - | 2,708 | 718 | 1,990 | 100% | 1,990 |
| 6 | Flow-Through Adjustment | | | | | | | 3,281 |

| | 2011 ROE Incentive Adjustment | | Before Incentive | | | | After Incentive |
|---|---|---|---|---|---|---|---|
| | | Approved | Forecast | Variance | Customer Share | ROE Incentive Adjustment | Forecast |
| | | | ($000s) | | | | ($000s) |
| 7 | Net Income for ROE Incentive | 43,292 | 48,410 | (5,118) | 50% | (2,559) | 45,851 |
| 8 | Common Equity | 437,296 | 434,751 | | | | 433,472 |
| 9 | Allowed ROE | 9.90% | 11.14% | 1.24% | 50% | | 10.58% |

*Note: Minor differences due to rounding.*

# SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Normalized 2010 | Decision 2011 | Actual 2011 | Normalized 2011 | Change from Decision |
|---|---|---|---|---|---|---|
| | | | | ($000s) | | |
| 1 | UTILITY INCOME BEFORE TAX | 79,650 | 90,531 | 94,577 | 94,446 | 3,915 |
| 2 | Deduct: | | | | | |
| 3 | Interest Expense | 35,138 | 40,505 | 38,893 | 38,893 | (1,613) |
| 4 | ACCOUNTING INCOME | 44,512 | 50,025 | 55,684 | 55,553 | 5,528 |
| 5 | | | | | | |
| 6 | Deductions: | | | | | |
| 7 | Capital Cost Allowance | 52,849 | 56,903 | 57,441 | 57,441 | 538 |
| 8 | Capitalized Overhead | 9,529 | 10,777 | 10,777 | 10,777 | - |
| 9 | Incentive & Revenue Deferrals | 629 | 2,770 | (4,116) | (4,116) | (6,886) |
| 10 | Financing Fees | 597 | 619 | 587 | 587 | (33) |
| 11 | All Other (net effect) | 3,020 | (217) | 879 | 879 | 1,096 |
| 12 | | 66,624 | 70,852 | 65,568 | 65,568 | (5,284) |
| 13 | | | | | | |
| 14 | Additions: | | | | | |
| 15 | Amortization of Deferred Charges | 3,695 | 3,297 | 3,236 | 3,236 | (61) |
| 16 | Depreciation | 38,075 | 42,201 | 42,113 | 42,113 | (88) |
| 17 | | 41,770 | 45,498 | 45,349 | 45,349 | (149) |
| 18 | | | | | | |
| 19 | TAXABLE INCOME | 19,658 | 24,671 | 35,465 | 35,334 | 10,663 |
| 20 | | | | | | |
| 21 | Tax Rate | 28.50% | 26.50% | 26.50% | 26.50% | 0.00% |
| 22 | | | | | | |
| 23 | Taxes | 5,603 | 6,538 | 9,398 | 9,363 | 2,826 |
| 24 | Investment Tax Credit | - | - | (39) | (39) | (39) |
| 25 | Tax Payable | 5,603 | 6,538 | 9,360 | 9,325 | 2,787 |
| 26 | Prior Years' Overprovisions/(Underprovisions) | (738) | - | (127) | (127) | (127) |
| 27 | Deferred Charges Tax Effect | 184 | 195 | 184 | 184 | (11) |
| 28 | | | | | | |
| 29 | REGULATORY TAX PROVISION | 5,048 | 6,733 | 9,417 | 9,382 | 2,649 |

*Note: Minor differences due to rounding.*

## SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | | Normalized 2010 | Decision 2011 | Actual 2011 | Normalized 2011 | Change From Decision |
|---|---|---|---|---|---|---|---|
| | | | | | ($000s) | | |
| 1 | Share Capital | | 170,122 | 213,000 | 180,122 | 180,122 | (32,878) |
| 2 | Retained Earnings | | 213,403 | 220,420 | 238,424 | 238,424 | 18,004 |
| 3 | | | | | | | |
| 4 | COMMON EQUITY - OPENING BALANCE | | 383,525 | 433,420 | 418,546 | 418,546 | (14,874) |
| 5 | | | | | | | |
| 6 | Less: | Common Dividends | (15,000) | (16,000) | (16,000) | (16,000) | - |
| 7 | Add: | Net Income | 39,464 | 43,292 | 46,268 | 46,171 | 2,879 |
| 8 | | Share Adjustment | - | | - | - | - |
| 9 | | Shares Issued | 10,000 | 10,000 | - | - | (10,000) |
| 10 | | | | | | | |
| 11 | COMMON EQUITY - CLOSING BALANCE | | 417,989 | 470,712 | 448,813 | 448,717 | (21,995) |
| 12 | | | | | | | |
| 13 | SIMPLE AVERAGE | | 400,757 | 452,066 | 433,680 | 433,631 | (18,435) |
| 14 | | | | | | | |
| 15 | Adjustment for Shares Issued | | (4,973) | (3,685) | - | - | 3,685 |
| 16 | Deemed Equity Adjustment | | - | (11,085) | - | - | 11,085 |
| 17 | | | | | | | |
| 18 | COMMON EQUITY - AVERAGE | | 395,785 | 437,296 | 433,680 | 433,631 | (3,665) |

*Note: Minor differences due to rounding.*

**SCHEDULE 5 – RETURN ON CAPITAL**

FOR THE YEAR ENDING DECEMBER 31, 2011

| | | Normalized 2010 | Decision 2011 | Actual 2011 | Normalized 2011 | Change From Decision |
|---|---|---|---|---|---|---|
| | | | | ($000s) | | |
| 1 | Secured and Senior Unsecured Debt | 552,603 | 650,000 | 640,000 | 640,000 | (10,000) |
| 2 | Proportion | 58.42% | 59.46% | 60.04% | 60.04% | 0.59% |
| 3 | Embedded Cost | 6.18% | 6.04% | 6.04% | 6.04% | 0.00% |
| 4 | Cost Component | 3.61% | 3.59% | 3.63% | 3.63% | 0.03% |
| 5 | Return | 34,174 | 39,275 | 38,664 | 38,664 | (610) |
| 6 | | | | | | |
| 7 | Short Term Debt | (3,686) | 5,945 | (7,787) | (7,787) | (13,732) |
| 8 | Proportion | -0.39% | 0.54% | -0.73% | -0.73% | -1.27% |
| 9 | Embedded Cost | -26.15% | 20.71% | -2.93% | -2.93% | -23.64% |
| 10 | Cost Component | 0.10% | 0.11% | 0.02% | 0.02% | -0.09% |
| 11 | Return (including fees) | 964 | 1,231 | 228 | 228 | (1,003) |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | Common Equity | 395,785 | 437,296 | 433,680 | 433,631 | (3,665) |
| 15 | Proportion | 41.90% | 40.00% | 40.69% | 40.68% | 0.68% |
| 16 | Embedded Cost | 9.97% | 9.90% | 10.67% | 10.65% | 0.75% |
| 17 | Cost Component | 4.18% | 3.96% | 4.34% | 4.33% | 0.37% |
| 18 | Return | 39,464 | 43,292 | 46,268 | 46,171 | 2,879 |
| 19 | | | | | | |
| 20 | TOTAL CAPITALIZATION | 944,701 | 1,093,241 | 1,065,892 | 1,065,844 | (27,397) |
| 21 | RATE BASE | 945,637 | 1,093,241 | 1,065,892 | 1,065,892 | (27,349) |
| 22 | | | | | | |
| 23 | Earned Return | 74,602 | 83,798 | 85,160 | 85,064 | 1,266 |
| 24 | | | | | | |
| 25 | RETURN ON CAPITAL | 7.90% | 7.67% | 7.99% | 7.98% | 0.32% |
| 26 | RETURN ON RATE BASE | 7.89% | 7.67% | 7.99% | 7.98% | 0.32% |

*Note: Minor differences due to rounding.*

# EXECUTIVE SUMMARY
# DIRECTORS, OFFICERS AND SHAREHOLDERS
AS AT DECEMBER 31, 2011

## DIRECTORS

| NAME AND RESIDENCE | PRINCIPAL OCCUPATION | ROLE ON BOARD |
|---|---|---|
| Harold G. Calla<br>British Columbia, Canada | Chair of the First Nation Financial Management Board | Audit and Risk Committee |
| Beth D. Campbell<br>British Columbia, Canada | President, Best in the West Motor Inn Ltd. | Governance Committee |
| Brenda Eaton<br>British Columbia, Canada | Board Chair, BC Housing Management Commission. | Audit and Risk Committee |
| Ida J. Goodreau<br>British Columbia, Canada | Corporate Director; additionally Adjunct Professor, Sauder School of Business, UBC | Governance Committee |
| H. Stanley Marshall<br>Newfoundland and Labrador, Canada | President & Chief Executive Officer of Fortis Inc. | Chair of the Board<br>Governance Committee |
| Roger M. Mayer<br>British Columbia, Canada | Vice Chair of the BC Agricultural Land Commission | Audit and Risk Committee |
| Harry McWatters<br>British Columbia, Canada | President, Vintage Consulting Group | Governance Committee |
| Barry V. Perry<br>Newfoundland and Labrador, Canada | Vice President, Finance and Chief Financial Officer of Fortis Inc. | Audit and Risk Committee |
| Linda S. Petch<br>British Columbia, Canada | Principal, Linda S. Petch Governance Services | Governance Committee |
| David R. Podmore<br>British Columbia, Canada | Chairman and Chief Executive Officer, Concert Properties Ltd.. | Audit and Risk Committee |
| Karl W. Smith<br>Alberta, Canada | President & CEO of FortisAlberta Inc. | Governance Committee |
| John C. Walker<br>British Columbia, Canada | President & CEO of FortisBC Inc. and additionally President & CEO of FortisBC Energy Inc. and FortisBC Holdings Inc. | |

## DIRECTORS, OFFICERS AND SHAREHOLDERS, cont'd

AS AT DECEMBER 31, 2011

### OFFICERS

| | | |
|---|---|---|
| John C. Walker | FortisBC Inc.<br>Suite 100 – 1975 Springfield Road<br>Kelowna, BC V1Y 7V7 | President and Chief Executive Officer |
| Michael A. Mulcahy | FortisBC Inc.<br>Suite 100 – 1975 Springfield Road<br>Kelowna, BC V1Y 7V7 | Executive Vice President, Human Resources, Customer & Corporate Services |
| Dwain A. Bell | FortisBC Inc.<br>10th Floor – 1111 West Georgia Street<br>Vancouver, BC V6E 4M3 | Vice President, Operations |
| David C. Bennett | FortisBC Inc.<br>Suite 100 – 1975 Springfield Road<br>Kelowna, BC V1Y 7V7 | Vice President, General Counsel and Corporate Secretary |
| Roger A. Dall'Antonia | FortisBC Inc.<br>10th Floor – 1111 West Georgia Street<br>Vancouver, BC V6E 4M3 | Vice President, Strategic Planning, Corporate Development & Regulatory Affairs |
| Cynthia Des Brisay | FortisBC Inc.<br>10th Floor – 1111 West Georgia Street<br>Vancouver, BC V6E 4M3 | Vice President, Energy Supply & Resource Development |
| Michele I. Leeners | FortisBC Inc.<br>Suite 100 – 1975 Springfield Road<br>Kelowna, BC V1Y 7V7 | Vice-President, Finance & Chief Financial Officer |
| Thomas A. Loski | FortisBC Inc.<br>4370 Still Creek Drive<br>Burnaby, BC V5C 6G9 | Vice President, Customer Service |
| Doyle Sam | FortisBC Inc.<br>Suite 100 – 1975 Springfield Road<br>Kelowna, BC V1Y 7V7 | Vice President, Engineering & Generation |
| Robert M. Samels | FortisBC Inc.<br>10th Floor – 1111 West Georgia Street<br>Vancouver, BC V6E 4M3 | Vice President, Business Planning |
| Douglas L. Stout | FortisBC Inc.<br>16705 Fraser Highway<br>Surrey, BC V3S 2X7 | Vice President, Energy Solutions & External Relations |

### SHAREHOLDERS

| | |
|---|---|
| FortisBC Pacific Holdings Inc. | 100% Common stock |

## IMPORTANT CHANGES IN THE YEAR

## A. OPERATING

### Turbine Upgrades and Generating Facilities

The Corra Linn Unit 1 Upgrade and Life Extension (ULE) was completed in 2011 as the tenth of eleven units to undergo a "water to wire" refurbishment under the ULE program.

Corra Linn Unit 2, the final unit of the ULE program, was returned to service in December of 2011 with inspection, efficiency testing and project wrap-up to be completed in 2012.

### Okanagan Transmission Reinforcement (OTR) Project

The OTR project consists primarily of construction of the Bentley Terminal Station near Oliver as well as the construction of two 230 kV transmission lines from Oliver to Penticton. It is required to address capacity constraints in the Okanagan region. The project was approved by Commission Order C-5-08 in October of 2008 and construction began in July 2009 with a new 230 kV line (40 Line) between Vaseux and Oliver completed in November 2009. Construction of the new double-circuit 230 kV line (75/76 Line) was completed in October 2010 and the 76 Line circuit was energized in November 2010 to coincide with the installation of the new transformer at the RG Anderson Terminal. 75 Line was energized in March 2011 which coincided with the completion of all work at RG Anderson and Vaseux Terminals. The Bentley Terminal was completed and energized in March 2011. All FortisBC components were completed by September 2011. Upgrades to BC Hydro's 500kV Vaseux Terminal component has been re-scheduled for completion in October 2012.

### Distribution Substation Automation Program

The Distribution Substation Automation Program (approved in 2007 by BCUC Order C-11-07) consists of installing remote monitoring and control systems in distribution substations, with a focus on reducing operational costs, preventing power outages and restoring power more quickly when there is a failure, as well as improving the levels of employee and public safety. Stations completed in 2011 include Beaver Park, Glenmerry, Hedley, Osoyoos, Salmo, Sexsmith, Stoney Creek, Trout Creek and West Bench. The Data Historian software and hardware were implemented in 2010 with the Data Historian and hierarchal database completed in 2011. The project was substantially completed on schedule by the end of 2011. Minor remaining completion work for 2012 includes final commissioning at the Beaver Park and Glenmerry substations.

## B. CUSTOMER SERVICE

### Customer Communications

To further enhance the Company's communication with customers, FortisBC committed funds to informational ads in local papers and radio stations to remind customers of the importance of safety for our field staff to access the meter and metering equipment. FortisBC related information was also added to the messaging heard by customers while on hold with the Company's Trail Contact Centre.

The Company continued to promote its electronic billing option with 15.65 per cent of customers signed up for eBilling at the end of 2011, an increase from 11.15 per cent in 2010.

## C. ENERGY MANAGEMENT

In 2011, FortisBC electric customers saved 36.3 GWh through PowerSense energy efficiency programs, or 91 per cent of the 39.8 GWh plan figure. The nominal DSM expenditure was $5.9 million or 75 per cent of the approved plan of $7.8 million.

A summary table of plan versus actual energy savings by sector is shown below:

| 2011 Energy Savings by Sector (GWh) | Plan | Actual | % of Plan Achieved |
|---|---|---|---|
| Residential | 16.4 | 11.4 | 69% |
| Commercial | 13.9 | 24.2 | 173% |
| Industrial | 9.4 | 0.8 | 8% |
| **Total savings (GWh)** | **39.8** | **36.3** | **91%** |

Overall the total energy savings increased by 7.0 GWh in 2011, which was 24% greater than the 29.3 GWh achieved in 2010.

Some sector highlights for the year:

Key Residential program results fell short of plan, and results include:

- Heat Pump programs achieved savings of 2.3 GWh;
- Home Improvement program achieved savings of 3.7 GWh;
- Lighting program achieved savings of 3.3 GWh; and
- The Low Income program achieved savings of 1.4 GWh.

Results in the Commercial sector exceeded the plan, and key program results include:

- 20.6 GWh of savings in commercial Lighting, including FortisBC Lighting Installation Program (FLIP);
- New Building and Process Improvement (BIP) program recorded 1.4 GWh in savings; and
- Water Handling Infrastructure program totaled 2.2 GW.h.

Results in the Industrial sector fell short of plan[1]. Program results include:

- Industrial efficiency projects yielded savings of 0.8 GWh; and
- No savings were recorded in the Energy Management Information System (EMIS) program.

2011 was a year of significant budget and scope growth for PowerSense. Nominal incentive (rebate) rates doubled from $.05 to $.10 per annual kWh saved for most programs and the number of programs available to customers – from residential to commercial – nearly doubled as well.

[1] 7.2 GWh of anticipated energy savings for the Zellstoff Celgar pulp mill project were not realized due to regulatory proceedings that had the potential to affect the treatment of demand-side measures

## D. REGULATORY

**2012 – 2013 Revenue Requirements Application (RRA) and Review of 2012 Integrated System Plan (ISP)**

On June 30, 2011 FortisBC filed a two-year RRA, its first full cost of service revenue requirements filing since 2005. Included in the RRA is the Company's 2012 – 2013 Capital Expenditure Plan (CEP), which outlines capital projects and Demand Side Management expenditures

In its ISP, FortisBC outlines its long-term strategic direction in the areas of capital and resource planning and energy conservation. The ISP provides the long-term context for the RRA and CEP.

The Company responded to two rounds of Information Requests and held a 2011 Annual Review on November 22, 2011. A procedural conference, also held on November 22, 2011, established an oral public hearing process to complete the review of the application. The oral public hearing is scheduled to commence in early 2012.

## E. AUDIT

**Internal Audit**

FortisBC's Internal Audit department continued rotational testing of Internal Controls over Financial Reporting in various business processes during 2011. In addition, the following internal audits were performed:

- **Transfer Pricing and Code of Conduct Audit –** an annual audit of compliance with the Transfer Pricing and Code of Conduct policies.
- **Executive Expense Account Audit** – an audit of discretionary expenses incurred by the executive management team.
- **Directors' Liabilities Audit** – an audit to test the timely reporting and remittance of statutory remittances (Payroll withholdings, Workers' Compensation Board (WCB), Corporate Income Tax and Retail Sales Taxes.)
- **Disclosure Controls and Financial Reporting Process Audit** – an audit of internal controls over Disclosure Procedures and the Financial Close Process.
- **Fraud Risk Assessment** – an annual Entity Level Assessment of Fraud Risk
- **Information Technology (IT) General Controls Audit** – an audit of Internal Controls in IT operations.
- **Company Credit Cards and Expense Reports Audit** – Company-wide audit of compliance with Travel Policy and Credit Card Policy.

**E. AUDIT**, cont'd

### External Audit

In addition to its quarterly reviews and annual audit of the Financial Statements, Ernst & Young LLP performed the following:

- **IT General Controls Audit –** a test of automated and manual internal controls within Information Technology (computer systems) to substantiate the external auditors' opinion of Internal Controls over Financial Reporting within the organization.

## F. LEGAL PROCEEDINGS

### Vaseux Lake Fire

The Province of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a Writ and Statement of Claim against FortisBC dated August 2, 2005. The Province of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private land owners have filed separate Writs and Statements of Claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time, and accordingly no amount has been accrued in the financial statements.

### FortisBC Inc. v. Shaw Cablesystems Limited et al.

This matter relates to legal proceedings that FortisBC Inc. commenced against Shaw Cablesystems Limited, Shaw Communications Inc., and Shaw Business Solutions Inc. (Shaw) in the Supreme Court of British Columbia on October 1, 2009 relating to Shaw's facilities located on FortisBC's facilities.

Shaw also applied for an order by the Commission to allow Shaw to continue to use FortisBC's electric transmission facilities for Shaw's telecommunications facilities throughout the FortisBC service area, pursuant to section 70 of the Utilities Commission Act. This matter was fully settled and ended in 2011.

## COMPANY PROFILE

| | | Return on Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Allowed | Achieved | Normal | Bond Yield (1) | Common Equity | Rate Base ($000s) | Energy Sales (MW.h) | Temperature (% warm, HDD) | Direct Customers |
| 1 | 2002 | 9.53% | 8.24% | 8.32% | 5.68% | 46.73% | 382,503 | 2,791 | -3.1% | 92,804 |
| 2 | 2003 | 9.82% | 10.88% | 10.80% | 5.34% | 42.49% | 442,688 | 2,834 | 7.9% | 95,070 |
| 3 | 2004 | 9.55% | 10.70% | 11.04% | 5.14% | 43.02% | 498,974 | 2,874 | 5.5% | 97,317 |
| 4 | 2005 | 9.43% | 9.88% | 9.87% | 4.40% | 41.70% | 589,845 | 2,969 | 0.1% | 99,745 |
| 5 | 2006 | 9.20% | 9.94% | 10.05% | 4.28% | 40.21% | 671,138 | 3,040 | -5.7% | 102,413 |
| 6 | 2007 | 8.77% | 9.23% | 9.15% | 4.32% | 40.38% | 746,543 | 3,090 | 0.2% | 107,724 |
| 7 | 2008 | 9.02% | 9.28% | 9.16% | 4.05% | 41.66% | 802,566 | 3,087 | 9.8% | 109,719 |
| 8 | 2009 | 8.87% | 9.41% | 9.17% | 3.90% | 42.19% | 867,683 | 3,157 | 7.2% | 110,853 |
| 9 | 2010 | 9.90% | 9.65% | 9.97% | 3.73% | 41.97% | 945,637 | 3,046 | -5.4% | 112,250 |
| 10 | 2011 | 9.90% | 10.67% | 10.65% | 3.29% | 40.69% | 1,065,892 | 3,143 | 1.4% | 113,261 |

(1) Canada long-term benchmark bonds monthly average

*Note: Minor differences due to rounding.*

## TEN-YEAR SUMMARY

| | | 2011 | 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | DISTRIBUTION OF ELECTRICITY (GWh) | | | | | | | | | | |
| 2 | Sales | | | | | | | | | | |
| 3 | Residential | 1,260 | 1,224 | 1,293 | 1,221 | 1,160 | 1,091 | 1,070 | 1,020 | 1,005 | 997 |
| 4 | Wholesale | 896 | 881 | 928 | 892 | 636 | 948 | 916 | 931 | 915 | 873 |
| 5 | Industrial | 282 | 234 | 203 | 252 | 352 | 344 | 357 | 345 | 338 | 347 |
| 6 | Commercial & Other | 705 | 707 | 733 | 722 | 943 | 657 | 624 | 578 | 577 | 574 |
| 7 | | 3,143 | 3,046 | 3,157 | 3,087 | 3,090 | 3,040 | 2,969 | 2,874 | 2,834 | 2,791 |
| 8 | | | | | | | | | | | |
| 9 | EARNINGS ($000s) | | | | | | | | | | |
| 10 | Operating Revenue | 284,595 | 253,244 | 243,759 | 225,944 | 215,155 | 208,515 | 187,462 | 179,353 | 168,205 | 154,355 |
| 11 | | | | | | | | | | | |
| 12 | Operating Expenses | 42,299 | 36,619 | 36,702 | 35,663 | 34,165 | 32,337 | 37,680 | 36,042 | 30,061 | 32,094 |
| 13 | Power Purchases | 71,518 | 71,964 | 70,776 | 66,010 | 66,629 | 67,576 | 60,404 | 59,014 | 58,436 | 52,261 |
| 14 | Wheeling | 4,281 | 4,050 | 4,003 | 3,655 | 3,471 | 3,840 | 3,956 | 3,817 | 3,727 | 3,996 |
| 15 | Property & Capital Taxes | 13,408 | 12,238 | 11,573 | 11,036 | 10,642 | 10,275 | 9,540 | 10,047 | 9,115 | 9,593 |
| 16 | Water Fees | 9,047 | 9,256 | 8,656 | 7,878 | 7,918 | 8,371 | 7,679 | 7,399 | 7,370 | 7,120 |
| 17 | Depreciation | 45,349 | 41,771 | 37,376 | 34,016 | 30,949 | 26,746 | 18,840 | 16,817 | 14,637 | 14,344 |
| 18 | | 185,902 | 175,897 | 169,086 | 158,258 | 153,774 | 149,144 | 138,098 | 133,135 | 123,345 | 119,407 |
| 19 | | | | | | | | | | | |
| 20 | Earnings from Operations | 98,693 | 77,347 | 74,672 | 67,686 | 61,380 | 59,371 | 49,364 | 46,218 | 44,860 | 34,948 |
| 21 | | | | | | | | | | | |
| 22 | AFUDC | - | - | - | - | - | (2,360) | (3,335) | (2,434) | (3,370) | (2,451) |
| 23 | Interest Expense | 38,893 | 35,138 | 33,411 | 30,163 | 28,731 | 26,112 | 22,389 | 19,033 | 19,120 | 15,200 |
| 24 | Income Tax | 9,417 | 4,544 | 4,749 | 5,869 | 5,898 | 6,504 | 7,148 | 8,333 | 7,578 | 5,892 |
| 25 | Incentive Adjustment | 4,116 | (629) | 2,014 | 654 | (1,391) | 2,431 | (1,219) | (2,300) | 1,281 | 1,676 |
| 26 | Net Earnings | 46,268 | 38,294 | 34,499 | 31,001 | 28,143 | 26,684 | 24,380 | 23,585 | 20,250 | 14,630 |
| 28 | | | | | | | | | | | |
| 29 | Return on Common Equity | 10.67% | 9.65% | 9.41% | 9.28% | 9.23% | 9.94% | 9.88% | 10.70% | 10.88% | 8.24% |

*Note: Minor differences due to rounding.*

## DECLARATIONS

1. UNIFORM SYSTEM OF ACCOUNTS

In my opinion, FortisBC Inc. classifies certain expenditures based on the Uniform System of Accounts as set out by the British Columbia Utilities Commission, with the exception of certain Operating and Maintenance accounts, which are classified according to FortisBC's Chart of Accounts. This variance to Commission Order G-28-80 was approved via Commission Letter L-34-99 dated July 6, 1999.

2. COMPLIANCE WITH COMMISSION'S FINANCIAL DIRECTIVES

In my opinion, FortisBC complies with the British Columbia Utilities Commission's financial directives contained in its Orders to FortisBC.

*Signed by*

ORIGINAL SIGNED BY
Charles P. Lee, C.G.A.
Controller

## OFFICER'S DECLARATION

I, Michele Leeners, do hereby certify:

1. That I am Vice-President, Finance and Chief Financial Officer with FortisBC Inc. with Head Office at Suite 100, 1975 Springfield Road, Kelowna, British Columbia;

2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 of the Utilities Commission Act.

*Signed by*

ORIGINAL SIGNED BY
Michele Leeners, C.A.
Vice President, Finance and
Chief Financial Officer

Any inquiries regarding this report should be directed to:

Joyce Martin
Manager, Regulatory Affairs
FortisBC Inc.
Suite 100, 1975 Springfield Rd.
Kelowna, BC V1Y 7V7

# APPENDIX A
# RECONCILIATION OF FINANCIAL STATEMENTS

## STATEMENT OF EARNINGS, CORPORATE AND REGULATORY
YEAR ENDED DECEMBER 31, 2011

| | Corporate (external) | | Regulated |
|---|---|---|---|
| | | ($000s) | |
| REVENUE | | | |
| Sale of power | 279,408 | (2,318) | 277,090 |
| Other | 4,540 | 2,965 | 7,505 |
| | 283,949 | 646 | 284,595 |
| EXPENSES | | | |
| Operating and Maintenance | 43,542 | (1,243) | 42,299 |
| Power Purchases | 71,581 | (63) | 71,518 |
| Wheeling | 4,281 | - | 4,281 |
| Property taxes | 13,787 | (379) | 13,408 |
| Water fees | 9,163 | (116) | 9,047 |
| Depreciation & Amortization of Deferreds | 45,260 | 89 | 45,349 |
| | 187,614 | (1,712) | 185,902 |
| EARNINGS FROM OPERATIONS | 96,335 | 2,358 | 98,693 |
| INTEREST EXPENSE | | | |
| Long-term debt | 39,315 | (651) | 38,664 |
| Short-term debt | 453 | (225) | 228 |
| Amortization of deferred financing costs | 422 | (422) | - |
| Debt Component of AFUDC | (750) | 750 | - |
| | 39,440 | (548) | 38,893 |
| REGULATORY INCENTIVE ADJUSTMENTS | - | 4,116 | 4,116 |
| EARNINGS BEFORE INCOME TAXES | 56,895 | (1,210) | 55,685 |
| INCOME TAXES | 9,396 | 21 | 9,417 |
| **NET EARNINGS** | **47,498** | **(1,230)** | **46,268** |

*Note: Minor differences due to rounding.*

# RECONCILIATION OF STATEMENT OF EARNINGS

## CORPORATE TO REGULATORY

| | ($000s) |
|---|---|
| Sale of Power | 279,408 |
| Walden Power Partnership | (2,319) |
| Regulated | 277,090 |
| Other Revenue | 4,540 |
| Reclassify Incentive Adjustments | 4,116 |
| Reclassify Non-regulated Interest Inc | (5) |
| Reclass sale of surplus power | (63) |
| Non-Regulated Reclass of AFUDC Equity Component | (1,083) |
| Regulated | 7,505 |
| Operating and Maintenance Expense | 43,542 |
| Non Regulated | (475) |
| Walden Power Partnership | (768) |
| Regulated | 42,299 |
| Power Purchases | 71,581 |
| Reclass sale of surplus power | (63) |
| Regulated | 71,518 |
| Property Taxes | 13,787 |
| Walden Power Partnership | (378) |
| Regulated | 13,408 |
| Water Fees | 9,163 |
| Walden Power Partnership | (116) |
| Regulated | 9,047 |

| | ($000s) |
|---|---|
| Depreciation & Amortization of Deferreds | 45,260 |
| Warfield Garage Expansion (non-reg) | (14) |
| Walden Power Partnership | (319) |
| Reclass Amortization of Deferred Financing Costs | 422 |
| Regulated | 45,349 |
| Long Term Interest Expense | 39,315 |
| Reclass to Short Term Interest | (419) |
| Walden Power Partnership | (232) |
| Regulated | 38,664 |
| Short Term Interest Expense | 453 |
| Reclass from Long Term Interest | 419 |
| Reclass CWIP to Non-Regulated entity | (645) |
| Regulated | 228 |
| Amortization of Deferred Financing Costs | 422 |
| Reclass to Depreciation & Amortization | (422) |
| Regulated | - |
| AFUDC | (750) |
| Non-Regulated Reclass AFUDC - Debt Component | 750 |
| Regulated | - |
| Incentive Adjustments | |
| Amortization of Prior Year Incentives | (2,771) |
| Current Year Incentive Adjustments | 6,887 |
| Regulated | 4,116 |
| Income Tax Expense | 9,396 |
| Walden Power Partnership & Non-Reg. Affiliates | 21 |
| Regulated | 9,417 |

*Note: Minor differences due to rounding.*

# BALANCE SHEET, CORPORATE AND REGULATORY

AS AT DECEMBER 31, 2011

| | Corporate (external) | ($000s) | Regulated |
|---|---|---|---|
| ASSETS | | | |
| Plant and Equipment & Intangibles | 1,469,216 | 86,211 | 1,555,427 |
| Less accumulated depreciation | (333,483) | (24,209) | (357,692) |
| | 1,135,733 | 62,002 | 1,197,735 |
| Other Assets | 10,457 | 2,700 | 13,157 |
| Regulated Assets | 130,037 | (130,037) | - |
| Non-Rate Base Assets | - | 148,953 | 148,953 |
| | 140,494 | 21,616 | 162,110 |
| Goodwill | 1,209 | (1,209) | - |
| Current Assets | | | |
| Cash | 4 | (4) | - |
| Accounts receivable | 39,415 | (12,923) | 26,492 |
| Unbilled revenue | - | 15,086 | 15,086 |
| Prepaid expenses | 928 | (26) | 902 |
| Other assets | 505 | (505) | - |
| Inventory | 439 | - | 439 |
| Regulated assets | 4,893 | (4,893) | - |
| Future income taxes | 2,426 | (2,426) | - |
| | 48,610 | (5,691) | 42,919 |
| TOTAL ASSETS | **1,326,046** | **76,718** | **1,402,764** |
| CAPITAL AND LIABILITIES | | | |
| Capitalization | | | |
| Shareholder's Equity | | | |
| Common shares | 201,851 | (21,729) | 180,122 |
| Retained earnings | 263,314 | 5,377 | 268,691 |
| Total Shareholder's Equity | 465,165 | (16,352) | 448,813 |
| Long-Term Debt | | | |
| Secured debentures | 25,000 | 15,000 | 40,000 |
| Unsecured debentures | 600,000 | - | 600,000 |
| Debt issue costs | (5,584) | 5,584 | - |
| Other debt | 9,917 | (925) | 8,992 |
| Total Long-Term Debt | 629,333 | 19,659 | 648,992 |
| Contributions in Aid of Construction | - | 95,551 | 95,551 |
| Obligation Under Capital Lease (non-rate base) | 25,510 | 424 | 25,934 |
| Other Post-Retirement Benefit Liability (non-rate base) | 16,663 | - | 16,663 |
| Other Liability (non-rate base) | 3,460 | (2,359) | 1,101 |
| Asset Retirement Obligation (non-rate base) | 3,935 | - | 3,935 |
| Future income taxes (non-rate base) | 101,616 | (2,413) | 99,203 |
| Future income taxes | - | 418 | 418 |
| Regulated Liability Long Term | 751 | (751) | - |
| | 151,935 | (4,681) | 147,254 |
| Current Liabilities | | | |
| Accounts payable and accrued liabilities | 41,149 | 2,984 | 44,133 |
| Current portion of debt | 24,504 | (24,504) | - |
| Current portion of obligation under capital lease | 424 | (424) | - |
| Regulated liability | 7,267 | (7,267) | - |
| Income taxes payable | 4,638 | 352 | 4,990 |
| Accrued interest | - | 4,545 | 4,545 |
| Future income taxes | 1,631 | (1,631) | - |
| Bank loans | - | 8,486 | 8,486 |
| | 79,613 | (17,459) | 62,154 |
| TOTAL CAPITAL AND LIABILITIES | **1,326,046** | **76,718** | **1,402,764** |

*Note: Minor differences due to rounding.*

# RECONCILIATION OF BALANCE SHEET
## AS AT DECEMBER 31, 2011

| ASSETS | ($000s) |
|---|---|
| Plant and Equipment & Intangibles | 1,469,216 |
| Contributions in Aid of Construction | 142,279 |
| Non-Regulated Warfield Garage Expansion | (246) |
| Capital Lease Asset (non-rate base) | (28,087) |
| Walden Power Partnership | (23,699) |
| Asset Retirement Obligation (non-rate base) | (4,036) |
| Regulated | 1,555,427 |
| | |
| Accumulated Depreciation | (333,483) |
| Contributions in Aid of Construction Accum Amort | (46,728) |
| Capital Lease Accum Dep (non-rate base) | 7,768 |
| Non-Regulated Warfield Garage Expansion Acc Dep | 99 |
| Walden Power Partnership Accum Dep | 13,755 |
| Asset Ret. Obligation Accum Dep (non-rate base) | 897 |
| Regulated | (357,692) |
| | |
| Other Assets (Deferred Charges) | 10,457 |
| Reclass to Accounts Receivable | (1,942) |
| Reclass from Current Regulated Assets | 4,893 |
| Reclass from LT Regulated Assets | 4,542 |
| Reclass from Debt Issue Costs | 4,833 |
| Reclass from Other Liability | (2,359) |
| Reclass from Current Regulated Liability | (7,267) |
| Regulated (Deferred Charges) | 13,157 |
| | |
| Regulated Assets - Long-term | 130,037 |
| Reclass to Deferred Charges | (4,542) |
| Non-Rate Base Assets | (125,495) |
| Regulated | - |
| | |
| Non-Rate Base Assets | - |
| Other Post-Retirement Benefits | 16,663 |
| BTS Lease Costs | 5,614 |
| Trail Office Lease Costs | 1,101 |
| Future Income Tax | 99,203 |
| ARO Regulated Asset | 796 |
| Advanced Metering Infrastructure (AMI) Costs | 2,118 |
| Capital Lease Asset (non-rate base) | 28,087 |
| Capital Lease Accum Dep | (7,768) |
| Asset Retirement Obligation (non-rate base) | 4,036 |
| Asset Ret. Obligation Accum Dep (non-rate base) | (897) |
| Regulated | 148,953 |
| | |
| Goodwill | 1,209 |
| Non Regulated | (1,209) |
| Regulated | - |
| | |
| Cash | 4 |
| Walden Power Partnership | (4) |
| Regulated | - |
| | |
| Accounts Receivable | 39,415 |
| Reclass to Unbilled Revenue | (15,086) |
| Reclass from Deferred Charges | 1,942 |
| Reclass from Current Other Assets | 505 |
| Non-Regulated | (15) |
| Walden Power Partnership | (269) |
| Regulated | 26,492 |
| | |
| Unbilled Revenue | - |
| Reclass from Accounts Receivable | 15,086 |
| Regulated | 15,086 |
| | |
| Prepaid Expenses | 928 |
| Walden Power Partnership | (26) |
| Regulated | 902 |
| | |
| Future Income Taxes | 2,426 |
| Reclass to Long-term FIT Liability | (2,426) |
| Regulated | - |
| | |
| Other Assets | 505 |
| Reclass to Accounts Receivable | (505) |
| Regulated | - |
| | |
| Regulated Assets - Current | 4,893 |
| Reclass to Deferred Charges | (4,893) |
| Regulated | - |

| CAPITAL AND LIABILITIES | ($000s) |
|---|---|
| Retained Earnings | 263,314 |
| Non-Regulated | 5,377 |
| Regulated | 268,691 |
| | |
| Common Shares | 201,851 |
| Non-Regulated | (21,729) |
| Regulated | 180,122 |
| | |
| Secured Debentures | 25,000 |
| Reclass from Current Portion of Debt | 15,000 |
| Regulated | 40,000 |
| | |
| Debt Issue Costs | (5,584) |
| Reclass to Deferred Charges | 4,833 |
| Non-Regulated (effective interest method) | 751 |
| Regulated | - |
| | |
| Contributions in Aid of Construction | - |
| Reclass from Plant and Equipment | 142,279 |
| Reclass from Accumulated Depreciation | (46,728) |
| Regulated | 95,551 |
| | |
| Obligation Under Capital Lease (non-rate base) | 25,510 |
| Reclass from Current | 424 |
| Regulated | 25,934 |
| | |
| Other Debt | 9,917 |
| Walden Power Partnership | (925) |
| Regulated | 8,992 |
| | |
| Other Liability (non-rate base) | 3,460 |
| Reclass to Deferred Charges | (2,359) |
| Regulated | 1,101 |
| | |
| Future Income Taxes - Long-term (non-rate base) | 101,616 |
| Reclass from FIT Asset | (2,426) |
| Reclass from Current FIT Liability | 1,631 |
| Princeton Light & Power Regulated FIT Liability | (418) |
| Walden Power Partnership | (1,200) |
| Regulated | 99,203 |
| | |
| Future Income Taxes - Long-term | - |
| Princeton Light & Power Regulated FIT Liability | 418 |
| Regulated | 418 |
| | |
| Regulated Liability - Long-term | 751 |
| Non-Regulated (effective interest method) | (751) |
| Regulated | - |
| | |
| Accounts Payable and Accrued Liabilities | 41,149 |
| Reclass to Accrued Interest | (4,545) |
| Intercompany Accounts | 7,725 |
| Non-Regulated | (81) |
| Walden Power Partnership | (115) |
| Regulated | 44,133 |
| | |
| Current Portion of Debt | 24,504 |
| Reclass to Bank Loans | (8,486) |
| Reclass to Secured Debentures | (15,000) |
| Walden Power Partnership | (1,018) |
| Regulated | - |
| | |
| Current Portion of Obligation Under Capital Lease | 424 |
| Reclass to Long-term | (424) |
| Regulated | - |
| | |
| Regulated Liability - Current | 7,267 |
| Reclass to Deferred Charges | (7,267) |
| Regulated | - |
| | |
| Income Taxes Payable | 4,638 |
| Walden Power Partnership | (181) |
| Non-Regulated | 533 |
| Regulated | 4,990 |
| | |
| Accrued Interest | - |
| Reclass from Accounts Payable | 4,545 |
| Regulated | 4,545 |
| | |
| Future Income Taxes - Current | 1,631 |
| Reclass to Long-term FIT Liability | (1,631) |
| Regulated | - |
| | |
| Bank Loans | |
| Reclass from Current Portion of Debt | 8,486 |
| Regulated | 8,486 |

*Note: Minor differences due to rounding.*

# APPENDIX B
# INCOME TAX ASSESSMENT

Canada Revenue Agency  Agence du revenu du Canada

Surrey BC V3T 5E1



FORTISBC INC.
C/O IAN LORIMER
SUITE 100
1975 SPRINGFIELD ROAD
KELOWNA BC  V1Y 7V7

| | |
|---|---|
| Date of mailing | September 1, 2011 |
| Business Number | 10564 5642 RC0001 |
| Tax year-end | December 31, 2010 |

0001225

**CORPORATION NOTICE OF ASSESSMENT**

**RESULTS**

**Thank you for choosing to use our Corporation Internet Filing service.**

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

| | | |
|---|---|---|
| Result of this Assessment : | $ | 300,797.62 Cr |
| Amount refunded: | $ | 300,797.62 |
| Prior balance: | $ | 0.00 |
| | | ================= |
| Total balance: | $ | 0.00 |

We are sending you a cheque for $300,797.62 separately.

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

FORTISBC INC.



| | |
|---|---|
| Date of mailing | September 1, 2011 |
| Business Number | 10564 5642 RC0001 |
| Tax year-end | December 31, 2010 |

## CORPORATION NOTICE OF ASSESSMENT

### SUMMARY OF ASSESSMENT

| | $ Reported | | $ Assessed |
|---|---|---|---|
| **Federal Tax:** | | | |
| Part I | 2,470,720.00 | | 2,470,720.00 |
| Part I.3 | 0.00 | | 0.00 |
| Part II | 0.00 | | 0.00 |
| Part III.1 | 0.00 | | 0.00 |
| Part IV | 0.00 | | 0.00 |
| Part IV.1 | 0.00 | | 0.00 |
| Part VI | 0.00 | | 0.00 |
| Part VI.1 | 0.00 | | 0.00 |
| Part XIII.1 | 0.00 | | 0.00 |
| Part XIV | 0.00 | | 0.00 |
| **Total Federal Tax:** | | $ | 2,470,720.00 |
| **Net Provincial and Territorial Tax/Credit:** | | | |
| British Columbia | 1,413,754.00 | | 1,413,754.00 |
| **Total Net Provincial and Territorial Tax/Credit:** | | $ | 1,413,754.00 |
| Instalment(s) applied | | | 4,184,194.00 Cr |
| | Net balance: | $ | 299,720.00 Cr |
| **Interest:** | | | |
| Refund interest | | | 1,077.62 Cr |
| | Result of this assessment: | $ | 300,797.62 Cr |
| | Amount refunded: | $ | 300,797.62 |
| | Prior balance: | $ | 0.00 |
| | Total balance: | $ | 0.00 |

Linda Lizotte-MacPherson
Commissioner of Revenue

### EXPLANATION

We have provided a breakdown of the provincial and territorial tax and credit amounts.

| **Net British Columbia tax/credit consists of the following:** | | |
|---|---|---|
| British Columbia tax | $ | 1,441,254.00 |
| British Columbia political contribution tax credit | $ | 500.00 |
| British Columbia training tax credit | $ | 27,000.00 |

The amount of refund interest shown is taxable in the reporting period you receive it.

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide" or visit our Web site at www.cra.gc.ca.

Please visit www.cra.gc.ca/mybusinessaccount to access your business information online.

For information about online requests available to business clients, visit www.cra.gc.ca/requests-business. This service allows clients to electronically

**8. Historical (2002-2011) regulatory financial information by year:**

a. Capital Structure Components: common equity, preferred equity, long and short-term debt:

   i. Rate Base: opening, closing and mid-year,

   ii. Gross rate base if different from rate base that is subject to debt and equity return,

   iii. Income statement,

   iv. Summary and full detailed description of all deferral and reserve accounts:

b. Summary and full detailed description of all deferral and reserve accounts:

   i. Average percentage of delivery revenue covered by each account,

   ii. Average percentage of total revenue (including commodity/energy cost) covered by each amount

- See attached **electronic** documents for FBC's financial information

**9. Price to Book Value Ratios (including supporting calculations) since 2000 when the utility or its corporate parent has been acquired by another firm:**

- See section 9 of FEI's Minimum Filing Requirements

a. Interpretation of Price to Book Values Ratios

- The FBCU interprets the above Price to Book Value ratios as representative of transactions that occurred at a point in time and that there are factors other than the Price to Book Value ratios that are more relevant in determining a fair return.

- For discussion on the general relevance of Price to Book Value with respect to the Generic Cost of Capital proceeding, please see the Price to Book Value section in the expert testimony of Aaron Engen as part of FBCU's Other Filing Requirements submission.

- For interpretations of the Price to Book Value Ratios please see the expert testimony of Aaron Engen as part of FEU's Other Filing Requirements submission.

**10. Full explanation of any significant changes in accounting policy in the last 10 years.**

- See the attachment for discussion on FBC's accounting policy changes in the last 10 years

## FortisBC Inc.
## 10 Year Summary of Significant Changes in Accounting Policy included in Regulatory Applications (2002-2011)

**2002 Revenue Requirements Application**

| | | |
|---|---|---|
| Tab 2 | Section 3.2 – Extraordinary O&M Costs | Page 6 |

**3.2.1 – Head Office (Trail) Lease Payments**

Order G-41-94 (from 1994) granted FBC an accounting order to deviate from CGAAP and assume a cash basis in accounting for the stepped charges of the lease arrangement. Annual lease payments of $200K are included in base O&M costs, with amounts in excess of $200K included in Extraordinary O&M Costs.

**2003 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2004 Revenue Requirements Application**

| | | |
|---|---|---|
| Tab 8 | Section 1 – Request for Accounting Variance | Page 3 |

FortisBC has requested a variance from GAAP to record a 30-year lease obligation under the **Brilliant Terminal Station Facilities** Investment and Interconnection Agreement ("BTS FIIA") as an operating lease. Treatment as an operating lease benefits customers because the Net Present Value of Revenue Requirements is 20% lower than that for a capital lease.

**2005 Revenue Requirements Application**

| | | |
|---|---|---|
| G-52-05 | Section 2.3.5 – Other Post-Retirement Benefits | Page 30 |

GAAP requires that companies recognize and accrue future liabilities associated with providing certain benefits to retirees. Commission Order G-134-99 approved a variance from GAAP, enabling FortisBC to record post-retirement benefits (excluding pension benefits) on a cash basis. As a result, a future liability of approximately $4.4 million existed that had not been recognized in the financial statements. Pursuant to Order G-52-05, the Company will transition from using the cash basis to full accrual accounting for current liabilities over a period of three years beginning in 2006, and will continue to amortize the existing liability over a period of 15 years.

In 2005, the Company expensed the forecast cost using the cash basis plus one-third of the accrued liability. In 2006, the Company will include, in expense, the cost under the cash basis plus one-half of the accrued expense. In the final transition year of 2007, the Company will include the full accrued expense and be in full compliance with Section 3461 of the CICA Handbook. The portion of accounting expense that is not paid out in cash will be recorded in Deferred Charges and credited to Rate Base. The treatment will then be consistent with the accounting for Pension Benefits.

**2006 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2007 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2008 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2009 Revenue Requirements Application**

| Appendix 2 | Non-Rate Base Items | Page 6 |
|---|---|---|

This appendix outlined the request for specific approval of certain non-rate base deferrals. Based on existing BCUC regulatory orders, FortisBC has recorded or intends to record certain items to be recovered from customers in future rates in FortisBC's external financial statements, which are prepared in accordance with CGAAP. Currently, the presentation of these items differs under CGAAP when compared to regulatory reporting required by the BCUC. FortisBC requests inclusion of these differences as no-cost capital assets which are excluded from rate base customer rates in 2009. These items are as follows (although not stated, note that future income taxes were previously approved by BCUC Order G-37-84):

| | BCUC Order | Forecast 2009 ($000s) |
|---|---|---|
| Future Income Taxes | n/a | 82,168 |
| Brilliant Terminal Station Capital Lease | G-2-04 | 4,484 |
| Other Post-Retirement Benefits | G-52-05 | 4,083 |
| Trail Office Building Lease Costs | G-41-93 | 1,409 |

**2010 Revenue Requirements Application**

No significant changes in accounting policies included in the Application.

**2011 Revenue Requirements Application**

| | | |
|---|---|---|
| G-184-10 | 2011 RRA Decision – Executive Summary | Page 9 |

FortisBC documented its accounting position of capitalizing power purchase costs during downtime of generators when a ULE was taking place in Appendix E. The BCUC rejected this position and ordered ULE Power Purchase costs to be treated as incremental Power Purchase expense while the costs related to the upgrade is capital. This methodology was ordered to be adopted in future RRAs.

| | | |
|---|---|---|
| G-195-10 | 2011 Capital Expenditure Plan Decision – Executive Summary | Page 2 |

The BCUC rejected certain sustaining capital, such as the Transmission and Distribution Right-of-Way Reclamation Program, the Pine Beetle Kill Hazard Tree Removal Program, and the Hot Tap Connector Replacement Program. These rejected capital expenditures (total of $3.8 million) were considered to be more appropriately addressed as routine O&M and therefore were ordered to be included as part of operating costs.

## FortisBC Inc.
## 10 Year Summary of Significant Accounting Policy in External Financial Statements (2002-2011)

**December 31, 2002 FortisBC Inc. External Financial Statements**
No changes to accounting policy.

**December 31, 2003 FortisBC Inc. External Financial Statements**
No changes to accounting policy.

**December 31, 2004 FortisBC Inc. External Financial Statements**

**CHANGES TO ACCOUNTING POLICIES**
**Asset Retirement Obligations**
Effective January 1, 2004, the Company was required to retroactively adopt the recommendations of the Canadian Institute of Chartered Accountants ("CICA") on accounting for asset retirement obligations. The recommendations require total retirement costs to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. The Company recognizes asset retirement obligations in the period in which they are incurred if a reasonable estimate of fair value can be determined.

**Impairment of Long-lived Assets**
Effective January 1, 2004, the Company was required to retroactively adopt the recommendations of the CICA on accounting for asset impairment. The recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long-term prepaid expenses to be recognized in income when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

**December 31, 2005 FortisBC Inc. External Financial Statements**

**CHANGES TO ACCOUNTING POLICIES**
**Conditional Asset Retirement Obligations**
In December 2005, the CICA issued guidance which requires entities to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

**Accounting for Rate-Regulated Operations**
In May 2005, the CICA issued guidance which clarifies the required presentation and disclosures applicable to the netting of assets and liabilities for rate-regulated entities. As a result, the Company has had to include presentation of certain assets, liabilities, revenues and expenses as a result of regulation which differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate-regulation.

**<u>December 31, 2006 FortisBC Inc. External Financial Statements</u>**

**International Financial Reporting Standards ("IFRS")**

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies, such as FortisBC. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period to be adopted in 2011.

**<u>December 31, 2007 FortisBC Inc. External Financial Statements</u>**

**CHANGES TO ACCOUNTING POLICIES**

**Financial Instruments**

Effective January 1, 2007, FortisBC adopted the new financial instruments standards which require that all financial assets and liabilities be classified into categories based on their attributes. The categories determined for each of the financial assets and liabilities will determine their measurement, either at fair value or amortized cost, and how gains or losses are recognized. The standards also require all derivatives, and derivatives that are embedded in non-derivative contracts, to be recognized in the financial statements and measured at fair value.

**Comprehensive Income**

Effective January 1, 2007, FortisBC adopted the new comprehensive income standard which provides guidance for the reporting and presentation of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources. Examples of some items that would be included in other comprehensive income are changes in the fair value of available for sale assets and the effective portion of the changes in fair value of cash flow hedging instruments.

**Hedges**

Effective January 1, 2007, FortisBC adopted the new hedges standard which specifies the criteria under which hedge accounting may be applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures.

**<u>December 31, 2008 FortisBC Inc. External Financial Statements</u>**

**CHANGES TO ACCOUNTING POLICIES**

**Capital Disclosures**

Effective January 1, 2008, FortisBC adopted the new capital disclosures standard which requires additional information in the notes to the financial statements about the Company's capital and the manner in which it is managed, including qualitative and quantitative information regarding an entity's objectives, policies and processes for managing capital.

**Inventories**

Effective January 1, 2008, FortisBC adopted the new inventories standard which requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed.

**Financial Instruments Disclosures and Presentation**
Effective January 1, 2008, FortisBC adopted the new financial instruments standards which require disclosure on both qualitative and quantitative information to assist users of the financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed.

**<u>December 31, 2009 FortisBC Inc. External Financial Statements</u>**

**CHANGES TO ACCOUNTING POLICIES**
**Accounting for Rate-Regulated Activities**
Effective January 1, 2009, FortisBC adopted amended standards which eliminated certain exemptions in Canadian GAAP that provided relief to entities subject to rate-regulation. As a result, the Company is no longer able to apply exemptions relating to the recognition and measurement criteria for assets and liabilities arising from rate-regulation and instead needs to adopt accounting policies that are developed through the exercise of professional judgment and through consultation of other sources, including pronouncements issued in other jurisdictions. As a result, the Company applied US GAAP guidance on rate-regulation in order to recognize regulatory assets and liabilities.

**Income Taxes**
Effective January 1, 2009, FortisBC adopted amendments to the income tax standard, which required the prospective recognition of future income taxes and a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to customers. Under this method, future income tax assets and liabilities are recognized for temporary differences between the accounting and tax basis of existing assets and liabilities, the benefit of income tax reductions or tax losses available to be carried forward, and the effects of changes in tax laws and enacted or substantially enacted tax rates. Prior to January 1, 2009, the Company used the taxes payable method of accounting for income taxes on regulated earnings.

**Goodwill and Intangible Assets**
Effective January 1, 2009, FortisBC adopted the new goodwill and intangible asset standard which provides more comprehensive guidance on intangible assets, particularly for internally developed intangible assets. As a result of the new standard, FortisBC recognized software and land rights as intangible assets instead of property, plant and equipment.

**Credit Risk and the Fair Value of Financial Assets and Financial Liabilities**
Effective January 1, 2009, FortisBC adopted new guidance relating to evaluating credit risk which requires that the Company's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument.

**<u>December 31, 2010 FortisBC Inc. External Financial Statements</u>**
No changes to accounting policy.

**<u>December 31, 2011 FortisBC Inc. External Financial Statements (CGAAP)</u>**

## CHANGES TO ACCOUNTING POLICIES

### Business Combinations

Effective January 1, 2011, FortisBC adopted amendments to standards for business combinations which result in changes to the determination of the fair value of the assets and liabilities of the acquiree, which will result in a different calculation of goodwill with respect to acquisitions. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer.

## Appendix E

## EVIDENCE OF AARON ENGEN

**Opinion Evidence**

Prepared for

**FortisBC Energy Inc.**
**FortisBC Energy (Vancouver Island) Inc.**
**FortisBC Energy (Whistler) Inc.**
**FortisBC Inc.**

Prepared by


**Aaron M. Engen**
**BMO Capital Markets**


**August 3, 2012**

# Table of Contents


Table of Figures ........ 3

I) Introduction and Purpose ........ 4

II) Summary of Opinion Evidence ........ 7

III) Discussion and Analysis ........ 13

Equity Capital Market Conditions ........ 13

Debt Capital Market Conditions ........ 29

Government of Canada Bond Yields ........ 40

Financial Market Globalization ........ 42

Acquisition Price to Book / Rate Base to Book Value Ratios ........ 51

Market Required Returns & Investing Abroad ........ 64

Conclusion ........ 67

# Table of Figures

Figure 1 – S&P/TSX Composite Index 10-Year Performance .... 14
Figure 2 – Investor Confidence .... 17
Figure 3 – VIXC Index Performance .... 19
Figure 4 – VIX Index Performance .... 20
Figure 5 – S&P/TSX Volatility .... 21
Figure 6 – Canadian Equity Market Trading Volumes .... 23
Figure 7 – Quarterly Mutual Fund Flows .... 24
Figure 8 – S&P/TSX Composite Index Historical P/E Ratio .... 26
Figure 9 – Aggregate Cdn Quarterly Corporate B-Tax Earnings .... 27
Figure 10 – Earnings Yield – Gov’t Canada Bond Yield Spread .... 28
Figure 11 – Canadian Generic ‘A’ Spreads .... 32
Figure 12 – Cdn Utilities Group 30-Year Spreads .... 33
Figure 13 – Average Cdn Utilities Group 30-Year Spreads .... 34
Figure 14 – 10-Year Generic BBB Spreads Less A Spreads .... 35
Figure 15 – Aggregate Cdn Corporate Bond Issuance .... 36
Figure 16 – Cdn Corporate Bond Issuance by Rating .... 37
Figure 17 – Gov’t Canada Bond Yields .... 42
Figure 18 – Net Cdn Purchases of Foreign Stocks .... 43
Figure 19 – Net Foreign Purchases of Cdn Stocks .... 44
Figure 20 – PIAC Sponsor Organization Cdn, U.S. & Int’l Asset Mix .... 45
Figure 21 – Cdn Equity Issuance Jurisdictions .... 46

# I) Introduction and Purpose

**Background and Experience**

My name is Aaron Melvyn Engen. I am a Managing Director in BMO Capital Markets' Energy Infrastructure Group. My office is located at 900, 525 – 8th Avenue S.W., Calgary, Alberta. I joined the firm's investment and corporate banking group in 1999 and since that time I have advised corporate clients on merger and acquisition transactions and opportunities, equity and debt capital market offerings (including initial public offerings), bank debt, and corporate structuring issues. Select publicly disclosed advisory transactions in which I played a key role include:

- Pacific Northern Gas' sale of its 50% interest in Pacific Trails Pipeline to Apache Canada and EOG Canada
- Sale of Pacific Northern Gas to AltaGas Ltd.
- Sale of Husky Energy's interest in the Meridian Cogeneration Plant
- SemCAMS' strategic alternatives process
- TransAlta Power, L.P.'s sale to Cheung Kong Infrastructure
- Sale of TransCanada Corporation's interest in TransCanada Power, L.P. to EPCOR Utilities
- Calpine Power Income Fund's restructuring and subsequent sale to Harbinger Capital
- ATCO Midstream's strategic alternatives review
- Pembina Pipeline's acquisition of Western Facilities pipeline assets.

In addition, I have played a key role in numerous other financial advisory mandates in connection with transactions which were not consummated or where BMO Capital Markets advised an unsuccessful, potential buyer.

My recent capital markets transaction experience (where BMO Capital Markets played a sole or co-bookrunner role) includes the following select transactions:

| Issuer | Securities Offered |
|---|---|
| TransCanada | • $6.0 billion common equity<br>• $1.2 billion bonds |
| ATCO Group | • $925 million preferred shares<br>• $2.6 billion bonds |
| Enbridge Income Fund | • $200 million common equity (IPO)<br>• $500 million bonds |
| EPCOR Utilities | • $300 million bonds |
| Capital Power | • $230 million common equity (secondary) |
| Canadian Western Bank | • $105 million innovative tier 1 capital<br>• $200 million subordinated debt |
| Duke Energy Income Fund | • $108 million common equity |
| ARC Energy | • $200 million common equity (secondary) |
| Brighton Beach Power | • $400 million project financing |
| AltaLink | • $300 million bonds |

In addition, my capital markets transaction experience includes many other offerings where BMO Capital Markets played co-manager, rather than bookrunner, roles.

I have appeared as an expert witness before the National Energy Board, the Régie de l'énergie, and the Alberta Utilities Commission all in connection with cost of capital and capital structure matters. In conjunction with these issues, I have provided evidence regarding, among other things:

- historical, recent developments, and then current conditions in Canadian equity, debt, and bank debt capital markets;
- whether capital market or economic developments suggest there have been changes in the cost of capital in Canada;

- globalization of Canadian capital markets and what it meant in the context of the cost of capital in Canada and the extent to which non-Canadian comparables should be used in determining the cost of capital in Canada;
- investment community views of regulated asset returns on equity; and
- whether applicant requested returns on capital are fair and reasonable in the context of capital market conditions.

Prior to joining BMO Capital Markets, I was a partner at a major Canadian law firm, McCarthy Tétrault, where I practiced corporate and securities law, principally in the power and utilities sector.

I received a BA (Arts & Science) from the University of Lethbridge and an LLB and an MBA from the University of Alberta.

Through my role at BMO Capital Markets I have extensive capital markets, financial advisory and transactional experience in the energy infrastructure industry and a sound understanding of the industry's regulatory environment.

**Scope of Engagement**

I was asked by FortisBC Energy Inc. ("FEI"), on behalf of itself and FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc., and FortisBC Inc. (collectively, "FBCU") to provide capital market perspectives and opinion respecting select aspects of the final minimum filing requirements established by the British Columbia Utilities Commission (the "BCUC") in conjunction with these proceedings.

Specifically, FEI has asked that I provide capital markets evidence and opinion regarding:

- historical background, recent developments, current conditions, and various considerations in Canadian equity and debt capital markets;
- Government of Canada bond yields and market conditions;
- globalization of Canadian capital markets and what it means in the context of the cost of capital in Canada, the extent to which non-Canadian comparables should be considered when determining the cost of equity, and competition for capital;
- regulated asset acquisition price to book/rate base ratios and what they mean in the context of considering allowed returns on equity in Canada;
- market required returns and Canadian investment abroad and what they mean in the context of FEI's application; and
- whether FEI's requested return on equity of 10.5% on a deemed equity component of 40% is fair and reasonable in the context of Canadian financial market conditions.

## II) Summary of Opinion Evidence

**Current Capital Market Conditions**

*Equity Capital Market*

Canadian equity capital market conditions are currently reflected in:

- a very sensitive market tone in which the market reacts both quickly and aggressively as news emerges on economic, financial, and political issues;
- concern around the sustainability of the U.S. economic recovery;
- high levels of market volatility;
- market volatility is increasingly reflective of global economic and financial conditions – fears of a global economic slowdown, heightened by weak economic data out of the EU and the U.S., and the European sovereign debt crisis are negatively impacting the market;
- ongoing market volatility has investors adopting an increasingly defensive stance;

- mutual fund flows continue to move out of equity and into bond and income mutual funds; and
- a persistently higher "valuation bar" for equity as evidenced in very high Earnings/Bond Yield Spreads.

In addition, the S&P/TSX Composite Index has been on a downward trend for some months and its P/E ratio has been on a downward trend since early 2011.

Overall Canadian equity capital markets are challenging and volatile.

*Debt Capital Market*

Overall, the Canadian debt capital market is in good condition as 2012 issuance levels are line with 2011 and credit spreads tightened earlier this year after a period of widening in the latter part of 2011. That said, exogenous risks continue to impact debt capital market volatility in terms of both changes in credit spread levels and market access (ability to go to the market). Near-term risks include:

- European debt crisis
- Depth and duration of European recession
- Chinese growth slowing
- Recent mixed U.S. economic data
- U.S. elections in November

Although spreads have seen a strong recovery from their 2008-2009 financial crisis highs, they remain high relative to historic levels. Despite good current market conditions, the average Canadian utilities group[1] 30-year spreads are wider (177 bps) than they were at the time of the

[1] Comprised of FEI, Gaz Métro, TransCanada, Enbridge, Emera, and CU.

2009 Proceedings (163 bps). Investor appetite for risk in the debt capital market has generally diminished leading to an overall upward re-pricing of risk.

Benchmark Government of Canada bond rates are expected to rise over the coming years with little room for the increase to be offset by corporate spread tightening.

**Government of Canada Bond Yields**

Canadian bond yields have been in steady decline despite a bump up following the 2008-2009 market crash and have recently tumbled to record low levels, even lower than those seen during the height of the 2008-2009 market crash. Some of the factors pushing Government of Canada bond yields to currently very low levels are the very same factors which would tend to put upward pressure on the cost of equity.

Foreign capital inflows into the Canadian bond market are increasing, reflecting two broad motivations: safe-haven flows; and official diversification flows. Euro area-led concerns about the global economy and financial markets are prodding safe-haven flows while official diversification flows into the Canadian market stem from official investors diversifying away from U.S. Treasuries and U.S. dollars (and euros) to other "quality" destinations including Canada.

**September 2009-July 2012 Comparison**

The following table summarizes the current performance[2] of various financial market conditions

[2] As at July 4, 2012 or as otherwise noted herein.

relative to their performance at the time the BCUC heard evidence in the 2009 Return on Equity and Capital Structure Application (the "2009 Proceedings").

| Factor | Current Performance Relative to 2009 Proceedings |
|---|---|
| S&P/TSX Composite Index (Figure 1) | • Largely unchanged from levels during the 2009 hearing although on a downward trend rather than an upward trend (as was the case in 2009) |
| Investor Confidence (Figure 2) | • Substantially lower |
| VIXC (Figure 3) | • Slightly worse |
| VIX (Figure 4) | • Slightly improved |
| S&P/TSX Volatility (Figure 5) | • Significantly more volatile |
| Cdn Equity Market Trading Volumes (Figure 6) | • Lower volumes and coming during a period when trading volumes have been on a declining, rather than rising, trajectory as was the case in 2009 |
| S&P/TSX Historical P/E Ratio (Figure 8) | • Materially lower during a period where the ratio has been in decline – in sharp contrast to the rising ratio environment in 2009 |
| Quarterly Mutual Fund Flows (Figure 7) | • Increased equity funds outflows and much higher bond and income funds inflows |
| Cdn Generic "A" Spreads (Figure 11) | • Lower at the shorter end of the curve (5-year and 10-year) and same at the long end (30-year) |
| Average Cdn Utilities Group 30-Year Spreads (Figure 13) | • Materially wider |
| Aggregate Cdn Corporate Bond Issuance (Figure 15) | • Materially higher |
| Gov't Canada Bond Yields (Figure 17) | • Materially lower |

**Financial Market Globalization**

The globalization of Canadian financial markets is continuing. Canadians are significant investors in foreign equities because of the attractive alternatives foreign equities have offered relative to Canadian opportunities in the context of risk adjusted returns and portfolio diversification. They pursue investment opportunities and returns in the U.S. and foreign markets and increasingly so over the recent years. At the same time, Canadian issuers are raising substantial capital outside Canada. These facts support the views that:

- Canadian companies compete for capital with non-Canadian company investment opportunities; and
- expected returns on capital in other jurisdictions, particularly those in the U.S. regarding allowed returns on capital available to U.S. utilities, are relevant and should be taken into consideration when determining whether allowed returns on equity are fair and reasonable.

**Acquisition Price to Book / Rate Base to Book Value Ratios**

Nothing can be learned about the appropriateness of allowed returns on equity from recent Canadian merger and acquisition activity involving regulated assets. Regulated asset buyer expected returns on equity are supported by many factors other than allowed ROEs. Strategic factors, including geographic diversification, establishing a strategic foothold in a new market, and protecting owned-assets, affect regulated asset pricing. Other factors relate to transaction considerations which involve various financial and structuring issues, including, among others, expected rate base growth, required control premiums, expected increases in ROE, and implementation of performance-based regulation, which can serve to either reduce price to book ratios or increase expected ROEs resulting from the transaction.

Moreover, regulated asset acquisition pricing can be affected by the buyer’s ability to pay in the context of earnings per share accretion. Using strong share valuations to make smart, accretive acquisitions has nothing to do with whether the buyer is satisfied with the asset’s allowed ROEs.

Finally, aside from strategic and financial reasons which may be used to support strong regulated asset purchase prices, there are several reasons why acquisition transactions are not reflective of buyer expected ROEs including:

- outside observers cannot know what assumptions buyers used when reaching purchase price decisions and, consequently, what returns they expect;
- data from such transactions becomes “stale dated”;
- buyers make mistakes in reaching purchase price decisions; and
- transaction survivorship bias.

**Market Required Returns and Investing Abroad**

Private equity and Canadian pension funds seek returns on equity of 10% or more when investing in energy infrastructure assets. Pension fund investment activity in energy infrastructure outside Canada demonstrates the competition for capital which Canadian regulated energy infrastructure businesses face. Canadian regulated assets compete for capital with non-Canadian assets and, consequently, must offer competitive rates of return to attract capital on reasonable terms and conditions.

**Conclusion**

In light of Canadian current and prospective capital market conditions, market required returns on capital for energy infrastructure assets, and opportunities for investments of comparable risk at attractive rates of return in Canada, the U.S. and elsewhere, I believe FEI’s requested return on equity of 10.5% on a deemed equity component of 40% is consistent with current capital market conditions, would be viewed by the financial market as more representative of FEI’s true cost of capital, and would be fair and reasonable in the context of such conditions.

# III) Discussion and Analysis

## *Equity Capital Market Conditions*

Equity capital market conditions are a general indication of investor risk aversion/attraction and the cost of equity. Where market conditions are weak, uncertain, or volatile, one would generally expect to see lower investor confidence, heightened investor risk aversion and, accordingly, a higher cost of capital. Conversely, where market conditions are strong and less volatile, one would generally expect investors to be less risk averse (and more attracted to riskier investments) and, accordingly, a lower cost of capital.

**Recent Developments**

Canada's equity capital market began the last decade with a market crash in which the Canadian benchmark index plummeted from a high of 11,388 on September 1, 2000 to a low of 5,695 in on October 9, 2002, a fall of 50%. In early 2003 the S&P/TSX began the first of two bull runs of that decade and lasting roughly five years. During the period and despite several corrections of over 5%, the index rose from 5,695 on October 9, 2002 to a peak of 15,073 on June 18, 2008, representing a compound annual growth rate of roughly 18.6%. The very strong market performance was driven, in part, by stronger than average corporate earnings growth and lower than average interest rates and inflation.

Following the June 18, 2008 high, the market went on a violent and volatile free fall from its high to a low of 7,724 on November 20, 2008, a drop of almost 49% which erased five years of gains in a mere five months. The market fell further to 7,567 on March 9, 2009 bringing the total drop to 50%. During late 2008 and through 2009 the market registered record one-day declines, record two-day declines and the occasional one or two-day reversal of previous session losses.

Following its March 9, 2009 low, the S&P/TSX began a recovery reaching a post-crash high of 14,271 on April 5, 2011, representing an increase of approximately 88.6%. Since then the market experienced yet another reversal of fortunes falling roughly 16.5% from its April 2011 high to 11,914 on July 4, 2011. Perhaps unsurprisingly, this latest decline was accompanied by significant drops in short periods of time including, for example, the one-month 12.7% tumble from July 8 to August 8, 2011, a 10.7% drop between September 6 and October 4, 2011, and an 8.5% fall between May 1 and May 18, 2012.

Figure 1 illustrates the S&P/TSX's 10-year performance.

Figure 1 – S&P/TSX Composite Index 10-Year Performance
January 1, 2002 to July 4, 2012


Source: Bloomberg

At the time the BCUC heard evidence in the 2009 Proceedings, the index averaged approximately 11,200 in September 2009 with the result that at today's levels of approximately

11,500 during the month leading up to July 4, 2012, the index is largely unchanged. The difference between the two levels, though, is that in late 2009 the index was and had been on a bull run since March of that year. Conversely, current market levels are part of a decidedly bearish market tone as the index has been in a downward trend since April 5, 2011 as illustrated in Figure 1.

**Current Market Conditions**

Although the Canadian equity market has rebounded from its March 2009 lows, it currently lacks direction or "conviction" and has become more of an "event driven" market. In other words, the market is very sensitive and often reacts both quickly and aggressively as news emerges on economic, financial, and political issues. Such issues include, among others, developments in sovereign debt, monetary policy, global and domestic economic conditions, and global and domestic economic recovery prospects. At this point, major market concerns center around the European sovereign debt crisis, sustainability of the U.S. (and global) economic recovery, and slowing Chinese economic growth.

Although the U.S. economy is showing signs of recovery, the market remains concerned around the sustainability of the recovery. The U.S. economy expanded at a weak pace of 1.9% for the first three months of 2012. Experts are generally looking for the economy to grow at a modest 2.2% this year. As well, the U.S. job situation remains anemic. While there is job growth in absolute terms, unemployment remains high as many workers have taken themselves out of the job market.

Canadian stock market volatility is increasingly reflective of global economic and financial conditions. Generally, fears of a global economic slowdown, heightened by weak economic data out of the EU and the U.S., are negatively impacting the market. The market's crisis of confidence over the health of western economies has intensified as EU debt concerns have moved to the forefront and as a string of lackluster U.S. economic data have been released. EU concerns have been more recently impacted by Germany, the Eurozone's largest lender, whose economy is slowing at this critical time. U.S. concerns stem from the view that the country's recovery is proceeding slowly and poses an important risk to the global recovery. U.S. consumers are constrained by debt loads and high unemployment, the housing market and consumer confidence remain challenged, there has been recent weakness in business and manufacturing sentiment, and the S&P credit rating downgrade of the U.S. indicated a lack of trust in the country's ability to address its deficit.

In the face of ongoing market volatility (see Market Volatility below) investors have been adopting an increasingly defensive stance. They have been reducing positions in equity funds and moving into bond and income funds throughout 2011 and 2012 year-to-date. As investors return to the market, they are doing so through bond and income funds, as well as niche funds such as resources, rather than in straight equity with the result that equity fund flows remain deeply negative.[3] Investors are increasingly looking to yield for returns and less towards capital appreciation. The investor attraction to yield is driven by current low interest rates, an ongoing difficult/challenging/uncertain global economic environment, and increased risk aversion.

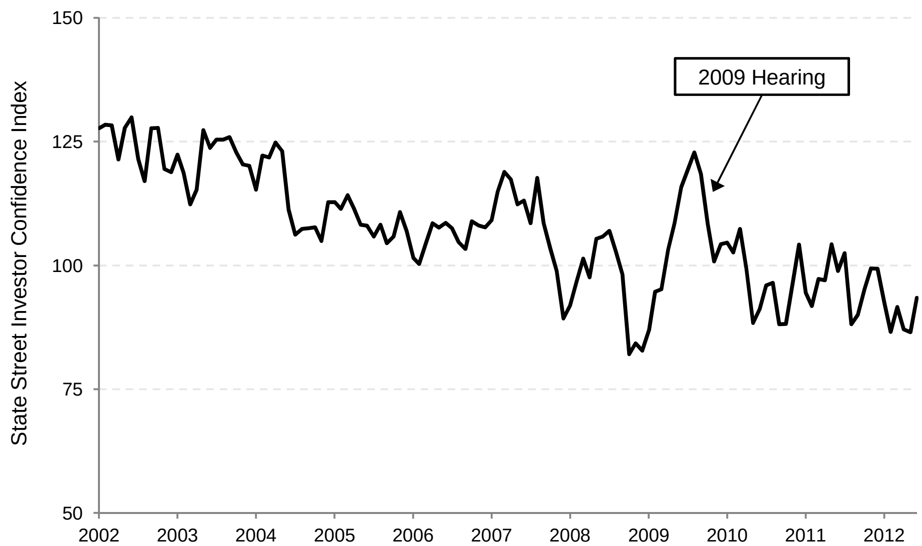
As measured by the State Street investor confidence index, investor confidence has been on a

[3] See Figure 7 – Quarterly Mutual Fund Flows.

general downward trend since mid-2009 and remains near recent 10-year lows. The State Street Investor Confidence Index “measures investor confidence or risk appetite quantitatively by analyzing the actual buying and selling patterns of institutional investors.”[4] Higher percentage allocations to equities mean higher risk appetite or confidence. The index includes global institutional activity, including that of Canadian institutional investors.

Given the globalization of Canada’s financial markets, the index, while not a reflection of Canadian investor activity alone, is a good proxy to consider. The index is widely used in the Canadian market as a representation of this country’s investor confidence levels. Figure 2 shows investor confidence from 2002 to present.

Figure 2 – Investor Confidence
January 2002 to June 2012




Source: Bloomberg

[4] http://statestreetglobalmarkets.com/research/investorconfidenceindex/index.html

At the time the BCUC heard evidence in the 2009 Proceedings, investor confidence stood at 118.4 for September 2009 while investor confidence level was substantially lower at 93.5 in June 2012.

**Market Volatility and Volumes**

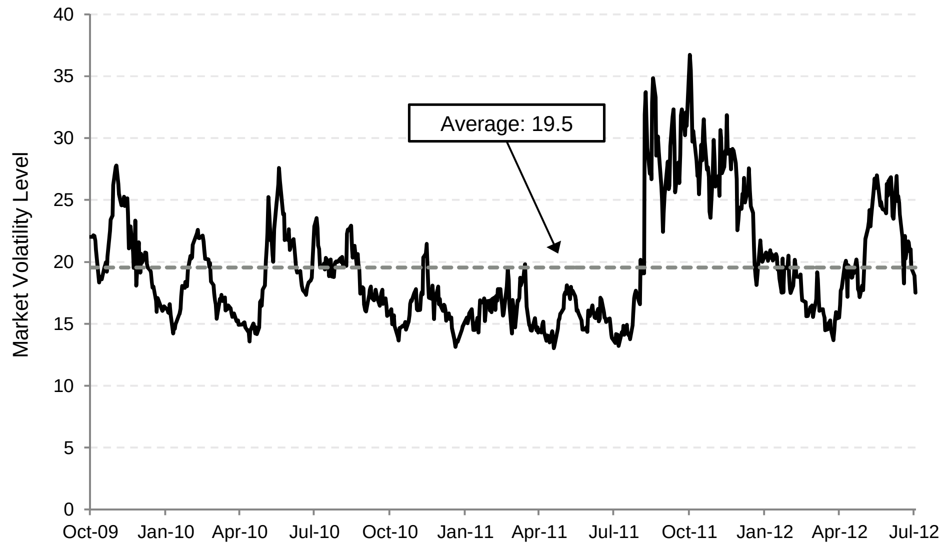
Market Volatility

Market volatility can be viewed from both market anticipation of near term volatility and actual or realized volatility. Expected volatility is illustrated in the VIXC which reflects the market's expectation of how relatively volatile the stock market will be over the upcoming month. The VIXC is an implied volatility index and is an indicator of investor sentiment for the Canadian equity market. Higher index values reflect higher anticipated risk of market turmoil. As a result, a rising index reflects heightened investor fears for the following month. As a forward looking measurement, the VIXC does not measure actual or realized market volatility.

Figure 3 shows VIXC performance since October 2009.[5] Until late July 2011 the VIXC generally stayed in a band of between 15 and 20 with a few periods of increased expected volatility in late 2009/early 2010. After that, the VIXC made a huge leap upwards reaching levels of 35 and higher during the latter half of 2011 and then falling to more average levels by early 2012. Levels recently peaked again at over 25 and currently stand at the almost two-year average of 19.5.

[5] The Montréal Exchange established its VIXC index in October 2010. Bloomberg provides back data on the index to 2009. The exchange's MVX, established in December 2002 and terminated in October 2010, is not comparable with the new index.

Figure 3 – VIXC Index Performance
October 1, 2009 to July 4, 2012



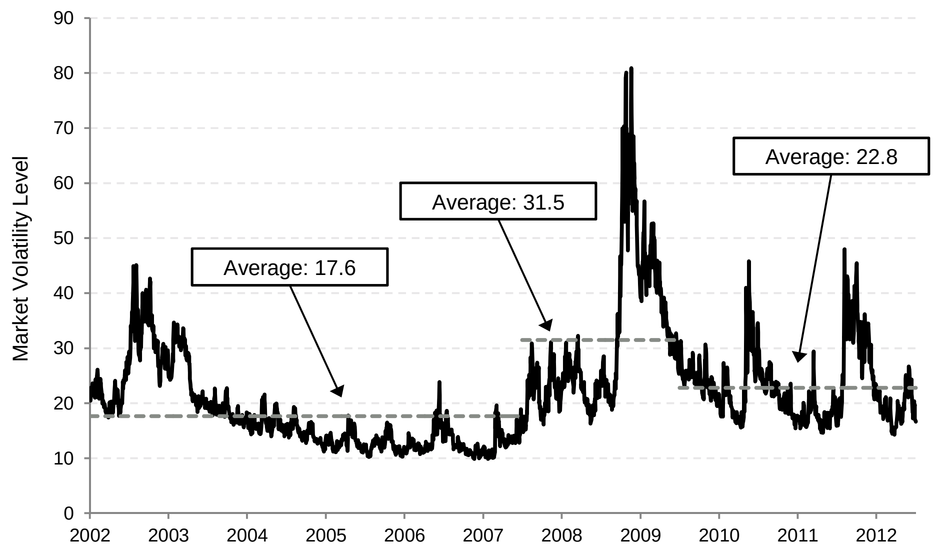

Source: Bloomberg

Shortly after the BCUC heard evidence in the 2009 Proceedings, the VIXC averaged 21.2 in October 2009. During the month ending July 4, 2012, the VIXC was at the slightly worse level of 22.39.

As a new index performance measure the VIXC only has a very short period of data. As an alternative, one can consider the VIX which is a key measure of market expectations of near-term volatility conveyed by S&P 500 stock index option price. Like the VIXC, the VIX is a measure of the market's expectation of stock market volatility over the forward 30 day period. The VIX is widely considered in the investment community as a barometer of market volatility and investor sentiment – including Canadian investor sentiment. It is often referred to as a fear index or a fear gauge.

The VIX averaged 17.6 during the period leading up to the 2008-2009 market crash, rising dramatically upward during the market crash to average 31.5 with peaks above 80 indicating highly elevated market fears and expectations of very high levels of market volatility. Since July 2009 the index averaged 22.8 with 2011 highs of almost 50. Recent market expectations of forward volatility are closer to the pre-2008-2009 market crash average. Figure 4 shows VIX performance over the past 10 years.

Figure 4 – VIX Index Performance
January 1, 2002 to July 4, 2012




Source: Bloomberg

At the time the BCUC heard evidence in the 2009 Proceedings, the VIX averaged approximately 25 in September 2009 while it averaged the improved level of 20.5 during the month leading up to July 4, 2012.

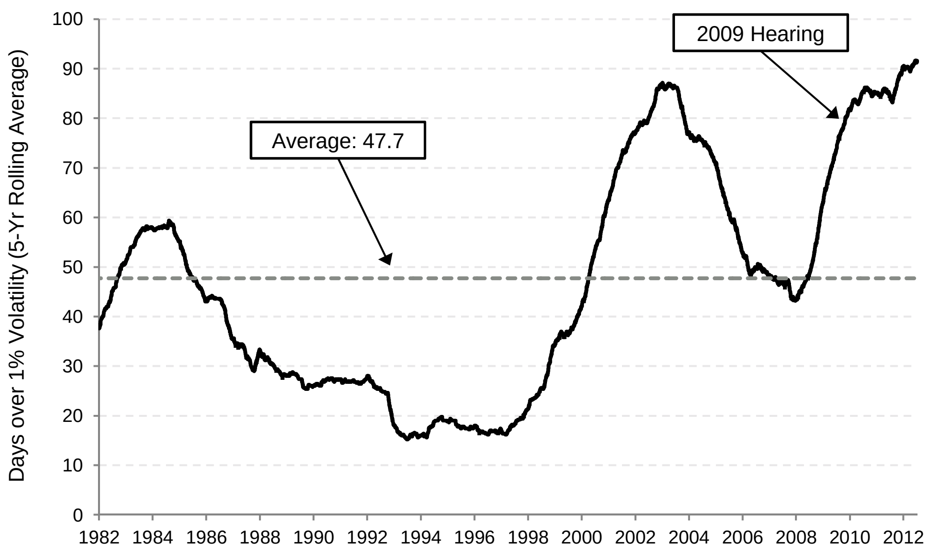
Actual or realized volatility in the equity capital market can be seen in the number of days in which the change in the value of the S&P/TSX Composite Index exceeds 1% (“1%+ Days”), that is, those days when the index fell or rose by more than 1% on any given day. From 1982 to July 2012, there were, on average, 47.7 1%+ Days annually.

In sharp contrast, the index experienced 126 1%+ Days in 2008 and 128 1%+ days in 2009.

2010 saw closer to average 1%+ Days with 51 such days. In 2011 the index bounced upward as it experienced 85 1%+ Days. So far in 2012 (to July 4, 2012) there have been 27 1%+ Days.

Figure 5 shows the 5-year rolling quarterly average volatility in the S&P/TSX Composite Index's value since 1982 measured by 1%+ Days. As shown in the chart, volatility rose dramatically through the technology, media and telecom crash and fell markedly afterwards. As the 2008-2009 market crash began to unfold, volatility rose rapidly again and has not abated substantially since that time. More recently, volatility levels have increased further.

Figure 5 – S&P/TSX Volatility
January 1, 1977 to July 4, 2012




Source: Bloomberg

Just how volatile the market can be was demonstrated in August 2011 as the S&P/TSX went on a wild ride with 14 1%+ Days (in the space of 22 trading days) which was equal to or greater than the aggregate number of 1%+ Days for each of 1989, 1992 and 1993 and one day short of 1985.

At the time the BCUC heard evidence in the 2009 Proceedings, the S&P/TSX experienced 77 1% Days over the preceding four quarters. The four quarters leading up to this point in 2012 have been significantly more volatile with 91 1%+ Days.

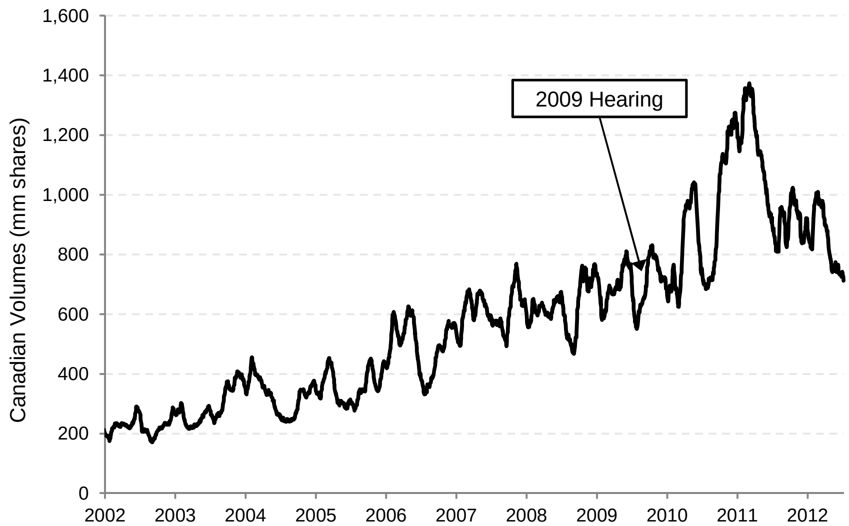
Trading Volumes

At the same time that the equity market has been experiencing higher volatility, it is also experiencing lower trading volumes. Liquidity in the equity market is low and has been declining over the past year, with Canadian stock exchange volumes down materially since December 2011. Trading volumes are down as investors increasingly remain on the sidelines waiting to see whether and to what extent current economic and financial developments will impact the market – yet another example of investor risk aversion.

Figure 6 demonstrates recent 20-day[6] rolling average market trading volumes in Canada since 2002.

[6] Trading days.

Figure 6 – Canadian Equity Market Trading Volumes
January 1, 2002 to July 4, 2012




Source: Bloomberg

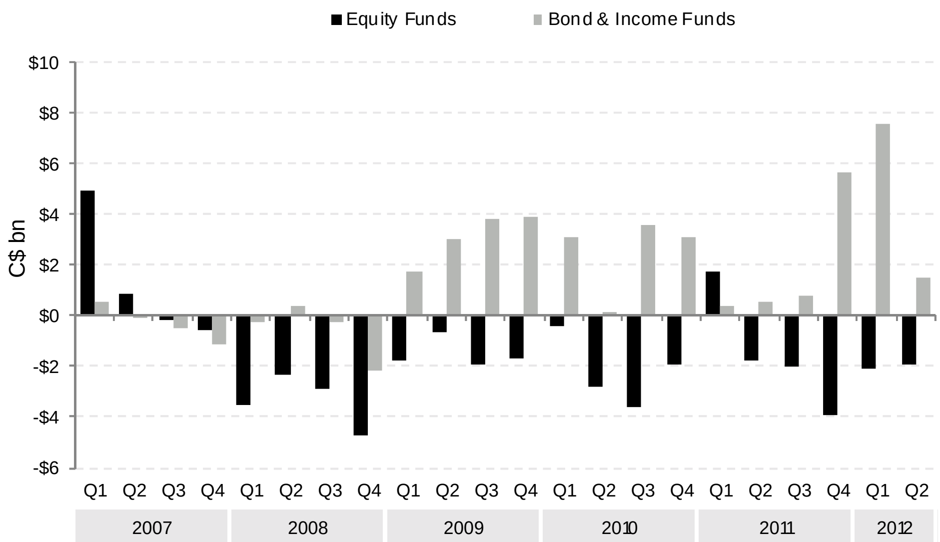
At the time the BCUC heard evidence in the 2009 Proceedings, 20-day rolling average market trading volumes were 784 million shares as of September 23, 2009. As of July 4, 2012, the 20-day rolling average market trading volumes were lower at 712 million shares. Moreover, today's lower market trading volumes come during a period when volumes have been on a declining, rather than rising, trajectory.

**Mutual Fund Flows**

With the exception of the Q1 2011, Canadian mutual fund funds flows remain in heavily negative territory for equity funds (and have been so for the past four years) while bond and income funds have enjoyed strongly positive fund flows. These funds flows are illustrative of investors' cautious approach to the equity market. Significant concerns remain in equity investment despite gains since the 2009 lows.

Figure 7 shows Canadian mutual fund flows since the beginning of 2007.[7]

Figure 7 – Quarterly Mutual Fund Flows
January 2007 to May 2012




Source: IFIC

At the time the BCUC heard evidence in the 2009 Proceedings, mutual fund equity fund flows were aggregated -$9.0 billion (outflows) for preceding 12-month period. Equity fund flows have worsened and amounted to -$10.8 billion (outflows) for the 12-month period leading to May 2012. On the other hand, bond and income fund funds flows were positive at the time of the BCUC heard evidence in the 2009 Proceedings at $6.5 billion for the 12-month period ending September 2009. They increased markedly since then with aggregate flows of $16.0 billion for the 12-month period ending May 2012.

[7] In 2007 IFIC reduced its mutual fund categories from three (Bond & Income, Dividend & Income and Equity) to two (Bond & Income and Equity). Because of the change mutual fund flows before 2007 cannot be meaningfully compared with those after 2007. Q2 2012 includes only two months of data as June data was not available at the time of writing.

## Market Evidence of Equity Valuations

S&P/TSX Composite Index P/E Ratio

Equity capital market valuations have been buffeted by significant market events over the past 10 years. Changes in the S&P/TSX Composite Index's P/E ratio over the period helps illustrate the point. The index's P/E ratio is a measure of the value of the index relative to the earnings generated by companies in the index. It is a widely used metric for measuring relative value for indexes and individual companies. A higher P/E ratio means the market is paying more for each dollar of income, meaning each dollar of income is more valuable or more expensive and, all else equal, indicates a lower cost of equity environment. Conversely, a lower P/E ratio means the market is paying less for each dollar of income, meaning each dollar of income is less valuable or less expensive and, all else equal, indicates a higher cost of equity environment.

The S&P/TSX's P/E ratio fell dramatically from over 30x to 20x early in the decade as the market came out of the technology, media, and telecom bubble. The ratio remained in a period of relative stability until late 2008 when the 2008-2009 market crash took hold. In a short four to five weeks the index's P/E ratio fell to a low of approximately 10x and stayed at that general level until mid-2009 when it began to improve to pre-crash levels. Beginning in early 2011, however, the index's P/E ratio began a prolonged fall, slumping to current sub-15x levels.

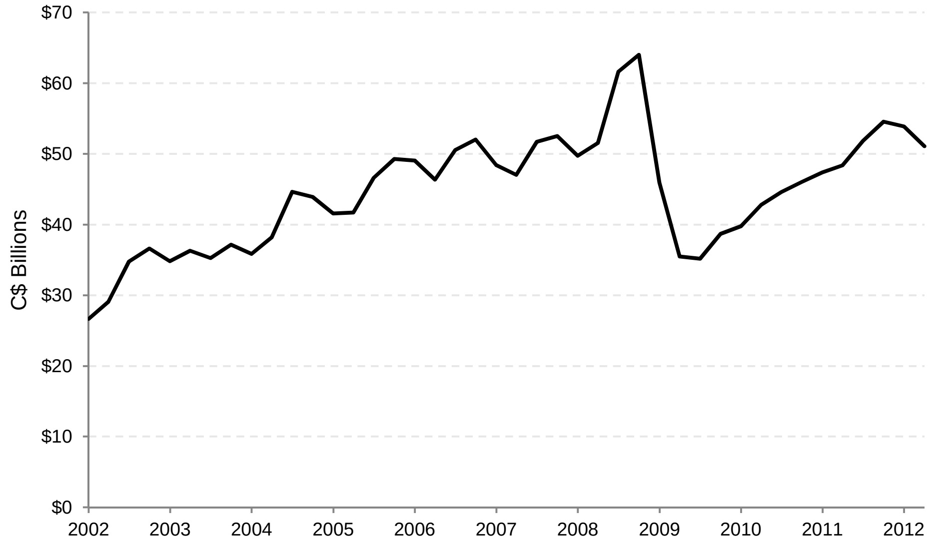
Figure 8 – S&P/TSX Composite Index Historical P/E Ratio
January 2002 to April 2012


Source: Bloomberg

At the time the BCUC heard evidence in the 2009 Proceedings, the S&P/TSX's P/E ratio averaged 17.2x in September 2009 whereas in the month leading up to July 4, 2012 the ratio averaged the materially lower level of 13.9x. Also, today's lower P/E ratio comes during a period where the ratio has been in decline in sharp contrast to the rising ratio environment when the 2009 hearing was held.

The falling trend in the S&P/TSX's P/E ratio over the past two years taken together with growth in corporate earnings during the same period as demonstrated in Figure 9, is compelling evidence that the cost of equity in Canada has been rising.

Figure 9 – Aggregate Cdn Quarterly Corporate B-Tax Earnings
January 2002 to March 2012




Source: Statistics Canada

Earnings/Bond Yield Spread

The market has been raising the bar on equity valuations to levels higher than was the case in the 1980s or 1990s which has escalated the risk premium on equities. The heightened bar on equity valuations marks a return to the more demanding market environments of the early 1960s and mid-1970s.

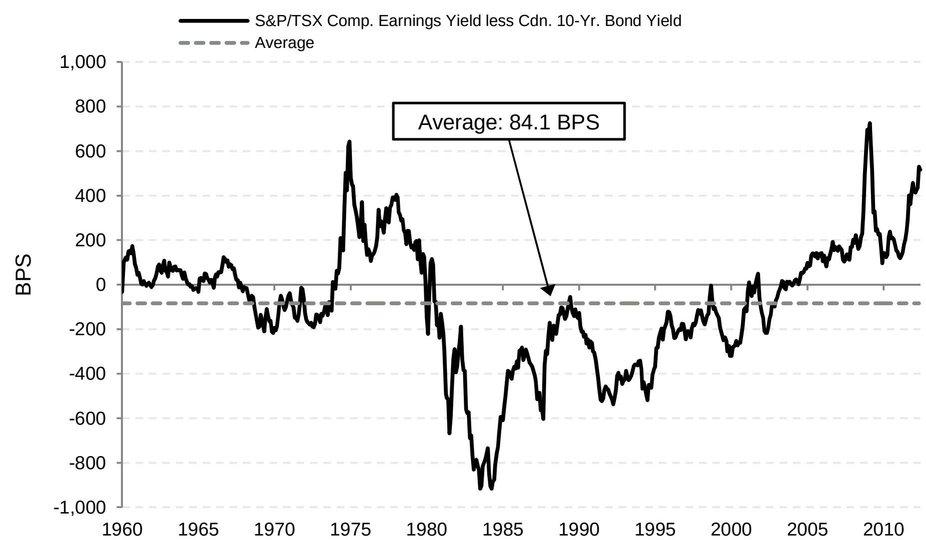
The raised bar on equity valuations can be seen in Figure 10, which shows the spread between the S&P/TSX Composite earnings yield[8] and the 10-year Government of Canada bond yield (the "Earnings/Bond Yield Spread") began to turn positive in 2003 and has remained positive since. The Earnings/Bond Yield Spread is one measure the market considers as an indication of whether the cost of equity is rising or falling. It is not a measure of the cost of equity. The

[8] Earnings yield is calculated by dividing S&P/TSX Composite operating earnings by the value of the S&P/TSX Composite.

return to sustained positive spread territory had not been seen in Canada for over 23 years.

Since turning positive in 2003 the Earnings/Bond Yield Spread continued to increase, spiking to an unprecedented level of almost 800 bps at the beginning of March 2009, staggeringly higher than the average spread of -84 bps since 1960. The Earnings/Bond Yield Spread briefly receded from its highs but has since returned to very high levels currently standing at 516, or approximately 600 bps higher than the long-term average.

Figure 10 – Earnings Yield – Gov't Canada Bond Yield Spread
1960 to June 2012




Source: DRI, BMO Capital Markets

From 2003 to late 2008 the spreads increase was largely the result of falling Government of Canada bond yields while equity valuations remained largely unchanged during the same period. When the Earnings/Bond Yield Spread blew out during the 2008-2009 market crash it was the result of the dramatic fall in S&P/TSX Composite Index valuations (see Figure 8 – S&P/TSX Composite Index Historical P/E Ratio) exacerbated by further falling Government of Canada bond yields. More recently, the return to heightened levels has been a function of the same phenomena of falling Government of Canada bond yields combined with falling equity valuations (resulting in increasingly higher earnings yields).

**Summary**

Overall Canadian equity capital markets are challenging and volatile. The S&P/TSX Composite Index has been on a downward trend for some months as investors are concerned about developments in sovereign debt (particularly the European sovereign debt crisis), monetary policy, and tepid global economic conditions. Trading volumes are down. Mutual funds continue to see strong flows into bond and income funds and high outflows from equity funds. The S&P/TSX Composite Index's P/E ratio has been on a downward trend since early 2011 and the Earnings/Bond Yield Spread is back at historical highs.

### *Debt Capital Market Conditions*

Capital markets are generally thought of as being chiefly comprised of both equity and debt capital markets. As debt is a fundamental source of capital for regulated utilities, it is important to understand debt capital market conditions when considering the overall regulated utility capital market environment. Generally speaking, when market conditions are weak, uncertain, or volatile, or where investors become more risk averse, one would expect to see wider corporate credit spreads[9]. On the other hand, where market conditions are strong and less volatile, or where investors are less risk averse, one would expect to see corporate credit spreads tighten.

---

[9] Credit spreads represent the yield difference between an issuer's bonds and the applicable Government of Canada "benchmark" bonds.

**Current Market Conditions**

Canadian corporate bond issuance year-to-date 2012 has been in line with 2011 and is expected to end with largely the same issuance levels as the previous year at $65 to $75 billion (2011-$77 billion). Credit spread tightening recently seen in the market was broad based with riskier credits outperforming to this point in 2012 after widening out more significantly in the latter part of 2011. Further spread tightening is unlikely given the volatile macro environment and record low benchmarks. Exogenous risks continue to impact market volatility in terms of both changes in credit spread levels and market access (ability to go to market).

Near-term exogenous risks include:

- European debt crisis
  - Pressure on Spanish and Italian bond yields
  - Continued concern over a break-up of the Eurozone despite positive Greek election results
- Depth and duration of European recession
  - Difficult to predict and expected to worsen
- Chinese growth slowing
  - Some fears of a hard landing
  - China, however, has ample policy tools to mitigate
- Recent mixed U.S. economic data
- U.S. elections in November
  - Could impact fiscal policy and potentially increase recession risks in 2013

The broader market volatility has increased the need for new issue concessions for high-grade infrastructure and utility issuers.

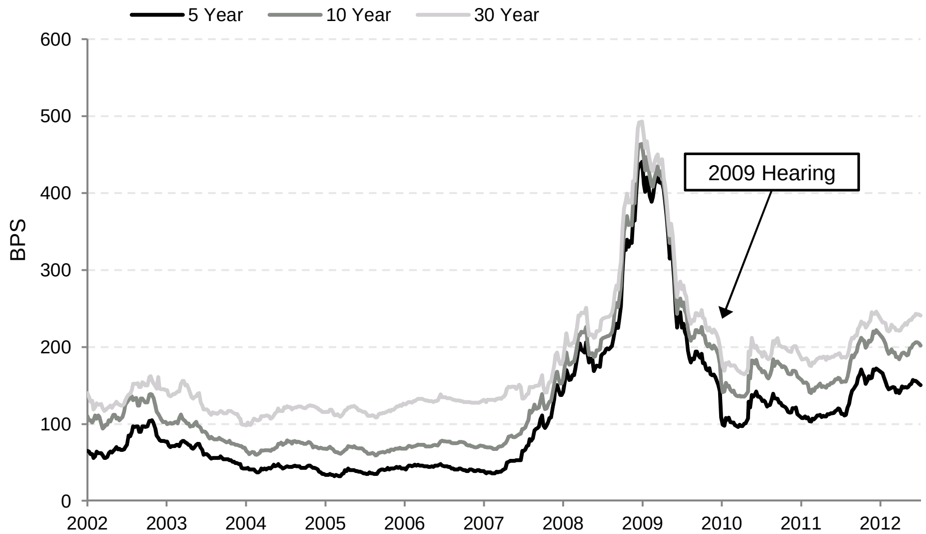
Recent increases in provincial spreads (i.e., Ontario) resulting in a compression to high-grade corporate spreads has many investors believing spreads are not wide enough to compensate for credit risk, particularly in the long end of the curve. That said, the corporate bond market is viewed as being undersupplied with the result that the market should see ongoing supportive bids for credit.

Benchmark Government of Canada rates are expected to rise over the coming years with little room for the increase to be offset by corporate spread tightening.

**Corporate Spreads**

Figure 11 shows generic Canadian A-rated 5, 10 and 30-year corporate bond spreads over the past ten years. The chart illustrates the remarkable climb in spreads during the 2008-2009 market crash and their subsequent decline. Although spreads have seen a strong recovery from their highs, they remain high relative to historic levels over the period. Investor appetite for risk in the debt capital market has generally diminished leading to an overall upward re-pricing of risk.

Figure 11 – Canadian Generic ‘A’ Spreads
January 2, 2002 to July 6, 2012

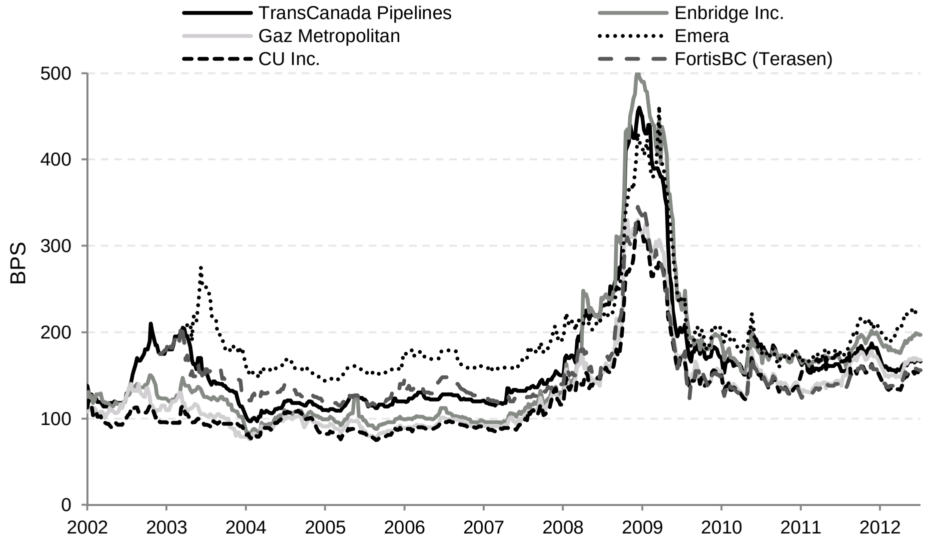



Source: BMO Capital Markets

At the time the BCUC heard evidence in the 2009 Proceedings, Canadian generic “A” spreads stood at roughly 186 bps (5-year), 219 bps (10-year), and 241 bps (30-year) during the week ended September 25, 2009. Spreads at the short end of the curve have improved since then at 150 bps (5-year) and 202 bps (10-year) while at the long end of the curve spreads are the same at 241 bps for the week ended July 6, 2012.

Similar developments have occurred in yield spreads for Canadian energy infrastructure companies. Figure 12 shows 30-year yield spreads for FEI, Gaz Métro, TransCanada, Enbridge, Emera, and CU over the past 10 years.

Figure 12 – Cdn Utilities Group 30-Year Spreads
January 2, 2002 to July 6, 2012



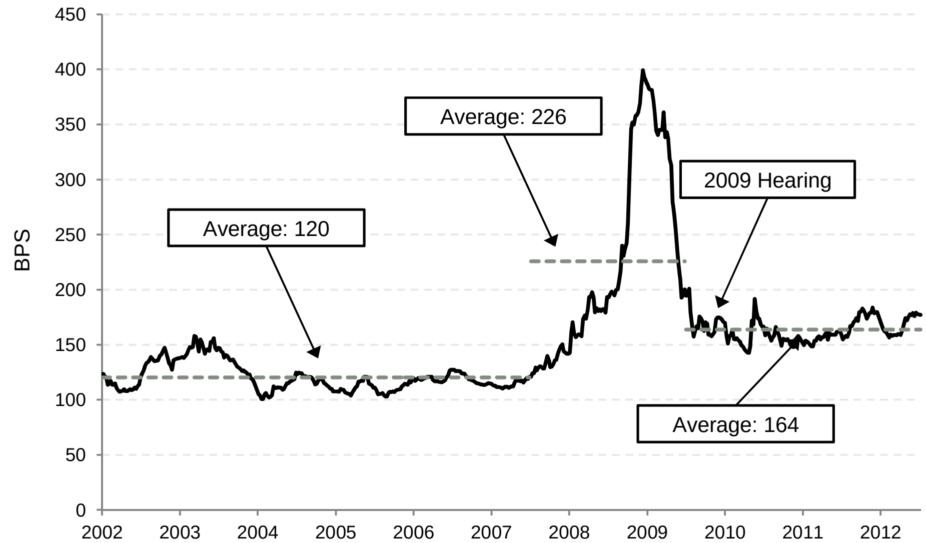

Source: BMO Capital Markets

As with generic A-rated Canadian corporate yield spreads, 30-year yield spreads for Canadian energy infrastructure companies rose dramatically beginning in mid-2007, have fallen substantially since then and remain at historically high levels over the period.

Figure 13 illustrates the average of the Canadian energy infrastructure companies' 30-year yield spreads over the past 10 years. Over the period from January 2002 to the extraordinary run up in spreads beginning in July 2007 30-year yield spreads for Canadian utilities had averaged 120 bps. 30-year yield spreads then leapt upward averaging 226 bps from June 30, 2007 to June 30, 2009 and came to the brink of 400 bps in late 2008.

Since then spreads recovered materially from their highs averaging 164 bps since June 2009 and well above the 120 bps pre-market crash level.

Figure 13 – Average Cdn Utilities Group 30-Year Spreads
January 2, 2002 to July 6, 2012



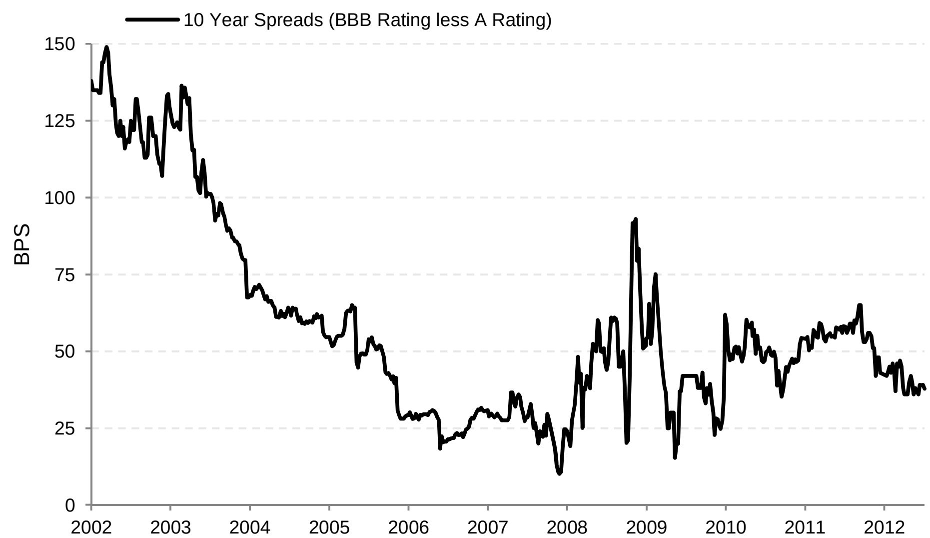

Source: BMO Capital Markets

At the time the BCUC heard evidence in the 2009 Proceedings, the average Canadian utilities group 30-year spreads were 163 bps on September 25. Their spreads have widened materially and stood at 177 bps as of July 6, 2012.

The spread between 10-year BBB/A-rated bond spreads have been very volatile over the past 10 years. Early in the period the spread between the two fell steadily from roughly 150 bps to a low of 10.1 bps on November 30, 2007. Since then the spread between the two jumped dramatically upwards to nearly 100 bps in late 2008 and falling back to below 25 bps in 2010. At present the spread stands at 37.8 bps on July 6, 2012.

Figure 14 illustrates the spread between generic 10-year BBB-rated bond spreads and A-rated bond spreads.

Figure 14 – 10-Year Generic BBB Spreads Less A Spreads
January 4, 2002 to July 6, 2012



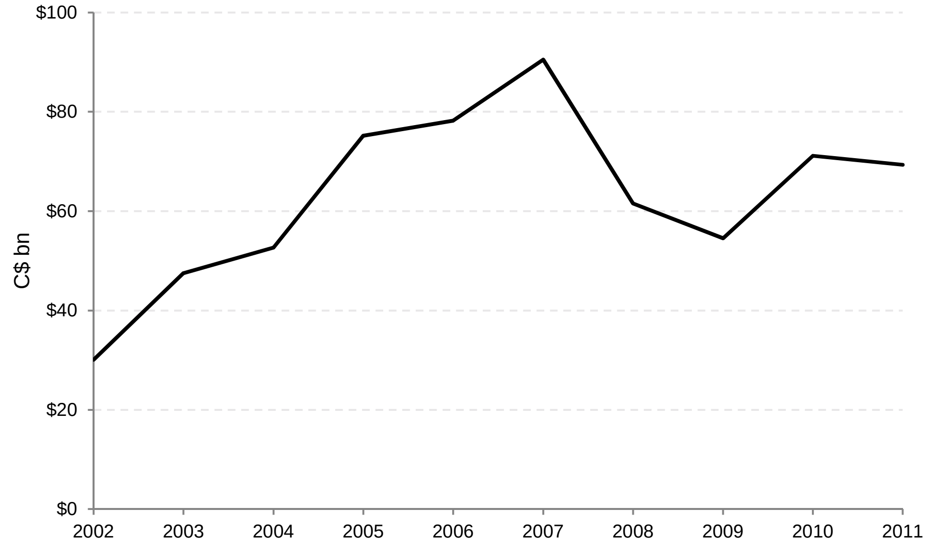

Source: BMO Capital Markets

Over the period generic BBB-rated bond spreads have been more volatile than generic A-rated bond spreads.

**Corporate Debt Issuances**

Corporate debt issuances had been increasing steadily from 2004 to their peak in 2007. During the 2008-2009 market crash corporate debt issuances dropped by approximately 40% from their high of $90.5 billion in 2007 to $54.0 billion in 2009. At $71.1 billion for 2010, corporate debt issuances had roughly rebounded to 2005 levels. Figure 15 shows aggregate Canadian corporate debt issuances over the past 10 years.

Figure 15 – Aggregate Cdn Corporate Bond Issuance
2002 to 2011




Source: BMO Capital Markets

2011 saw continued issuance strengthening as it posted corporate debt issuances of $69.4 billion. Issuances to July 2012 have amounted to $42.5 billion.

**Market Summary**

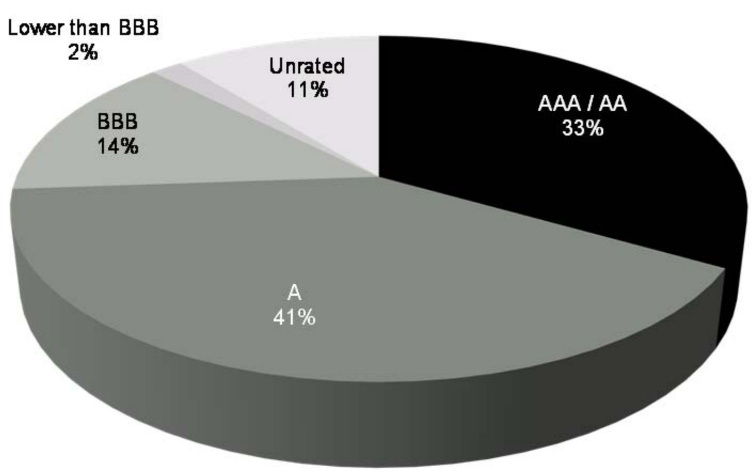
The Canadian debt capital market is in good condition as 2012 issuance levels are in line with 2011 and credit spreads tightened earlier this year after a period of widening in the latter part of 2011. That said, exogenous risks continue to impact market volatility. Despite good current market conditions, the average Canadian utilities group 30-year spreads are wider (181 bps) than they were at the time of the 2009 Proceedings (166 bps). The wider spreads are reflective of investor risk re-pricing and increased risk aversion.

**Corporate Debt Ratings Characteristics**

Canadian corporate debt issuance has historically been, and continues to be, overwhelmingly represented by A-category or higher rated debt.  Since the beginning of 2002, total A-category and above rated debt amounted to $520.5 billion representing approximately 74% of total Canadian corporate debt issuance over the period.

In contrast, total BBB-category rated debt issued amounted to just $96.3 billion or 14% of total corporate debt issuance over the period with lows of $4.2 billion in issuances in 2002, $3.8 billion in 2007, and $5.2 billion in 2008.  Figure 16 shows the breakdown of Canadian corporate issuances by credit rating since January 1, 2007.

Figure 16 – Cdn Corporate Bond Issuance by Rating
January 2002 to July 2012




Source: BMO Capital Markets

As illustrated in Figure 16 the BBB bond market remains very small in Canada.  Although the market has been growing and is increasingly accepted by Canadian investors, it, unlike the A-rated market, is still not robust, is at risk of closing down periodically, and is offering size constrained for long-dated (10+ year) financings.

There are numerous reasons, therefore, why it is critical for utility debt issuers to be A-category rated, including:

- the higher rating provides consistent and ready access to the debt market on reasonable terms and conditions through all business and financial cycles;
- A-rated debt yields are lower and less volatile than BBB-rated debt;
- the deeper, broader nature of the market (as seen in overall issuance levels demonstrated in Figure 16) can better supply the sector's need for capital as it faces significant future capital expenditure requirements; and
- it improves the utility's ability to issue longer-term debt to finance its long-lived assets.

**Rating Downgrade Impact on Bondholders**

It would be expected that a rating downgrade from, say, A- to BBB+ would cause an issuer's credit spreads to increase. How much the spread widens is a function of the then general debt capital market conditions, credit spreads between the two ratings categories (which can change significantly from one period to another – see, for example, Figure 14 – 10-Year Generic BBB Spreads Less A Spreads), and, of course, the reason for the rating downgrade.

Any increase in credit spreads reduces the market value of the issuer's outstanding bonds. In the case of FEI, a 1 bps increase in spreads would currently be expected to result in a $1.22/$1,000 reduction in bond market value. With an aggregate bond market value of $3.3 billion, a 1 bps increase in FEI's credit spreads would result in aggregate loss of more than $4 million to FEI bondholders.

As such, allowing or requiring a reduction in FEI's credit rating would directly and adversely affect bondholders who invested in FEI bonds with the reasonable expectation that the company's regulatory environment would protect their return on and of capital – not negatively affect the value of their investments.

**Institutional Investor Portfolios**

Typically institutional investors invest within bond investment guidelines defined by, among other things, bond credit ratings. Under such investment guidelines, investors can only invest a stipulated amount of capital in bonds with various credit ratings. Bond investors generally stay fully invested within their respective bond ratings "buckets" with the result that when held bonds are downgraded, from, say, A- to BBB+, their BBB+ bucket holdings can increase beyond that ratings bucket limit requiring portfolio rebalancing. The investor must sell BBB+ bonds to meet portfolio holding requirements. Depending on the investor's portfolio and desired holdings, it may need to sell the newly downgraded BBB+ bonds putting added upward pressure on those bonds' spreads.

**Small Bond Issuance Considerations**

Many of the pricing and spreads issues discussed above do not apply to small-sized debt issues by small, regulated utilities. Such offerings would generally be completed through one-off negotiated, private placement transactions basis rather through than public offerings. In such transactions offering costs can be significant, particularly on a relative cost basis given the smaller amount of capital being raised. Moreover, legal costs can be higher on an absolute basis compared to larger offerings by larger issues to the extent that larger issuers tend to have previously negotiated, outstanding trust indentures and offering documents are well developed through previous offerings.

Small bond offering sizes and the private placement structure, can negatively affect bond coupons. Typically small bond offerings are purchased by a small number of buyers (in some cases, only one buyer). As a result, the bonds are often highly illiquid with the result that the buyer(s) require yield premiums to reflect their illiquidity.

### *Government of Canada Bond Yields*

Government of Canada bond yields are used to establish corporate bond yields and are a primary determinant in the various risk premium models used to determine the cost of equity. As such, it is important to understand the Government of Canada bond market conditions and yields.

The 5, 10 and 30-year Government of Canada bond rates stood at 4.6%, 5.4% and 5.7%, respectively, at the beginning of 2002 and as of July 4, 2012 stood at 1.2%, 1.7% and 2.3%, respectively.

Figure 17 tracks the bond yields since the end of 2002. As shown, Canadian bond yields have been in steady decline despite a bump up following the 2008-2009 market crash and have recently tumbled to record low levels, even lower than those seen during the height of the 2008-2009 market crash. Some of the factors pushing Government of Canada bond yields to currently very low levels are the very same factors which would tend to put upward pressure on the cost of equity.

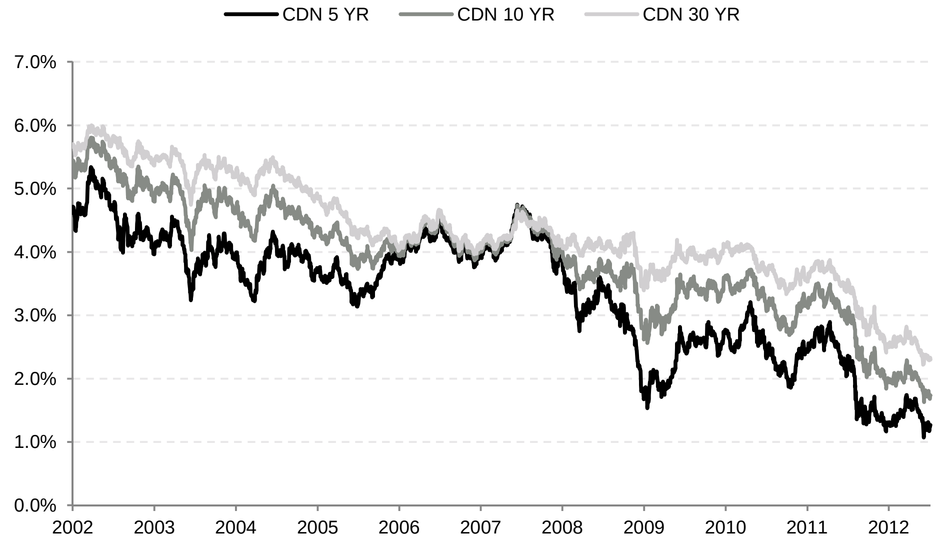
Foreign capital inflows into the Canadian bond market are increasing, reflecting two broad motivations:  safe-haven flows; and official diversification flows.  Euro area-led concerns about the global economy and financial markets are prodding safe-haven flows.  As repeated waves of risk aversion have crested, in which return of capital has mattered more than return on capital, investors have pushed yields in some safe-haven destinations into negative territory (e.g., Switzerland and Denmark).  While U.S. Treasuries are more likely to benefit from these flows than Government of Canada bonds, the quest for higher yields has led investors to overlook the Canadian market's relative liquidity deficiency (relative to U.S. Treasuries).

Official diversification flows into the Canadian market have grown as official investors (central banks and other reserve fund managers along with sovereign wealth funds) diversify away from U.S. Treasuries and U.S. dollars (and euros) to other "quality" destinations such as Canada, Australia and the Scandinavian nations (Sweden, Demark and Norway).  What attracts investors to these nations are their solid fiscal track records (amid ongoing concerns about sovereign debt) and their strong banking systems.

Also keeping yields historically low is relatively sluggish global economic performance and central bank reactions to it.  The relatively weak economic growth keeps a lid on inflation pressures and allows central banks to keep their policy rates lower than they otherwise would, generally in an attempt to spur economic growth.  In Canada's case, the overnight rate, which currently stands at 1%, contributes to low Government of Canada bond rates.

The 10-year bond average yield was 3.24% in 2010 and 2.78% in 2011.  BMO Capital Markets forecasts the 10-year bond average yield will stay at very low levels of 1.87% in 2012 followed by a modest rise to 2.48% in 2013.

Figure 17 – Gov't Canada Bond Yields
January 1, 2002 to July 4, 2012




Source: Bloomberg

At the time the BCUC heard evidence in the 2009 Proceedings, Government of Canada bond yields averaged 2.6% (5-year), 3.4% (10-year), and 3.9% (30-year) for the month of September. Those rates were materially lower at 1.2% (5-year), 1.8% (10-year), and 2.3% (30-year) during the month leading up to July 4, 2012.

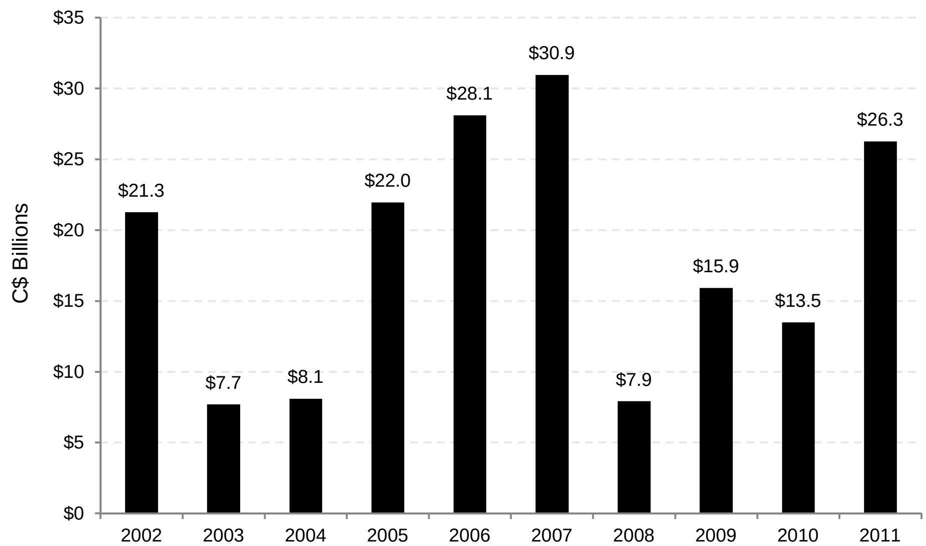
### *Financial Market Globalization*

The globalization of Canadian financial markets is continuing and at an increasingly rapid pace. Canadians are significant investors in foreign equities because of the attractive alternatives foreign equities have offered relative to Canadian opportunities in the context of risk adjusted returns and portfolio diversification. Financial markets are, and have been for some time, global in nature and Canadian investors are increasingly comfortable with and knowledgeable about U.S. and global markets.

## Cross Border Investment

The global nature of the capital markets is demonstrated by Canadian cross border investment activity. As illustrated in Figure 18, a net total of $181.7 billion was spent by Canadians purchasing foreign stocks over the past 10 years. Strong Canadian investor interest in foreign stocks continues.

Figure 18 – Net Cdn Purchases of Foreign Stocks
2002 to 2011

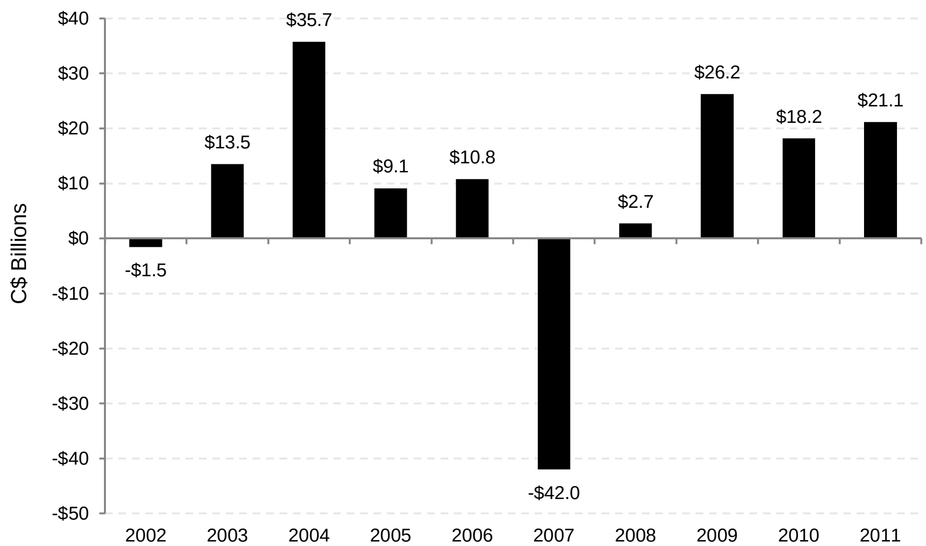



Source: Statistics Canada

On the other hand, over the past 10 years foreign investors have purchased a net total of $93.8 billion in Canadian stocks. Such purchases represent approximately 50% of the net purchases of foreign stocks by Canadians over the same period. Canadian purchases and sales of foreign stocks have vastly outpaced foreign purchases and sales of Canadian stocks. Over the 10-year period, for every $1.00 of Canadian stock purchased by foreign investors, Canadian investors purchased over roughly $1.95 in foreign stock. Figure 19 shows the flow of net foreign purchases of Canadian stock.

The amount of Canadian foreign investment activity is all the more remarkable relative to foreign investment activity in Canada in view of the size of the Canadian market compared to foreign markets, in particular, that of the U.S.

Figure 19 – Net Foreign Purchases of Cdn Stocks
2002 to 2011

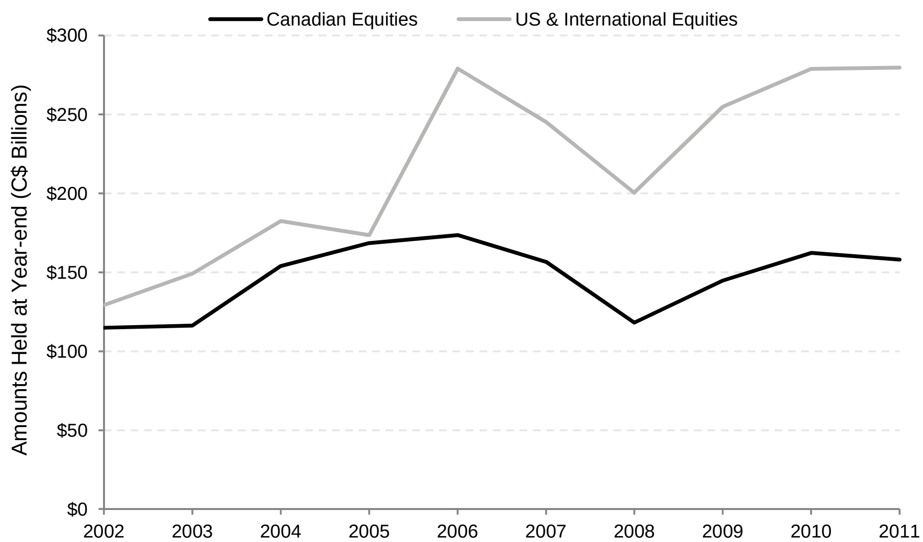



Source: Statistics Canada

In monitoring Canadian cross-border investment activity, it is also instructive to review the behavior of Canadian institutional pension fund investors over the past 10 years as reflected in asset mix reports provided by the Pension Investment Association of Canada. The association has virtually every major pension plan in Canada as a member and reflects the mainstream of pension fund activity in the Canadian financial market.

At the end of 2002, the Canadian equity component of total assets stood at 47.0% or $114.8 billion, slightly less than the U.S and international equity component which then stood at 53.0% or $129.3 billion. Since that time the gap between U.S. and international equities held by pension funds and their Canadian equities holdings has widened considerably. Figure 20 shows that the difference between U.S. and international equities and Canadian equities has been increasing over recent years.

Figure 20 – PIAC Sponsor Organization Cdn, U.S. & Int'l Asset Mix
2002 to 2011




Source: Pension Investment Association of Canada

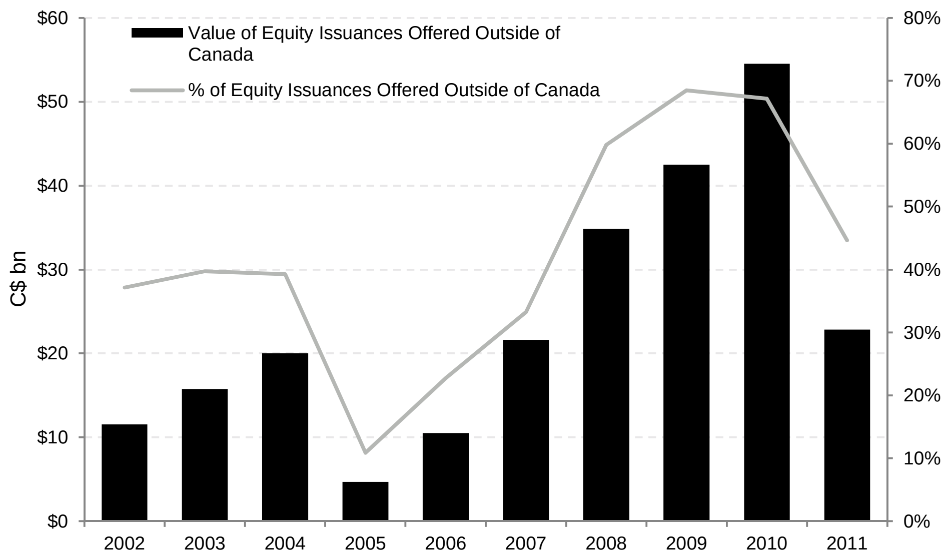
More recently, at December 31, 2011 the Canadian equity component of assets stood at 36.1% or $158.1 billion while the U.S. and international equity component stood at 63.9% or $279.7 billion. Total assets in the reported pension fund portfolios increased dramatically over the same period growing from $511.8 billion in 2002 to $1,049.6 billion in 2011.

**Cross Border Issuance**

Canadian issuers have been very active offering securities outside Canada with a particular focus on the U.S. Since 2002 Canadian issuers, including governments, have raised just over $2.4 trillion in capital through offerings of equity, debt, and preferred shares. Of that amount, $938 billion, or 38.4% of all Canadian issued securities, was issued or offered for sale outside Canada (the vast majority being in the U.S.). Such issues were undertaken through both cross-border public offerings and private placements. With respect to equity alone, the percentage of equity issued or offered for sale outside Canada averaged 43% annually over the period with a high of 69% in 2009.

Figure 21 shows where Canadian common equity has been issued and/or offered for sale over the past 10 years.

Figure 21 – Cdn Equity Issuance Jurisdictions
January 1, 2002 to December 31, 2011




Source: BMO Capital Markets

Significant offerings of Canadian securities outside Canada are expected to continue and, in the case of the energy infrastructure sector, to grow as massive amounts of capital will be required to build proposed infrastructure projects.

**Structural Developments**

The trend towards globalization of Canadian financial markets has been accelerated and supported by recent tax changes in Canada. Canadian investors, both retail and institutional, have fewer impediments than ever to investing outside Canada since the federal government eliminated the foreign property rule (the "FPR") in 2005. The FPR restricted the portion of savings which could be invested in foreign assets within registered retirement savings plans ("RRSPs") and registered pension plans.[10] The impact of the FPR's elimination on Canadian's investing abroad was neatly summarized when, in announcing the tax change, the then federal Minister of Finance, Ralph Goodale, said:

> "**To expand the investing universe for Canadians and offer them the potential to achieve greater diversification and a more secure future,** we will remove the foreign property limit – effective immediately."[11] (emphasis added)

The 2005 federal budget, which introduced the FPR's elimination, recognized the integration of Canadian capital markets with global markets as part of the reasoning behind its elimination. It stated:

> "The Foreign Property Rule (FPR) was introduced in 1971 to ensure that a substantial proportion of tax-deferred retirement savings flowed to Canadian companies and provided support for the development of Canada's capital markets. **As these markets have grown, matured, and become more integrated with global capital markets**, access to capital for Canadian companies has improved substantially."[12] (emphasis added)

As a senior Department of Finance official noted about the tax change, the FPR's elimination improves diversification opportunities for retirement investments and increases the international competitive position and foreign investment capabilities of Canada's pension funds and fund

---

[10] Initially, foreign asset holdings were limited to 10% of plan assets in 1971, increased to 20% in 1994 and further increased to 30% in 2001.

[11] Ralph Goodale, February 23, 2005 Budget Speech.

[12] Department of Finance Canada, *The Budget Plan 2005*, pg. 165.

management companies.[13] With the FPR's repeal pension funds and RRSP investors have a vastly improved ability to cut and run to foreign markets when they are dissatisfied with Canadian expected returns on equity.

With the elimination of the foreign property rule foreign issuers began offering bonds in the Canadian debt capital market. Such bonds have come to be generally referred to as "maple bonds" reflecting the Canadian dollar denomination and Canadian market nature of the bonds. The growth of the maple bond market evidences the globalization of the Canadian debt capital market and signals increased competition for Canadian-issued debt capital.

The expansive and deepening globalization of the Canadian debt capital market has resulted in a strong sensitivity to events in foreign markets. As events impact foreign debt capital markets (either positively or negatively) capital flows from or to the Canadian market and, accordingly, affects our market in terms of availability and pricing of debt capital.

Regarding outbound Canadian capital, on September 21, 2007, Canada's Finance Minister and the U.S. Treasury Secretary signed a protocol to the Canada-U.S. Tax Convention which would, among other things, eliminate withholding tax[14] on cross-border interest payments. At the time the Canadian income tax act provided exemptions from Canadian withholding tax on interest under limited circumstances which generally only applied to medium and long-term debt.[15] On

[13] Xtalks Elimination of the Foreign Property Rule Webinar, October 26, 2005, *Foreign Property Rule, Context for its Elimination and Potential Impacts.*

[14] Canada imposed a 25% withholding tax on interest paid to non-residents. By tax treaty the 25% rate was often reduced but not to anything below 10%.

[15] The exemptions only applied to non-Canadian entities lending into Canada where no more than 25% of the principal is mandatorily repayable within the first five years.

December 15, 2008, Canada and the United States announced that the protocol had entered into force.

This change had significant implications for Canadian short-term debt issuers who gained access to the U.S. debt capital market without the impediment of a withholding tax. The tax had historically made such access impractical. The repeal of the withholding tax means that Canadian residential mortgages, auto loans, and other consumer assets are able to access the U.S. securitization market. The elimination of the withholding tax on cross-border interest payments further globalizes the Canadian financial market.

The Bank of Canada has frequently commented on the globalization of the Canadian economy and financial markets over the past several years. In its most recent medium-term plan, the bank stated:

> "From a Bank-wide perspective, we face a set of important external challenges over the next three years. Globalization, and integration of national economies and financial markets, are at the root of significant change in the global economy, with ramifications for Canada's economy. Rapid change is under way in the financial services sector in terms of consolidation, restructuring, and the development of new financial instruments, market practices, and regulation." [16]

The bank goes on to say in the same report that:

> "Increased globalization of products and financial markets and the emergence of large new economic powers are not only contributing to significant change in the global economy, but are also leading to important adjustments in the Canadian economy." [17]

[16] Bank of Canada, Medium-Term Plan 2007-2009, Moving Forward: Building the Future Together, at page 6.

[17] Bank of Canada, op. cit., at page 13.

In June of 2007, Tiff Macklem, Deputy Governor at the Bank of Canada spoke to the Winnipeg CFA Society in which he observed that Manitoba, "like the rest of Canada, is very much affected by global economic forces" and that Manitoba, "and Canada as a whole, are very much a part of the integrated world economy." He also pointed out that:

> "Global integration has also been affecting international savings and investment flows. Indeed, in the past dozen or so years, what is sometimes called "financial openness" has increased significantly. Since 1995, the stock of cross-border investment in advanced countries has grown from about 40 per cent of GDP to more than 120 per cent of GDP, and emerging markets have seen a similar increase, albeit from a lower base." [18]

**Implications**

Canadians pursue investment opportunities and returns in the U.S. and foreign markets and increasingly so over the recent years. At the same time, Canadian issuers are raising substantial capital outside Canada. These facts support the views that:

- Canadian companies compete for capital with non-Canadian issuers investment opportunities; and
- expected returns on capital in other jurisdictions, particularly those in the U.S. regarding allowed returns on capital available to U.S. utilities, are relevant and should be taken into consideration when determining whether allowed returns on equity for Canadian utilities are fair and reasonable.

[18] Tiff Macklem, Deputy Governor at the Bank of Canada to the Winnipeg CFA Society, Winnipeg, Manitoba, 21 June 2007.

### *Acquisition Price to Book / Rate Base to Book Value Ratios*

Nothing can be learned about the appropriateness of allowed returns on equity from recent Canadian merger and acquisition activity involving regulated assets.

It is true that regulated assets can trade at multiples greater than 1.0x rate base in merger and acquisition transactions. Seeing that, some have suggested these multiples show allowed ROEs are more than fair and should be reduced to a point where acquisition prices are more in the order of 1.0x rate base. The thinking goes that if a buyer pays 1.1x rate base for an asset with a 9.0% ROE, the buyer is accepting, at most, an 8.2% ROE (9.0% / 1.1 = 8.2%).[19] Conversely, if the buyer required a 10.0% ROE, the purchase price would amount to 0.9x rate base (9.0% / 0.9 = 10.0%).

On the surface such thinking appears logical. It is, however, a deception. This is so because the buyer's expected returns on equity are supported by many factors other than just allowed ROEs, including transaction strategic rationale and structuring, buyer ability to pay, and other considerations relating to the quality (or more accurately, the lack thereof) of acquisition transaction data.

**Transaction Strategic Rationale and Structuring**

When considering ROEs stemming from an acquisition of regulated assets buyers generally include some or all of the following strategic factors in supporting acquisition prices including:

---

[19] I say "at most" because if all the purchase price is allocated to equity, the presumed ROE would be less than 8.2%.

- geographic diversification;
- establishing a strategic foothold in a new market; and
- protecting the buyer's regulated asset franchise.

Fortis Inc.'s acquisition of CH Energy is a good recent example of strategic rationale associated with a regulated asset acquisition. In its February 21, 2012 press release announcing the CH Energy acquisition, the company stated:

"The business operated by CH Energy Group is attractive to Fortis for the following reasons:

(i) **It enables Fortis to enter into the U.S. regulated electric and gas distribution business** with a reasonably sized utility;

(ii) The Acquisition is expected to be **immediately accretive to earnings per common share**, excluding one-time transaction expenses;

(iii) CH Energy has a strong balance sheet and Central Hudson has strong investment-grade credit ratings;

(iv) Central Hudson, a single-state utility, operates a well-maintained electric and gas distribution system, serving a diversified, primarily residential and commercial customer base;

(v) Central Hudson operates principally under cost-of-service regulation. The utility has earned stable returns and is allowed timely recovery of costs related to purchased electricity and natural gas supply, transmission and capital programs. Other positive mechanisms include full recovery and deferral provisions for pension and other post-retirement benefit expense, manufactured gas plant site remediation and revenue decoupling mechanisms. For the three years beginning on July 1, 2010, Central Hudson's rates have been established using a **10% return on equity and a capital structure containing 48% common equity**;

(vi) Central Hudson's continued investment in its electric and gas businesses is **expected to result in attractive rate base growth**; and

(vii) It increases **diversification of regulated assets and earnings** by geographic location and regulatory jurisdiction." (emphasis added)

Buyers will also consider various financial and structuring considerations including, among others:

- expected growth in the regulated asset's rate base;
- the need to include a "control premium" when purchasing a business;

- expected increases in allowed ROEs (generally stemming from changing economic circumstances);
- opportunities to increase the deemed equity component of the regulated asset's capital structure;
- anticipated operating efficiencies which would allow the buyer to generate earnings in excess of allowed returns;
- the ability to implement performance based regulation or other incentive fee and cost improvement sharing structures;
- the ability to deduct interest on regulated asset ownership structure debt in Canada and in the buyer's home jurisdiction (double dip interest deductibility);
- access to other, higher ROE assets or businesses which are acquired alongside the regulated assets; and
- collateral benefits (synergies) may be generated between the acquired regulated assets and assets already owned by the buyer.

Any of these financial factors can directly increase a buyer's expected ROE derived from the acquisition.

<u>Rate Base Growth</u>

As noted above, rate base growth can be cited as a supporting reason for regulated asset purchase prices which may result in elevated purchase price-to-book ratios. When purchasers expect substantial rate base growth, they consider the purchase price in the context of aggregate rate base investment over the life of the asset including the initial purchase price and all additional capital to be invested in the asset. As a result, an apparently elevated purchase price-to-book ratio will fall overt time as the purchase price premium is spread over an increasingly larger rate base due to ongoing rate base investment.

AltaLink's 2001 purchase of Alberta transmission assets from TransAlta for $828 million is a good example of the issue. While the initial price-to-rate base value of the transmission assets was approximately 1.32x, AltaLink's aggregate purchase price-to-rate base value after substantial post-acquisition investment has pushed the aggregate price-to-rate base down to less than 1.1x. Table 1 provides the calculation of the relevant price-to-rate base calculation.

Table 1 – AltaLink Investment Price to Rate Base Metrics

| | |
|---|---|
| **Purchase Metrics** | |
| Transmission System Acquisition Price | $829 |
| Original Rate Base Value | $626 |
| Acquisition Price:BV (rate base) | 1.32x |
| **Current Rate Base Metrics** | |
| Rate Base Growth | $1,920 |
| Current Rate Base (mid-year 2012) | $2,546 |
| Total Rate Base Cost (acquisition price + net follow-on investment) | $2,749 |
| Aggregate Price to Rate Base | 1.08x |

Source: Public disclosure, regulatory filings

AltaLink's expected rate base growth for the 2013 and 2014 test years would further reduce the aggregate price-to-rate base value to 1.04x.

Control Premiums

Generally buyers pay a "control premium" when acquiring a business. The premium reflects the fact that on closing, the buyer will control the business and will make all decisions regarding how the business will be operated. The phenomenon is one of the important reasons why transaction comparables tend to provide higher valuations than trading comparables.

As a result, elevated transaction price-to-book ratios can also be partly explained by control premiums and not buyer expected returns on equity.

Financial Structuring

One example of using financial structuring to increase ROEs can be seen in Kinder Morgan Inc.'s November 2005 acquisition of Terasen Inc. for U.S. $5.6 billion. The acquisition was structured to use double dip interest deductibility and increased leverage to increase returns on equity. The transaction was to be financed with 20% equity and 80% debt comprised of a combination of assumed debt (U.S.$2.5 billion) and newly issued debt (U.S.$2.0 billion). In a research report analyzing the transaction, former CIBC World Markets research analyst Matthew Ackman specifically mentioned the Kinder Morgan double dip structure when he wrote:

> "Interest on this debt [U.S. $2.0 billion in new debt] will be deductible in Canada and the U.S., reducing the effective cost of debt to about 2% after tax."[20]

Of course, there are risks associated with using any of the financial factors listed above to increase ROEs. One of the most serious risks is the risk that the applicable regulator takes exception to elements of the acquisition structure and requires modifications to the transaction, modifies returns associated with the regulated assets, reduces or prohibits expected operating synergies, or outright prevents the acquisition. There is also the risk that strategic and financial considerations used to support the acquisition price fail to materialize.

Returning to the Kinder Morgan/Terasen transaction, less than two years after acquiring Terasen in August 2005, Kinder Morgan sold Terasen Gas to Fortis Inc. in February 2007 for $3.7 billion (including the assumption of $2.3 billion in debt) and recorded an impairment charge of U.S. $650.5 million on the sale. Two months later in April 2007, Kinder Morgan sold the

[20] Matthew Ackman, Equity Research Industry Updates, Pipelines, Utilities & Power, "*Kinder Just "Trusted" Terasen; Who's Next*?" at page 2.

TransMountain pipeline system[21] to Kinder Morgan Energy Partners LP for U.S. $550 million (including the assumption of debt) and recorded yet another impairment charge, this time in the amount of U.S. $377 million.

With impairment charges of just over U.S. $1.0 billion associated with Kinder Morgan's acquisition of Terasen and subsequent dispositions, the risk that financial considerations can fail to yield sought after purchase price support is self-evident.

These examples show that regulated asset acquisitions should not be used in determining allowed returns in a regulatory context. With strategic and financial considerations at work coupled with regulatory and financial risks, observers cannot reasonably determine buyer expected returns on capital.

**Ability to Pay**

The view that regulated assets should transact at price-to-book values of 1.0x and that if they don't, such transactions are indicative of lower buyer expected returns, is incorrect. That this is so becomes apparent in the context of an actual, commonly relied upon acquisition metric, earnings per share ("EPS") accretion/dilution[22] – a key (though not the only) supporting rationale for energy infrastructure acquisitions. Investors are generally supportive of EPS accretive acquisitions and less so, if not opposed to, EPS dilutive acquisitions.

---

[21] The TransMountain pipeline system was among the assets owned by Terasen at the time of Kinder Morgan's acquisition of Terasen.

[22] An acquisition is accretive to a buyer's EPS if, after the acquisition, the buyer's EPS is higher than it was prior to the acquisition, taking into consideration any equity issuance in connection with the acquisition.

To understand the point, one must first obtain relevant trading multiples for potential regulated asset buyers, in this case, Canada's energy infrastructure companies. Table 2 summarizes trading multiples for a number of Canada's energy infrastructure companies.[23]

Table 2 – Cdn Energy Infrastructure Company Trading Comparables

| Company | Company Market Value | | | 2012 Estimates (3) | | | Current |
|---|---|---|---|---|---|---|---|
| | Share Price (1) | FD Market Cap | EV (2) | EV / EBITDA | P/E | Yield | Price to Book |
| | (C$) | (C$ mm) | (C$ mm) | (ratio) | (ratio) | (%) | (ratio) |
| Enbridge | $40.56 | $32,963 | $56,608 | 15.6x | 24.4x | 2.8% | 4.4x |
| TransCanada | $43.25 | $30,503 | $48,862 | 10.6x | 19.1x | 4.1% | 2.0x |
| Canadian Utilities | $66.38 | $8,501 | $13,641 | 9.3x | 16.3x | 2.7% | 1.8x |
| Pembina | $26.20 | $7,513 | $9,750 | 15.1x | 18.2x | 6.1% | 7.8x |
| Brookfield Renewable EP | $28.52 | $7,486 | $14,018 | 12.5x | nmf | 4.9% | 1.2x |
| Fortis | $32.65 | $6,906 | $15,193 | 11.9x | 19.1x | 3.7% | 1.8x |
| Inter Pipeline | $19.10 | $5,140 | $8,199 | 14.0x | 18.4x | 5.5% | 3.4x |
| Emera | $34.05 | $4,259 | $7,860 | 11.5x | 20.1x | 4.0% | 2.8x |
| TransAlta | $17.58 | $3,991 | $8,707 | 8.1x | 18.2x | 6.6% | 1.5x |
| Keyera | $43.05 | $3,338 | $4,049 | 13.3x | 24.7x | 4.7% | 3.8x |
| AltaGas | $29.13 | $3,055 | $5,434 | 15.2x | 22.6x | 4.8% | 2.6x |
| Enbridge Income Fund | $23.51 | $2,429 | $3,581 | 14.4x | 19.0x | 5.3% | 7.2x |
| Veresen | $12.15 | $2,366 | $3,771 | 10.2x | 28.0x | 8.2% | 1.9x |
| Capital Power | $23.88 | $2,323 | $4,881 | 10.2x | 16.5x | 5.3% | 1.6x |
| Northland Power | $17.98 | $2,139 | $3,334 | 18.7x | nmf | 6.0% | 3.1x |
| Gibson Energy | $20.17 | $2,062 | $2,602 | 9.3x | 22.5x | 4.9% | 2.3x |
| Atlantic Power | $13.34 | $1,591 | $3,548 | 10.3x | nmf | 8.6% | 1.9x |
| Algonquin Power | $6.55 | $1,047 | $2,044 | 15.6x | 30.1x | 4.4% | 1.9x |
| Average | | | | 12.5x | 21.1x | 5.1% | 2.9x |
| Median | | | | 12.2x | 19.1x | 4.9% | 2.1x |

1. Prices and exchange rates as at 04-Jul-12.
2. Fully diluted market capitalization plus total debt, less cash and investments in unconsolidated affiliates.
3. Consensus estimates from FactSet.

It is instructive to consider P/B ratios resulting from various assumptions regarding corporate P/E trading multiples and allowed ROEs associated with targeted assets. Table 3 summarizes the price-to-book values a buyer could pay for a regulated asset based on a range of P/E trading multiples and a range of regulated asset allowed ROEs. To be conservative, buyer P/E trading multiples are adjusted four "turns" downward[24] to a P/E "purchase" multiple which would ensure

[23] Energy infrastructure companies with market capitalizations greater than $1 billion.

[24] A four "turn" adjustment means that the buyer's P/E trading multiple is reduced by four turns. For example, if the buyer traded at a P/E multiple of 18, the multiple is reduced to 14.

the acquisition is EPS accretive.

As demonstrated in Table 2, the range of P/E trading multiples used in Table 3 is typical of, if not more conservative than those of, Canadian energy infrastructure companies. As a point of reference, Canada's energy infrastructure companies are currently[25] trading at an average P/E of 21.1x.

The shaded area in Table 3 indicates those combinations of allowed ROEs and buyer P/E trading (purchase) multiples which would allow a buyer to pay more than 1.0x price-to-book value for a regulated asset on an EPS accretive basis.

Table 3 – P/BV Multiples Derived from Purchaser P/E Ratios and Allowed ROEs

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Trading Multiple** | | 17.0x | 18.0x | 19.0x | 20.0x | 21.0x | 22.0x | 23.0x | 24.0x |
| **EPS Accretion Buffer** | | 4.0x | | | | | | | |
| **P/E Purchase Multiple** | | **13.0x** | **14.0x** | **15.0x** | **16.0x** | **17.0x** | **18.0x** | **19.0x** | **20.0x** |
| **Allowed ROE** | 5.0% | 0.65x | 0.70x | 0.75x | 0.80x | 0.85x | 0.90x | 0.95x | 1.00x |
| | 6.0% | 0.78x | 0.84x | 0.90x | 0.96x | 1.02x | 1.08x | 1.14x | 1.20x |
| | 7.0% | 0.91x | 0.98x | 1.05x | 1.12x | 1.19x | 1.26x | 1.33x | 1.40x |
| | 8.0% | 1.04x | 1.12x | 1.20x | 1.28x | 1.36x | 1.44x | 1.52x | 1.60x |
| | 9.0% | 1.17x | 1.26x | 1.35x | 1.44x | 1.53x | 1.62x | 1.71x | 1.80x |
| | 10.0% | 1.30x | 1.40x | 1.50x | 1.60x | 1.70x | 1.80x | 1.90x | 2.00x |
| | 11.0% | 1.43x | 1.54x | 1.65x | 1.76x | 1.87x | 1.98x | 2.09x | 2.20x |
| | 12.0% | 1.56x | 1.68x | 1.80x | 1.92x | 2.04x | 2.16x | 2.28x | 2.40x |

Clearly, there are ample scenarios where buyers have the ability to pay more than book value to acquire regulated assets on an EPS accretive basis. Each arises where a buyer's P/E purchase multiple[26] is higher than the inverse of the allowed ROE. If investors are highly focused on EPS, and they are, and a buyer has strong P/E valuations to support accretive acquisitions, it can do so and expect to be rewarded by the market for the smart use of those valuations. The reward will,

[25] As July 4, 2012.

[26] As adjusted downward to provide an EPS accretion buffer.

not surprisingly, come in further market support and may even result in yet stronger P/E market valuations.

As an example of how this approach works, Table 4 illustrates a hypothetical acquisition transaction using Emera Inc. as the acquirer. I use Emera because its current trading P/E multiple of 20.1x is close to the average P/E multiple of the Canadian energy infrastructure companies listed in Table 2.

As demonstrated in the table, Emera could acquire a large, $2.5 billion regulated asset at an initial purchase price-to-book ratio[27] of just short of 1.7x and still have the acquisition generate approximately 2.0% EPS accretion.[28] With an equity requirement of $1.4 billion on the purchase, representing one-third of Emera's current market capitalization, it may be challenging for the company to finance the transaction through a treasury offering of common shares. As an alternative, the company could issue shares to the vendor as consideration for the purchase price. Were it to do so, there would be no underwriters' fees payable with the result that the transaction EPS accretion would increase to 3.0%.

---

[27] I say "initial purchase price-to-book" ratio because as already discussed, price-to-book ratios decline over time as additional investments are made in rate base.

[28] BMO Capital Markets equity research estimates (including current P/E) were used for the analysis the table.

Table 4 – Example Regulated Asset Purchase

| | |
|---|---|
| **Emera - Current** | |
| Recent Share Price (June 6, 2012) | $33.79 |
| Issued and Outstanding Shares | 123.6 |
| 2012E Earnings | $210.1 |
| 2012E EPS (BMO CM Estimate) | $1.70 |
| Current P/E | 19.9x |
| **Regulated Asset** | |
| Rate Base | $2,500.0 |
| Equity Component | 35.0% |
| Total Equity | $875.0 |
| Allowed ROE | 9.5% |
| Earnings | $83.1 |
| **Transaction Parameters** | |
| Equity Purchase Price | $1,443.8 |
| Purchase Price/BV (Equity) | 1.65x |
| Assumption of Debt | $1,625.0 |
| Aggregate Purchase Price | $3,068.8 |
| Purchase Price/Rate Base | 1.2x |
| **Emera Share Issuance Costs** | |
| New Issue Discount | 2.5% |
| Underwriters' Fees | 4.0% |
| New Issue Share Price | $31.59 |
| **Emera Pro Forma Analysis** | |
| Shares Issued | 45.7 |
| Total Pro Forma Outstanding Shares | 169.3 |
| Pro Forma Earnings | $293.2 |
| Pro Forma EPS | $1.73 |
| **Accretion** | **1.9%** |

As a result, reducing allowed ROEs to account for regulated asset acquisitions made at price-to-book values greater than 1.0x punishes acquirers for using strong market valuations to complete transactions. This makes no sense. Companies rewarded by the market with strong P/E valuations because of quality management and assets, attractive growth, and good operations have the opportunity to use those strong valuations to support the company’s future growth and development. Using strong P/E valuations to make smart, accretive acquisitions has nothing whatsoever to do with whether a regulated asset buyer is satisfied with allowed ROEs.

**Other Considerations**

Aside from the strategic and financial reasons which may be used to support strong regulated asset purchase prices, there are there are several key reasons why such regulated asset transactions should not be used in attempting to derive purchaser ROE expectations.

No Valuation Metrics Applicable

No acquisition valuation metrics, including price to book, price to earnings, or enterprise value to EBITDA, reveal anything about purchaser-expected returns on an acquisition. All such metrics are a reflection of two inputs, purchase price (which can be objectively determined) and some financial measure. The financial measures may be historical (for example, last 12 months EBITDA or earnings or book value at the time of the acquisition) while some can be forward looking (for example, estimated future EBITDA and earnings).

Generally the historical measures can be objectively determined while forward looking measures cannot be. This is because only the acquirer (and certain of its advisers) knows what assumptions were made regarding, among other things, future cash flow, earnings, maintenance capital, capital expenditures, depreciation rates, rate base growth rates, allowed returns on capital, deemed capital structures, performance-based regulation, and settlement negotiations and expectations. Even where research analyst estimates of future EBITDA and/or earnings are available, the purchaser may have very different views about the future earning power of an asset. Indeed, the very idea of running an asset auction is to try and find the purchaser who will take the most aggressive view of an asset's future earning power which will be reflected in purchase price.

Stale-Dated Data

Even were an observer to have first-hand knowledge of all the assumptions a purchaser made about the future financial position of a regulated asset and could properly conclude what returns the purchaser expected from the acquisition, the issue of how long such a transaction should be influential as a precedent remains. For example, Fortis Inc.'s acquisition of Terasen took place in February 2007 making it now more than five years since the transaction closed. While that may not seem like a long period of time, much as happened in Canada's economy and financial markets since then (including the 2008-2009 credit crisis and market crash) and financial market and economic conditions have changed since then. In addition, it has been over nine years since Fortis acquired Aquila Networks and roughly 11 years since B.C. Gas acquired Centra Gas and AltaLink Management acquired TransAlta Utilities' transmission system.

Whatever might have been said about purchaser-expected acquisition ROEs back then, it would properly not apply today. There is no reason transactions undertaken in circumstances so different from today should be thought to speak to investor-expected returns today. Indeed, this point was acknowledged by the Alberta Utilities Commission:

> "… there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009."[29]

[29] AUC Decision 2009-216, 2009 Generic Cost of Capital, page 79.

Mistake

There is also the possibility, of course, that regulated asset purchasers may determine after the fact that they overpaid for the acquisition. Purchasers often re-evaluate their acquisition assumptions and results and may realize after closing that the cost of capital was higher than originally understood, the acquired asset may underperform (potentially resulting in write downs) or the purchaser may realize that its required returns were too low. It is not reasonable that such a purchaser (and other owners of regulated assets) should be penalized by third party-assumed ROE expectations.

Survivorship Bias

Acquisition price-to-book multiples suffer a serious survivorship bias. The survivorship bias is found in the vast graveyard of unsuccessful regulated asset bidders unavoidably excluded from any acquisition price-to-book analysis. They are excluded, of course, because as unsuccessful bidders no one knows what the unsuccessful bidders were prepared to pay to acquire the regulated assets – other than that they would likely have paid less than the successful bidders. Only price-to-book values from acquisitions concluded by successful bidders, that is, the "survivors" of the various sales processes, can be known or referenced.

Survivorship bias is a problem because each regulated asset bidder uses a unique set of expected and acceptable return assumptions in its bids. Even if they were determinable, it cannot be said that the winner's expected or acceptable returns[30] are the same as, or are somehow reflective of,

[30] As already demonstrated, however, even in the case of successful bidders it is not possible to know their expected returns on equity.

those of the other, unsuccessful bidders. Unsuccessful bidders may be unsuccessful because their acceptable return thresholds are substantially higher than those of the successful bidders. That information is simply not knowable.

Therefore, it would be unjust to impute the successful bidder's acquisition valuations on the numbers of unsuccessful bidders. Of course, it would be equally unjust to impute successful bidder valuations on those utilities which did not participate in regulated asset sales processes.

### *Market Required Returns & Investing Abroad*

#### Private Equity & Pension Fund Investing

Energy infrastructure is an attractive asset class for private equity which is attracted to the long-term, stable, cash flowing nature of energy infrastructure assets. As important capital market participants with interest in energy infrastructure assets, the returns on equity that private equity seeks for such assets are indicative of market required returns and should be taken into consideration as a "back-check" when setting allowed ROEs for regulated assets.

Because private equity recognizes the long life of energy infrastructure assets and associated cash flows, their return on equity targets with respect to energy infrastructure assets (including pipelines) are lower than for other asset classes and generally run in the order of a minimum of 15% to 20%.

Like private equity, Canadian pension funds are very interested in energy infrastructure assets. Canada's major pension funds have all signaled keen interest in growing their energy infrastructure investment portfolios. In discussions with the major Canadian pension funds, I understand they look for energy infrastructure investment returns on capital in the order of a minimum of 7.5% to 8.5% with returns on equity in the range of 10.0% to 12.0%. These target returns apply to investments in Canada as well as investments abroad. Again, like private equity, as important capital market participants with interest in energy infrastructure assets, the returns on capital pension funds seek for such assets are indicative of market required returns and should be taken into consideration as a "back-check" when setting allowed ROEs for regulated assets.

**Pension Fund Foreign Investment**

Canadian pension funds have been very active investing in energy infrastructure assets outside Canada. Table 5 summarizes select international infrastructure investments made by Canada's major pension funds**.**

Table 5 – Select Pension Fund Non-Canadian Infrastructure Investments

| **Asset** | **Description** | **Location** | **Purchase Price** | **Pension Fund / (Acquired Interest)** |
|---|---|---|---|---|
| Puget Energy | Natural gas distribution, electricity distribution and generation | Washington, U.S. | $6.7 billion (including $3.2 billion assumed debt) | • CPPIB[1]<br>• AIMCo<br>• bcIMC |
| Express/Platte Pipeline System | Petroleum export pipeline | U.S. | $1.2 billion | • Teachers (33.3%)<br>• OMERS (33.3%) |
| National Grid gas network | Natural gas distribution | England and Scotland | $7.25 billion | • Teachers (25%)<br>• OMERS (25%) |
| Northumbrian Water Group | Water supply and wastewater services | Southeast England | $615 million[2] | • Teachers (25%) |
| Scotia Gas Networks PLC | Gas distribution company with 74,000 kms of gas mains | UK | n/a | • Teachers (25%)<br>• OMERS (25%) |
| CLH | 3,800 km refined petroleum product pipeline with 6.3 million cubic meters of storage | Spain | n/a | • AIMCo (n/a) |

| Asset | Description | Location | Purchase Price | Pension Fund / (Acquired Interest) |
|---|---|---|---|---|
| Sutton and East Surrey Water | Regulated drinking water utility with 3,400 kms of water mains and 9 treatment plants | England | n/a | • AIMCo (n/a) |
| Thames Water | Related water and waste water utility – 31,000 kms water mains, 66,000 kms sewage lines and 349 treatment works | Greater London and South East England | n/a | • AIMCo (n/a) |
| Gassled | Offshore gas transport infrastructure | Norway | $3.2 billion | • CPPIB (10.8%) |
| Grupo SAESA | Regulated electricity transmission and distribution company – over 700,000 customers | Chile | n/a | • AIMCo (50%_<br>• OTPP (50%) |
| Open Grid Europe GmbH | Longest regulated supra regional gas transmission network in Germany – 12,000 kms pipeline | Germany | €3.2 billion | • bcIMC (consortium includes other foreign parties – ownership structure not disclosed) |

(1) Group ownership interest is just under 50%. Individual ownership positions not disclosed.
(2) Purchase price of 25% interest acquired by Teachers.

The Puget Energy acquisition is particularly noteworthy. The transaction closed on February 6, 2009 and involved a consortium led by Macquarie Infrastructure Partners, the Canada Pension Plan Investment Board, and British Columbia Investment Management Corporation and also included Alberta Investment Management Corporation and two other Macquarie affiliates.

Puget Energy is Washington's largest energy utility with over 1.0 million electric and just over 0.7 million natural gas customers and is regulated by the Washington Commission. As part of the acquisition, the consortium invested $300 million in Puget Energy to support its ongoing construction program and obtained credit facilities of over $2.0 billion to, among other things, help fund Puget's capital expenditure program. The consortium committed to support Puget

Energy's plans to spend over $5 billion over the five years following the acquisition to meet anticipated energy supply needs and delivery infrastructure requirements of the utility. Puget Energy estimated it would need more than 1,300 average-megawatts (aMWs) of new electricity supply by winter 2014-15 with an additional 1,300 aMW by 2025.

In the last settled Puget Energy general rate case (January 2007) prior to the acquisition, the Washington Commission allowed a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4% for both of Puget Energy's electric and gas utilities.[31]

Pension fund investment activity in energy infrastructure outside Canada demonstrates the competition for capital which Canadian regulated energy infrastructure businesses face. Capital is not border constrained. Canadian capital can and does leave the country to invest in energy infrastructure assets, including rate regulated, cost-of-service assets. Canadian assets compete for that capital with non-Canadian assets and, consequently, must offer competitive rates of return to attract capital on reasonable terms and conditions.

### *Conclusion*

In light of Canadian current and prospective capital market conditions, market required returns on capital for energy infrastructure assets, and opportunities for investments of comparable risk at attractive rates of return in Canada, the U.S. and elsewhere, I believe FEI's requested return on equity of 10.5% on a deemed equity component of 40% is consistent with current capital market

[31] Source: The C Three Group, "*2007 State Regulatory Benchmarks of US Electric and Gas Utilities - Third Edition*", June 2007, Atlanta, Georgia.

conditions, would be viewed by the financial market as more representative of FEI's true cost of capital, and would be fair and reasonable in the context of such conditions.

# Appendix F

# EVIDENCE OF MS. KATHLEEN C. MCSHANE, MBA

# TESTIMONY

**ON**

# COST OF CAPITAL

**FOR THE**

# FORTISBC UTILITIES

Prepared by

**KATHLEEN C. MCSHANE**

August 2012

# TABLE OF CONTENTS


| | | Page No. |
|---|---|---|
| **I.** | **INTRODUCTION AND SUMMARY OF CONCLUSIONS** | **1** |
| | A. INTRODUCTION | 1 |
| | B. SUMMARY OF CONCLUSIONS | 1 |
| **II.** | **FAIR RETURN STANDARD** | **8** |
| **III.** | **STAND-ALONE PRINCIPLE** | **10** |
| **IV.** | **RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND RETURN ON EQUITY** | **11** |
| **V.** | **THE BENCHMARK UTILITY** | **14** |
| | A. PURPOSE OF BENCHMARK UTILITY | 14 |
| | B. CHOICE OF BENCHMARK UTILITY | 15 |
| **VI.** | **TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS SINCE 2009** | **17** |
| **VII.** | **CAPITAL STRUCTURE FOR FEI AS BENCHMARK BC UTILITY** | **34** |
| | A. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION | 34 |
| | B. BUSINESS RISK OVERVIEW | 38 |
| | C. BUSINESS RISK RANKING BY UTILITY SECTOR | 43 |
| | D. BUSINESS RISK OF THE BENCHMARK UTILITY FEI | 48 |
| | E. BOND RATINGS AND CREDIT METRICS | 56 |
| | F. CHANGES IN ALLOWED CAPITAL STRUCTURE RATIOS FOR CANADIAN UTILITIES | 62 |
| | G. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE | 63 |

| | | | |
|---|---|---|---|
| **VIII.** | **FAIR ROE FOR FEI AS BENCHMARK BC UTILITY** | | **65** |
| | A. | IMPORTANCE OF MULTIPLE TESTS | 65 |
| | B. | DISTINCTION BETWEEN MARKET AND BOOK VALUES FOR FAIR ROE DETERMINATION | 70 |
| | C. | SELECTION OF COMPARABLE UTILITIES | 72 |
| | D. | EQUITY RISK PREMIUM TESTS | 76 |
| | E. | DISCOUNTED CASH FLOW TEST | 109 |
| | F. | COMPARABLE EARNINGS TEST | 113 |
| | G. | ALLOWANCE FOR FINANCING FLEXIBILITY | 117 |
| | H. | FAIR RETURN ON EQUITY FOR BENCHMARK BC UTILITY | 119 |
| **IX.** | **DEEMED CAPITAL STRUCTURE AND DEEMED DEBT MATTERS** | | **120** |
| | A. | CONTEXT | 120 |
| | B. | APPLICABLE CIRCUMSTANCES FOR A UTILITY TO UTILIZE A DEEMED CAPITAL STRUCTURE WITH A DEEMED DEBT | 120 |
| | C. | APPROPRIATE BASIS TO CALCULATE A DEEMED INTEREST RATE (LONG AND SHORT-TERM) FOR A UTILITY WITHOUT THIRD-PARTY OR NON-ARMS LENGTH DEBT | 123 |
| | D. | TERM OF BOND FOR DEEMED INTEREST RATE | 123 |
| | E. | APPROPRIATE CREDIT SPREAD FOR A BENCHMARK LOW RISK UTILITY | 124 |
| | F. | DEEMED CAPITAL STRUCTURE AND CREDIT SPREADS | 125 |
| | G. | APPROPRIATE PORTIONS OF SHORT-TERM AND LONG-TERM DEBT IN THE DEEMED CAPITAL STRUCTURE | 125 |
| | H. | APPROACH TO DETERMINING A DEEMED SHORT-TERM INTEREST RATE | 127 |
| **X.** | **GENERIC METHODOLOGY OR PROCESS FOR DETERMINING ROE AND EQUITY RATIO FOR BC UTILITIES** | | **128** |
| **XI.** | **GENERIC COMPANY-SPECIFIC MATTERS** | | **132** |
| | A. | EFFECTIVE INCOME TAX RATES | 132 |
| | B. | SIZE | 134 |
| | C. | CONTRIBUTED ASSETS | 136 |

# I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

## A. INTRODUCTION

My name is Kathleen C. McShane and my business address is One Church Street, Suite 101, Rockville, Maryland 20850. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, pipelines and telephone companies in more than 200 proceedings in Canada and the U.S., including the British Columbia Utilities Commission ("BCUC" or "Commission"). My professional experience is provided in Appendix G.

On February 12, 2012, the BCUC issued Order G-20-12, which initiated the Generic Cost of Capital ("GCOC") Proceeding. In Order G-47-12, dated April 12, 2012, the Commission issued its Final Scoping Document. In Order G-72-12, issued June 1, 2012, the BCUC set out the final filing requirements for the GCOC proceeding. I have been requested by the FortisBC Utilities ("FBCU")[1] to provide an expert opinion on various cost of capital matters contained in the Final Scoping Document and final filing requirements in Order G-72-12.

## B. SUMMARY OF CONCLUSIONS

My principal conclusions are as follows:

1. The allowed return must meet all three requirements of the fair return standard: comparable returns, financial integrity and capital attraction. The fair return extends to all components of the return, including the allowed capital structure, and return on equity (or "ROE"), that is, the overall return allowed must satisfy the fair return standard.

[1] FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), FortisBC Energy (Whistler) Inc. ("FEW") and FortisBC Inc. ("FBC").

2. The economic principle guiding the fair return is the opportunity cost principle. The opportunity cost of capital represents the expected return foregone when the decision is made to commit capital to an alternative investment of comparable risk. It represents the return that investors require to commit capital to a specific investment and the cost to the firm of attracting and retaining capital. Satisfying the fair return standard means allowing a return commensurate with the opportunity cost of capital.

3. Satisfying the comparable return requirement of the fair return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, and the small number of Canadian utilities with equity market data.

4. The capital structure and the fair ROE are inextricably linked. The fair ROE for a specific utility cannot be estimated independently of its capital structure, a fair ROE is a function of capital structure.

5. With regard to the benchmark BC utility:

   a. The purpose of designating a utility as the benchmark is partly for efficiency, i.e. to be able to assess factors that are common to all utilities in a single process, and partly to provide a foundation to ensure that the allowed returns of all affected BC utilities appropriately reflect their relative business risk.

   b. In light of these objectives, the Commission should designate a specific utility as the benchmark utility.

c. The benchmark utility represents the point of reference against which other utilities can be compared. The designated benchmark utility need not be the lowest business risk utility.

d. FEI is the logical choice to serve as the benchmark BC utility.

e. My recommendations for capital structure and fair ROE are premised on FEI as the benchmark BC utility.

6. With respect to broad cost of capital trends since the end of the oral portion of the 2009 Application ("2009 Application") which bear on the fair return:

a. Risks to the global financial system, as assessed by the Bank of Canada, are as high in mid-2012 as they were at the end of 2009.

b. There has been a material reduction in long-term Government of Canada bond yields. This decline largely reflects a confluence of factors, including deterioration in the global economic outlook, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, investor flight to quality, i.e., away from riskier assets including equities, and a decreasing global pool of safe haven assets. The reduction in long-term Government of Canada bond yields since the end of the oral portion of 2009 Application has little, if any, correlation with trends in the market cost of equity.

c. Although the absolute level of yields on long-term A-rated Canadian utility bonds has declined, the spread between those yields and the yield on long-term Government of Canada bonds is somewhat higher than it was at the end of the oral portion of the 2009 Application. The somewhat higher recent spreads indicate that investors view the risk associated with

A-rated utility bonds to be no less than at the end of the oral portion of the 2009 Application.

d. As of mid-2012, the level of the equity markets is little changed from the end of the oral portion of the 2009 Application, equity market volatility is similar and investor confidence levels are lower. Equity market indicators point to a higher current market cost of equity than at the end of the oral portion of the 2009 Application. In combination with the decline in long-term Government of Canada bond yields, the equity market risk premium is even higher.

e. The persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields make it difficult to construct an ROE automatic adjustment mechanism that would successfully capture changes in the utility cost of equity.

f. My estimate of a fair ROE for the benchmark BC utility is based on the premise that the allowed ROE will remain unchanged for at least three years. As a result, my equity risk premium tests are based on forecasts of long-term Government of Canada bond yields for 2013-2015.

7. With respect to capital structure, the analysis of the factors relevant to capital structure lead to my conclusion that FEI's current deemed common equity ratio of 40% should be viewed as the lower end of a reasonable range. Specifically:

a. The common equity ratio for FEI, the benchmark BC utility, should, in conjunction with the returns allowed on the various sources of capital, provide the basis for debt ratings in the A category.

b. The allowed common equity ratio should be compatible with FEI's business risk. The level of business risk, in the aggregate, to which FEI is exposed is no lower, and may be somewhat higher, than when it was last assessed in 2009. In the context of the trend in business risk, FEI's current deemed 40% common equity ratio remains at the lower end of a reasonable range, consistent with my assessment in the 2009 Application.

c. FEI's credit metrics at the current capital structure remain weak for its rating and are weaker than both its Canadian and U.S. peers, with which it competes for capital.

d. Moody's has strengthened its capital structure guidelines. FEI's current allowed common equity ratio is no longer within an investment grade rating category.

e. There have been a number of increases in allowed common equity ratios for FEI's Canadian utility peers since the oral portion of the 2009 Application. The across-the-board increase by the Alberta Utilities Commission ("AUC") was based on changed capital market conditions and credit metrics considerations, not changes in business risk of the specific utilities. The AUC's rationale for the increase would have been equally applicable to FEI, supporting, at a minimum, the retention of FEI's current 40% deemed common equity ratio.

8. The fair return on equity for FEI as the benchmark BC utility was estimated at 10.5%, based on a 40% common equity ratio, and reflects the following:

a. The recommended return on equity is based on the results of equity risk premium, discounted cash flow and comparable earnings tests.

b. A forecast 30-year Government of Canada bond yield for 2013-2015 of 4.0%.

c. The application of three separate equity risk premium tests.

d. The application of several models of the discounted cash flow ("DCF") test to a sample of U.S electric and gas utilities, as well as to a sample of Canadian utilities.

e. The addition to each of the market-based equity risk premium and DCF tests of a minimum 0.50% allowance for financing flexibility, sufficient to notionally allow a utility to maintain the market value of its investment at a small premium to book value.

f. The application of the comparable earnings test to a sample of relatively low risk unregulated Canadian firms.

g. The results of the tests, as summarized in Table 1 below:

**Table 1**

| **Cost of Equity Test** | **"Bare-bones" Cost of Equity** | **Financing Flexibility Adjustment** | **Return on Equity** |
|---|---|---|---|
| **Risk Premium Tests:** | | | |
| Risk-Adjusted Equity Market | 9.0% | 0.50% | 9.5% |
| Discounted Cash Flow-Based | 9.6% | 0.50% | 10.1% |
| Historic Utility | 10.5% | 0.50% | 11.0% |
| **Discounted Cash Flow Test** | 9.4% | 0.50% | 9.9% |
| **Comparable Earnings Test** | N/A | N/A | 11.5% |

h. The specific weight to be given the comparable earnings test versus the market-based (equity risk premium and discounted cash flow) tests is largely a matter of judgment. The comparable earnings test is, in my opinion, entitled to significant weight. When preponderant weight is given to the market-based tests, the fair ROE for the benchmark BC utility, i.e., FEI, is approximately 10.5%.

i. Alternatively, should only the market-based tests be relied upon (equity risk premium and discounted cash flow), a reasonable allowance for financing flexibility is 1.0%, reflecting the mid-point of a range of the minimum 0.50% described above to 1.50%. The upper end of the range represents full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures. The alternative approach also supports a fair ROE on the book value of common equity for FEI as the benchmark BC utility of 10.5%.

9. In the limited scenarios where a deemed cost of long-term and/or short-term debt may be warranted, I recommend that the Commission continue to address the appropriate cost on a case-by-case basis. There is no "one size fits all" cost that should be determined by means of an interest automatic adjustment mechanism.

10. There is no generic methodology or mechanism that can be used to set each utility's ROE and common equity in relation to the benchmark BC utility's ROE and common equity ratio. Each utility should be afforded the opportunity to tender and support the evidence it determines to be supportive of its requested capital structure and equity risk premium relative to the benchmark BC utility.

## II. FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[2] which are echoed in numerous regulatory decisions across North America, including the Commission's *2009 ROE Decision*.[3] A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

The legal precedents make it clear that the three requirements are separate and distinct. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard, specifically:

> The Commission Panel accepts the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other.[4,5]

---

[2] The principal seminal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

[3] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision*, December 16, 2009, page 15, hereafter referred to as *2009 ROE Decision*.

[4] BCUC, *In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, Decision,* March 2, 2006, page 48, hereafter referred to as *2006 ROE Decision*.

[5] The AUC recognized that the requirements of the fair return standard are separate and distinct:

> The Commission notes with approval the following description by the ATCO Utilities of how the three factors or criteria of the fairness standard are assessed:
>
> In the ATCO Utilities' view, the assertion that the three-part test is "simply three ways of looking at the same thing" fails to recognize the critical fact that there are differing tests which help to "triangulate" a Fair Return. Each may have greater or lesser relevance depending upon the economic landscape upon which the tests are conducted. The frailty of reliance on only a single leg of the three legged stool for stability and

Further, as the Federal Court of Appeal held in *TransCanada PipeLines Ltd. v. National Energy Board et al.*, [2004] F.C.A. 149, the required rate of return must be based on the cost of equity. The impact on customers of any rate increases cannot be a factor in the determination of the cost of equity capital.[6]

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy. An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to necessary expansion and innovation, potentially degrading the quality of service or depriving existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if a utility is not provided the opportunity to earn a fair return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services to its customers. In this context, it also bears noting that the lowest possible return is not an appropriate test, as the Commission has recognized:

> As for the JIESC's lowest cost argument, the Commission Panel shares the view of the NEB, which recognized that "lowest possible" was not the appropriate test when it stated, at page 25 of its RH-2-94 Decision on generic cost of capital:
>
> > "Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio possible."[7]

---

reliability of the result over changing economic conditions should be obvious. (Alberta Utilities Commission, *2009 Generic Cost of Capital, Decision 2009-216*, November 12, 2009, page 28)

[6] The Commission accepted this principle in 2006 ROE Decision, page 8, stating: "In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital." In BCUC, *An Application by Pacific Northern Gas Ltd. (PNG-West and Granisle) for Approval of 2006 Rates, Reasons for Decision*, August 21, 2006, page 25, the Commission stated that it "agrees with PNG that 'affordability' is not a test under the Act or the relevant case law and that it is a vague, relative and potentially shifting concept."

[7] BCUC, *2006 ROE Decision*, page 8.

## III. STAND-ALONE PRINCIPLE

Under the stand-alone principle:

> a utility is regulated as if the provision of the regulated service were the only activity in which the company was engaged. The cost of providing utility service and rates for provision of that service are to reflect only the expenses, capital costs, risks and required returns associated with the provision of regulated service (National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited, RH-R-1-2002, Review of RH-4-2001 Cost of Capital Decision*, February 2003, page 25).

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. Adherence to the stand-alone principle ensures that the focus of the determination of a fair return is on the use of capital, i.e., their opportunity cost, not the source of the capital. The opportunity cost of capital reflects the return that could be earned if that capital were invested in an alternative venture of similar risk.

The stand-alone principle, a cornerstone of Canadian utility regulation with a history dating to at least 1978,[8] and has been respected by virtually every Canadian regulator, including the BCUC, in setting both regulated capital structures and allowed rates of returns on equity.[9]

---

[8] Public Utilities Board of Alberta, *In the Matter of The Alberta Gas Trunk Line Company Act*, Decision C78221, December 21, 1978, pages 19-27.

[9] The stand-alone principle has been recognized by the BCUC by adopting capital structures and ROEs for the individual utilities it regulates that reflect the risks of those utilities, rather than the risks of their intermediate or ultimate parents, e.g., *2006 ROE Decision* and *2009 ROE Decision*.

## IV. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND RETURN ON EQUITY

The economic principle guiding the fair return is the opportunity cost principle. The opportunity cost of capital represents the expected return foregone when a decision is made to commit capital to an alternative investment of comparable risk. It represents the return investors require to commit capital to a specific investment and the cost to the firm of attracting and retaining capital. Satisfying the fair return standard means allowing a return commensurate with the opportunity cost of capital.

A utility's overall cost of capital represents the weighted average cost of the various sources of capital that it uses to finance its rate base assets. The weights represent the proportion of each source of funds used to finance the rate base assets and the cost of each source of funds represents what the company must pay for each type of capital it uses, including debt and common equity.

For utilities that are regulated on an original cost rate base, as is typical in Canada, including BC, and the U.S., in most cases, the cost of debt is an embedded cost, or weighted average of the costs that were determined at the time the debt was issued.

The utility cost of equity is a forward-looking cost, which, in accordance with the opportunity cost principle articulated above, represents the return that an equity shareholder expects to earn on an equity investment. It also represents the return that an equity investor requires in order to commit equity funds to or retain equity funds in an equity investment. From the perspective of the firm, it represents the cost that must be paid in order to attract and retain equity funding.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business and the political/regulatory operating environment that together determine the probability that future returns (including the return on and of the capital invested) to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm.

The cost of capital is also a function of financial risk. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Financial risk refers to the additional risk that is borne by the common equity shareholder because the firm is using debt to finance a portion of its assets. The capital structure, comprised of debt and equity, can be viewed as a summary measure of the financial risk of the firm. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises. As a result, the cost of equity, and thus the fair ROE depends on the capital structure.

There are effectively three approaches that can be used to determine the fair return. The first two approaches entail separate determinations of capital structure and return on equity. The third approach establishes an overall allowed rate of return without separately specifying the capital structure and return on equity.

The first approach either accepts the utility's actual capital structure for regulatory purposes or deems a capital structure that does not necessarily equate the total (fundamental business, regulatory and financial) risk of the "subject" regulated company to those of the proxy companies used to estimate the cost of equity. If, at the subject utility's actual or deemed capital structure, its total (business and financial) risk is higher or lower than that of the proxy companies, the proxies' estimated cost of equity needs to be adjusted upward or downward to arrive at the cost of equity of the specific utility.

The second approach assesses the utility's fundamental business and regulatory risks, and then establishes a capital structure that will equate its total risk with that of the proxy companies. This approach permits the application of the proxy companies' cost of equity without adjustment for differential total risk.

The third approach establishes the overall return (combining capital structure, cost of debt and cost of equity) for proxy companies and applies that overall return to the subject company, adjusted as warranted for differences in total risk between the subject utility and the proxy companies.

All three approaches have been taken by regulators in Canada. The first approach has been used by the BCUC, the Ontario Energy Board (OEB),[10] and the Régie de l'énergie du Québec (Régie).[11] The second approach has been used by the AUC (and its predecessor)[12] and the National Energy Board (NEB).[13] The third approach has also been utilized by the NEB in setting the allowed return on rate base for Trans Québec and Maritimes Pipelines Inc.[14]

The three approaches are equally valid as long as the overall return, i.e., the combination of capital structure and return on equity in the first two approaches, satisfies all three fair return requirements.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard.

---

[10] The Ontario Energy Board historically awarded different returns on equity and capital structures for Enbridge Gas Distribution, Natural Resource Gas and Union Gas.

[11] The Régie has awarded different capital structures and returns on equity for Gazifère, Gaz Métro and Hydro Québec Distribution and Transmission.

[12] Alberta Energy and Utilities Board, *Generic Cost of Capital*, *Decision 2004-052,* July 2, 2004, Alberta Utilities Commission (AUC), *2009 Generic Cost of Capital*, *Decision 2009-216*, November 12, 2009 and AUC, *2011 Generic Cost of Capital*, *Decision 2011-47*, December 8, 2011.

[13] National Energy Board, *Reasons for Decision, Cost of Capital*, *RH-2-94*, March 1995

[14] National Energy Board, *Reasons for Decision*, *Trans Québec and Maritimes Pipelines Inc.*, *RH-1-2008,* March 2009.

## V. THE BENCHMARK UTILITY

### A. PURPOSE OF BENCHMARK UTILITY

The objective of specifying a benchmark utility is to have a point of reference against which the regulator can compare other utilities under its jurisdiction for the purpose of setting their allowed returns (capital structure and ROE) without conducting a "from first principles" cost of capital proceeding for each one.[15] A "from first principles" proceeding entails a comprehensive review of capital market and economic conditions and the application of the various traditional tests for estimating the fair return on equity. By designating one utility as the benchmark, the Commission can conduct a single "from first principles" cost of capital proceeding, from which it can establish an appropriate common equity ratio and ROE for that benchmark utility. Those two parameters, common equity ratio and ROE, then become the benchmarks for the remaining utilities' allowed common equity ratios and ROEs.

The designation of one utility as the benchmark utility is partly a matter of efficiency, i.e., it avoids frequent reassessment of factors that are common to all utilities.[16] In addition, it provides a means of ensuring that all the utilities subject to the jurisdiction of the Commission are awarded overall returns that appropriately reflect their business risk relative to the benchmark utility, and, in turn, relative to each other.

Given both objectives, it makes most sense to designate a specific utility as the benchmark utility, rather than to rely on a hypothetical construct or hypothetical utility as the benchmark. By designating a specific real utility as the benchmark, that utility's business risks can used as a

[15] When comparable companies are initially selected for the purpose of the estimating a "benchmark" ROE, the concept of "benchmark utility" is *per force* a hypothetical construct, inasmuch as the estimated benchmark return reflects the composite of the risks of the selected companies, each of which, individually, has different characteristics. The resulting benchmark return is applicable to an actual utility, designated as the benchmark utility, which has specific risk characteristics that provide a single tangible foundation for making inter-utility comparisons.

[16] In the 2009 Application, FortisBC Inc. summarized the advantages of a benchmark (cited by the Commission in the *2009 ROE Decision*) as (1) cost savings to the Commission and to Intervenors in avoiding additional, unnecessary hearings; the evidence related to economic outlook and capital market conditions need not be presented nor heard more than once; (2) a consistent approach to economic outlook and capital market conditions, considered with reference to expert evidence gathered at a single point in time; and (3) and greater consistency with respect to ROE determinations for individual utilities from a common base.

baseline for assessing the relative risks of the other utilities in the jurisdiction. The concept of a hypothetical utility is too ambiguous to serve as a meaningful yardstick for the purpose of comparing business risks of utilities. It is not feasible to delineate the "generic" business risk characteristics of a hypothetical utility, be it a "low", "average" or "high" business risk utility, to an extent that would permit specifying what capital structure and ROE should apply to the hypothetical utility.

Every utility has unique business risk characteristics that are a function of: (1) the utility sector in which it operates; (2) the nature and age of its assets; (3) the geographic characteristics of its service area; (4) the economic characteristics of its service area; (5) its customer profile; (6) the political landscape; and (7) the regulatory framework under which it operates. The specifics of these broad factors interact to define an individual utility's aggregate market/demand, competitive, operating, supply and regulatory risks. While it might be fair to conclude that, as a general proposition, an electric transmission utility is a "low business risk" utility compared to other utilities operating in other sectors, it would still be necessary to identify and understand a particular electric transmission utility's specific circumstances in order to specify what the appropriate capital structure and ROE would be for that utility. In sum, it is not practical to determine an appropriate capital structure and fair ROE for a fictitious utility.

## B. CHOICE OF BENCHMARK UTILITY

The benchmark utility is simply the entity that serves as the standard or point of reference against which other utilities can be compared. The utility designated the benchmark utility need not be the lowest business risk utility in the province. It is no more difficult to subtract percentage points of equity or basis points of incremental equity risk premium from the ROE or the equity ratio of the benchmark utility than it is to add them.

The utility designated as the benchmark against which other utilities will be compared should preferably be a large, well established entity, with a relatively diverse geographic, customer and asset base, and no exceptional risk characteristics. Ideally, the designated benchmark utility will have market data that will provide an independent capital market assessment of its risks and return requirements.

FEI is the logical choice to serve as the benchmark BC utility. FEI is the largest investor-owned utility in British Columbia, is one of the largest gas distribution utilities in the country, and has a relatively diverse geographic, customer and asset base. It has no exceptional business risk characteristics that are likely to make comparisons with other BC utilities problematic. Although FEI's equity is not publicly traded, its debt is rated by two debt rating agencies, providing some independent capital market assessment of its overall business and financial risks, albeit from a bondholder's perspective.[17] Further, its business risks and the trends in those risks have been extensively and comprehensively assessed by the Commission in multiple proceedings.

FEI is currently part of the FortisBC Energy Utilities' Common Rates, Amalgamation and Rates Design Application, which, if it is approved and it proceeds, will result in an amalgamation of, and postage stamp rates for, FEI, FEVI and FEW. The proposed amalgamation does not invalidate designating FEI as the benchmark BC utility, as comparisons with other BC utilities can be made based on the characteristics of FEI pre-amalgamation for purposes of establishing their cost of capital by reference to the benchmark utility. In addition, FEI pre-amalgamation can be used as the benchmark utility for establishing the cost of capital for FEI Amalco, should amalgamation proceed. Whether FEI Amalco should be designated the benchmark utility (if amalgamation proceeds) can be resolved in a future proceeding.

The analysis that follows determines an appropriate capital structure and fair return on equity for FEI pre-amalgamation as the benchmark BC utility.

[17] Although bondholders and equity shareholders would consider the same business risks (and financial risks), the bondholders not only have a prior claim on the assets and earnings of the company, but also may benefit from protective covenants in the bond indentures. As a result, it would be incorrect to assume that the equity risks of two regulated companies with A rated debt are the same.

## VI. TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS SINCE 2009

This section addresses broad trends in cost of capital since the oral portion of the 2009 Application that ended October 1, 2009. In simple terms, the purpose of this section is to compare the current state of, and risks in, the markets where the costs of the various forms of capital are determined compared to the end of the oral portion of the 2009 Application. It is also intended to provide an appreciation of the protracted nature of the recovery from the global financial crisis and economic recession and of the recurrent bouts of capital market turbulence in the intervening 2¾ years.

In brief, as of the end of June 2012:

1. The systemic risks to the global financial system, as assessed by the Bank of Canada, are no lower than they were at the end of 2009.

2. Long-term Government of Canada bond yields are much lower than they were at the end of the oral portion of the 2009 Application. The reduction reflects a confluence of factors, including weak global economic conditions, central bank decisions to keep short-term interest rates low, investor risk aversion/flight to safety and a shrinking pool of risk-free assets. The trend in long-term Government of Canada bond yields is not indicative of the trend in the market cost of equity.

3. Yields on high grade Canadian corporate bonds have also fallen, largely tracking the decline in long-term Government of Canada bond yields. Spreads on high grade corporate bonds, including utility bonds, are slightly higher than they were at the end of the oral portion of the proceeding, indicating that the credit risk is not perceived to have declined.

4. Investor confidence is lower, equity market volatility is similar and the indicated market cost of equity is higher than it was at the end of the oral portion of the 2009 Application.

When the 2009 Application that culminated in the *2009 ROE Decision* (December 2009) commenced in May 2009, recovery from the global financial crisis was underway. Governments world-wide had already begun to take extraordinary steps, using both monetary and fiscal policy tools, to stabilize the capital markets and real economies. By the close of the oral portion of the 2009 Application:

1. The 10-year and 30-year Government of Canada bond yields, which had fallen to lows of approximately 2.6% and 3.3% respectively during the crisis, hovered around 3.3% and 3.8% at the beginning of October 2009. The September 2009 Consensus Economics, *Consensus Forecasts* anticipated that the 10-year Canada bond yield would increase to 3.9% over the next year, suggesting a forecast 30-year Canada bond yield of approximately 4.4%.

2. Spreads on investment grade long-term corporate debt (measured by the DEX Long Corporate Index) had sky-rocketed from close to 100 basis points in early 2007 to almost 400 basis points in December 2008. By the beginning of October 2009, the spreads had retreated to just over 200 basis points.

3. Spreads on the Bloomberg 30-year Canadian A-rated utility bond index, which had averaged approximately 95 basis points between 2003 and 2007, jumped to a peak of over 300 basis points in December 2008, recovering to around 145 basis points at the beginning of October 2009, corresponding to a yield of 5.3%.

4. The S&P/TSX Index had plummeted by 50% from late May 2008 to early March 2009. By October 1 2009, the equity market had recovered significantly, moving

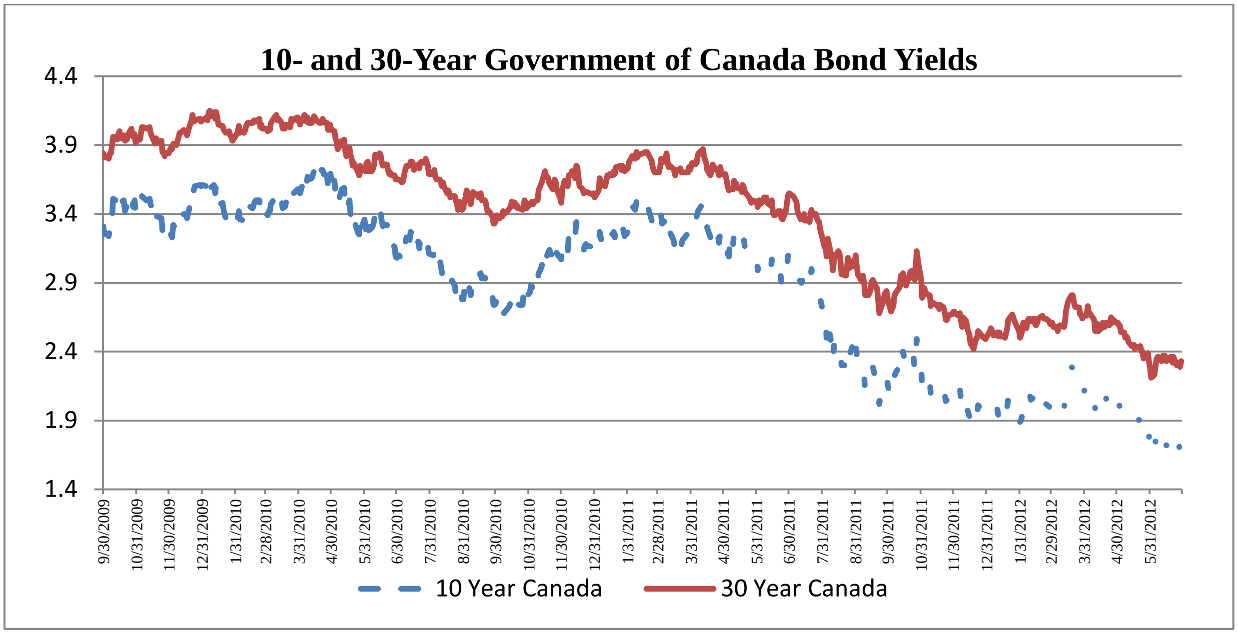
up almost 50% from the market trough. While the market was still over 25% below its 2008 peak, investor confidence had been on an upward trajectory.[18]

5. In early June 2009, Finance Minister Jim Flaherty announced that there were cautious signs that the Canadian economy, which had been in recession since 2008Q4, had stabilized. The September 2009 Consensus Economics, *Consensus Forecasts* anticipated positive real GDP growth in 2009Q4, and 2.4% growth in 2010.

From the close of the oral portion of the 2009 Application to April 2010, economic and financial market conditions in Canada continued to improve. Real GDP growth rates in Canada in 2009Q4 and 2010Q1 were 4.9% and 5.5% respectively. Between December 2009 and April 2010, long-term Canada bond yields hovered within a fairly narrow range of 3.9% to 4.2%. Chart 1 below shows the trends in 10-year and 30-year Government of Canada bond yields from the end of 2009Q3 to the end of June 2012.

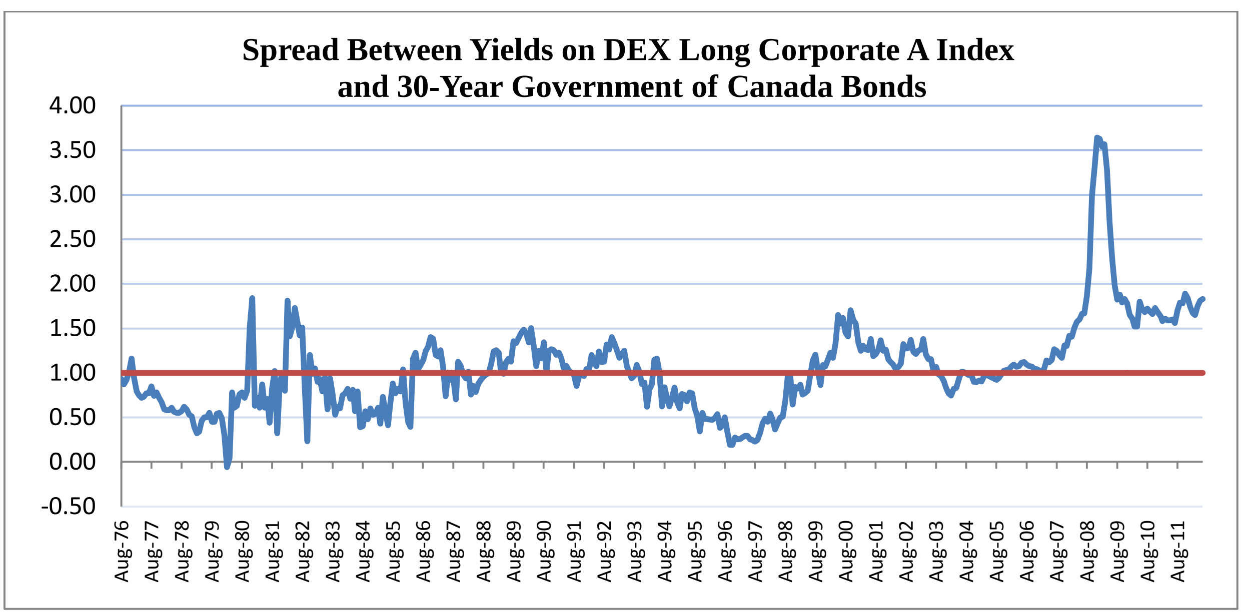
[18] As measured by the State Street Investor Confidence Global and North American Indices, which represent a quantitative assessment of investors' risk appetite, by measuring the actual and changing levels of risk contained in investment portfolios. The indices use "the aggregated portfolios of the world's most sophisticated investors, representing approximately 15 percent of the world's investable securities." The higher the index value is, the higher is investor confidence. A level of 100 is considered neutral, that is, it represents the level at which investors are neither increasing nor decreasing their allocations to risky assets. At the end of September 2009, the Global and North American index levels were 118 and 114 respectively, compared to 95 and 86 at the March 2009 equity market trough.

**Chart 1**




The spread between A-rated corporate and long-term Canada bond yields, having narrowed from the March 2009 peak of 360 to 190 basis points at the end of September 2009, contracted further. The spread reached 150 basis points at the end of April 2010, still well above the pre-crisis long-term average of less than 100 basis points. Chart 2 below sets out the spreads since 1976, the first year that 30-year Government of Canada bond yields were reported.

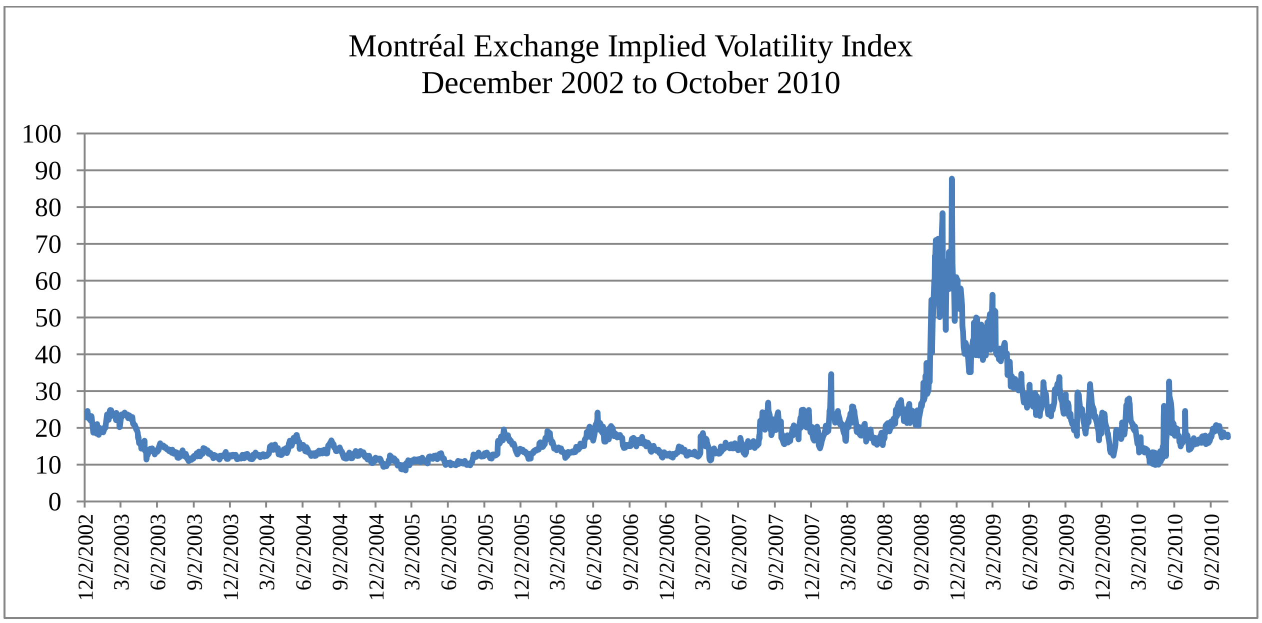
**Chart 2**



The corresponding spread between the Bloomberg 30-year A-rated utility bond index and the 30-year Canada bond had also contracted to approximately 130 basis points at the end of April 2010 (yield of 5.3%).

The equity market's recovery from its March 2009 trough had continued; the S&P/TSX Composite Index ended April 2010 approximately 20% below its 2008 peak. Expected equity market volatility, as measured by the Implied Volatility Index ("MVX"), had fallen to below pre-crisis average levels. Chart 3 below tracks the MVX from its inception in December 2002 until mid-October 2010.[19]

**Chart 3**




In May 2010, the sovereign debt crisis in Europe erupted. As the Bank of Canada noted in its June 2010 *Financial System Review*, "mounting concerns over fiscal sustainability in some euro-area member states and the exposure of global banks to sovereign risk erupted into a period of severe stress in international financial markets….". With Government of Canada bonds increasingly viewed as a safe haven alternative to U.S. Treasuries, a flight to quality exerted

---

[19] The MVX, introduced by the Montréal Stock Exchange in 2002, measured the market expectation of stock market volatility over the next month. It has been described as a good proxy of investor sentiment for the Canadian equity market: the higher the index, the greater the risk of market turmoil. A rising index reflects the heightened fears of investors for the coming month. The MVX was replaced by a somewhat different measure of implied volatility, called the S&P/TSX 60 VIX Index (VIXC), in October 2010, with historical data available from October 1, 2009. Similar to the MVX, the VIXC measures the market's expectation of stock market volatility over the next month.

downward pressure on Canada bond yields. Foreign investors acquired over $11 billion of Government of Canada bonds in May 2010,[20] helping to push long-term Canada bond yields to their lowest level since April 2009. At the end of May 2010, the yield on long-term Government of Canada bonds had fallen to 3.73%. The corresponding yields on the Bloomberg 30-year A-rated utility index had not changed materially (yield of 5.36%), pushing the A-rated utility/government bond yield spread to close to 165 basis points.

In its June 2010 *Financial System Review*, the Bank considered that, despite the momentum gained in the domestic and global economic recovery, the strengthening of the Canadian financial system and the fact that "bold policy actions taken by European governments and central banks, with international support, succeeded in heading off a full-blown crisis of confidence" the risks to Canadian financial stability had increased during the prior six months.

The strength in the Canadian economy during the first part of 2010 led the Bank of Canada to raise its target overnight rate three times between June and September (from 0.25% to 1.0%). However, in October 2010, the Bank of Canada announced that the economic outlook for Canada had changed and it expected growth to be more muted and the global recovery more gradual than previously forecasted. The changed economic outlook led the Bank of Canada to leave its target overnight rate (at a historically low 0.25%) unchanged, leaving significant monetary stimulus in place, and to conclude that "any further reduction in monetary policy stimulus would need to be carefully considered."[21] The Bank's statements led economists to conclude that there would likely be no further reduction in monetary policy stimulus before mid-2011.[22]

The relatively modest expected pace of growth reflected a combination of domestic factors (high household debt, which limits consumer spending) and international factors (e.g., the weak labour and residential real estate markets in the U.S., the strained balance sheets of banks and governments in Europe and related austerity programs in those countries, as well as constraints on export growth arising from a combination of tempered growth abroad, the high Canadian dollar and relatively weak productivity).

---

[20] Statistics Canada, *Canada's International Transactions in Securities*, May 2010.
[21] Bank of Canada, *Monetary Policy Report*, October 2010.
[22] Consensus Forecasts, *Consensus Economics*, November 2010.

In its December 2010 *Financial System Review*, the Bank of Canada again assessed the risks to the Canadian financial system, summing up those risks as follows:

1. Sovereign debt concerns in several countries;
2. Financial fragility associated with the weak global economic recovery;
3. Global imbalances;[23]
4. The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and
5. High leverage of Canadian households.

In all but one (potential for excessive risk-taking behaviour) of these categories, the Bank of Canada concluded that the risks to the Canadian financial system had risen over the previous six months. The nature of most of these risks, like the financial crisis itself, underscores the extent to which economies and capital markets globally are inter-twined.

With the Bank of Canada and other central banks maintaining their policy rates at historically low levels to stimulate economic growth, expectations that the global recovery would be protracted, along with rising risks from global sovereign debt, particularly in Europe and the U.S., and continued strong inflows into Canadian bonds,[24] Government of Canada bond yields drifting downward during the latter half of 2010, as did forecast yields.[25] At the end of 2010, the yield on the 30-year Government of Canada bonds was 3.5%; the corresponding yield on the Bloomberg 30-year A-rated utility index had also declined, to just below 5%.

[23] Global imbalances refer to imbalances between savings and investment in the world economies, as reflected in the significant distortions among current account balances, e.g., the large and persistent current account deficit in the U.S. and surplus in China.

[24] On average over the period 2009-2011 non-residents acquired government of Canada bonds at a rate of approximately $6.8 billion a month compared to approximately $1.0 billion per month in 2004-2006. At the end of 2011, foreign holdings were 26% compared to 13% in 2006.

[25] In May 2010, Consensus Economics, *Consensus Forecasts*, had anticipated that the 10-year Government of Canada bond would yield 3.8% and 4.2% three and twelve months forward; in November 2010, the corresponding forecasts had dropped to 2.8% and 3.3%.

As 2011 unfolded, despite headwinds from the ongoing sovereign debt vulnerabilities in Europe and the complications of a two-speed global economic recovery (i.e., modest growth in advanced economies versus emerging economies at risk of overheating), the Canadian economy appeared poised to advance at a steady, but modest pace. GDP growth in Canada in both the fourth quarter of 2010 and the first quarter of 2011 had been stronger than anticipated. From their third quarter 2010 low of 3.33%, long-term Canada bond yields gradually shifted upward, peaking in early second quarter 2011 at 3.87%. Similarly, the downward trend in forecast Canada bond yields reversed; the consensus forecast of the twelve-month forward 10-year Canada increased each month between November 2010 and April 2011.

In its June 2011 *Financial System Review*, the Bank of Canada noted decreased risk aversion in financial markets, evidenced by low yields on and record bond issuance in high yield (non-investment grade) debt, as well as low volatility in the equity markets. Nevertheless, in the Bank's view, risks to the financial system were still higher than in their six month earlier assessment, as the risk associated with global sovereign debt had edged higher and the risk associated with the low interest rate environment in advanced economies had increased with the growing popularity of riskier securities and strategies in both Canadian and global markets.

The decrease in investor risk aversion can be seen in the decline in yields on high yield Canadian bonds. High yield bonds are considered to have characteristics of both debt and equity, the latter due in large part to their higher default risk, higher sensitivity to the business cycle and closer connection to the underlying fundamental risks of the issuers than high grade corporate bonds. The yield on the DEX Overall High Yield Bond Index, designed to be a broad measure of the Canadian non-investment grade fixed income market, had fallen from 8.2% at the beginning of October 2009 to an average of 6.7% during 2011Q2.

By July 2011, market sentiment had started to shift. In the July 2011 *Monetary Policy Report*, the Bank of Canada pointed to several developments weighing on investor sentiment, including:

1. declines in equity market prices in both advanced and emerging economies during the prior three months in reaction to increasing uncertainty over the strength of the global recovery;

2. some deterioration in corporate credit markets;

3. a sharp reduction in bond issuance; and

4. shifting of capital into perceived safe haven assets and currencies, putting downward pressure on government bond yields in major advanced economies.

By the end of August 2011, 10-year and 30-year Canada bond yields had fallen to 2.5% and 3.1% respectively. The Bloomberg 30-year A-rated utility index yield had also declined (to 4.7%), but not as sharply. In contrast, the yield on the DEX Overall High Yield Bond Index, which had been yielding 6.5% in March and April 2011, had risen to 7.8%.

Over the next few months, a number of the risks with which the Bank of Canada had expressed concern in earlier reports were experienced. In its October 2011 *Monetary Policy Report*, the Bank of Canada referenced the acute fiscal and financial strains in Europe and concerns about the strength of global economic activity that had led to increased and significant financial market volatility, reduced business and consumer confidence, and an escalation of risk aversion. The increased volatility was triggered by a reassessment of the prospects for global economic growth, as well as heightened worries over debt sustainability in the euro area and uncertainty over the direction of fiscal policy in the United States. According to the Bank, the already negative tone in financial markets was exacerbated by numerous credit rating downgrades of sovereigns and global financial institutions. As the Bank noted, as a result, investment flows shifted toward safer and more liquid assets. Government bond yields in a number of advanced economies, where markets are most liquid and which are perceived to be better credit risks, had fallen sharply. At the same time, prices of riskier assets had declined significantly.

In its December 2011 *Financial System Review*, the Bank of Canada judged that the risks to the stability of Canada's financial system were high and had increased markedly over the past six months. In the Bank of Canada's assessment, over the prior six months, the risks associated with global sovereign debt and an economic downturn in advanced economies had risen, with the risks associated with global imbalances, Canadian household finances and the low interest rate environment unchanged.

By the end of 2011, 10-year and 30-year Government of Canada bonds were yielding 1.9% and 2.5% respectively.[26] With the core rate of inflation running at approximately 2.0% during 2011 and expected to average 2.0% over the longer-term,[27] the real yield on the 10-year Government of Canada bond was negative. Long-term A-rated utility bonds were yielding just over 4%. In contrast, the S&P/TSX Composite ended the year down more than 15% from its early year high. High yield Canadian bonds had continued to climb, reaching 9.5% at the end of September 2011 and ending the year at 9.1%.

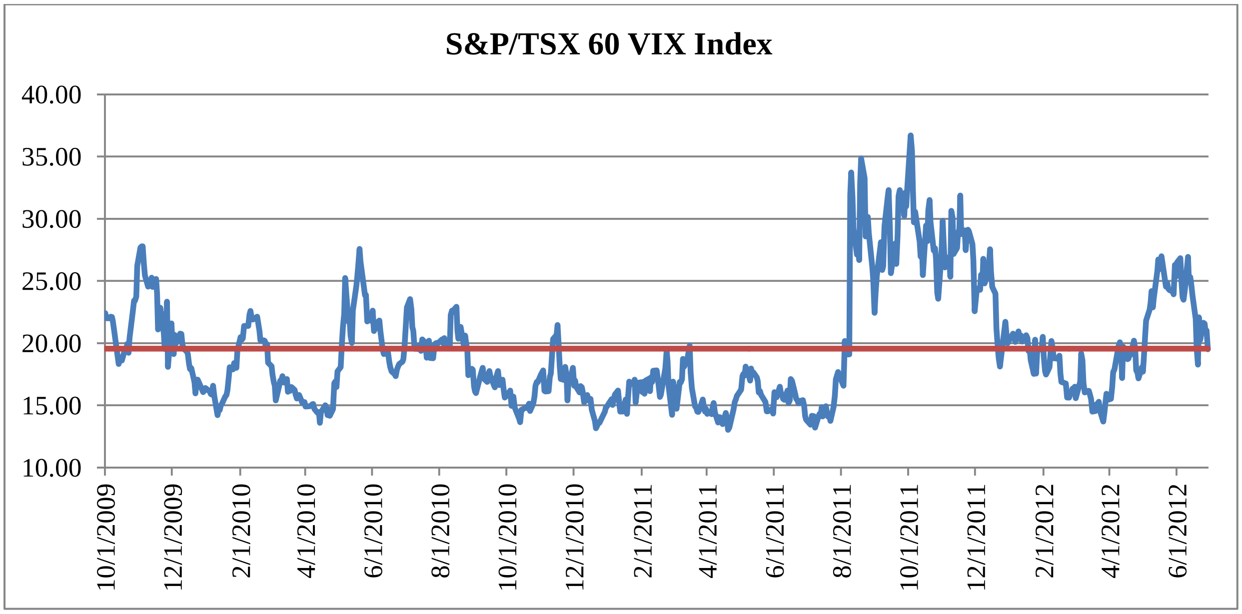
As Chart 4 below demonstrates, expected equity market volatility, as measured by the VIXC,[28] increased markedly in August 2011. On average during November 2011-January 2012, the VIXC was slightly more than 20% higher than during the corresponding period in 2009-2010.

[26] Forecasts of long-term Government of Canada bonds had also experienced another significant decline. From November 2010 to April 2011, the monthly 12-month forward consensus forecasts of 10-year Canada bond yields had gradually moved up from 3.3% to 4.0%. They then reversed course; by December 2011, the 12-month forward consensus forecast of 10-year Canada bond yields had declined to 2.7%. Of that 1.3 percentage point decline, 1.1 percentage points occurred between August and October 2011; it represents the largest two month change (positive or negative) observed since the inception of the *Consensus Forecasts* in 1990.

[27] Consensus Economics, *Consensus Forecasts*, October 2011.

[28] Chart 4 tracks expected volatility as measured by the S&P/TSX 60 VIX Index (VIXC) from October 1, 2009, the first day for which historical data are available.

**Chart 4**




In its January 2012 *Monetary Policy Report*, the Bank anticipated that growth in the Canadian economy throughout 2012 would be weaker than previously forecast, despite the better than anticipated momentum experienced during the second half of 2011. The weaker growth forecast was largely due to the continued deterioration in the global economy, resulting in further tightening of international financial markets and continued risk aversion. Economic indicators suggested that the euro area had entered into a recession in the fourth quarter of 2011 and the "deteriorating financial conditions, bank deleveraging, fiscal consolidation and large negative confidence effects" of this recession were expected to last well into 2012. The Bank found that, since the October *Monetary Policy Report*, investors had continued to shift toward safer and more liquid assets, resulting in yields on government bonds in Canada, Germany, the United Kingdom and the United States continuing to decline at the same time that spreads in some of the euro area's largest economies had risen, in some cases to post-euro record highs. Investor anxiety had also continued at high levels, resulting in continued market volatility in global markets.

The International Monetary Fund's *World Economic Outlook Update* released January 24, 2012 echoed the Bank of Canada's concerns, concluding that the global economic recovery is threatened by intensifying strains in the euro area and fragilities elsewhere and that financial conditions have deteriorated, growth prospects have dimmed and downside risks have escalated. The downside risks relate to the potential reduction in credit availability and output in the eurozone arising from sovereign and bank funding pressures, which is transmitted to the rest of the world, excessive fiscal tightening in the U.S. in the near term but failure to arrive at a credible fiscal consolidation strategy in the medium term, a hard landing in emerging economies, and intensified concerns about an Iran-related oil supply shock.

During the first quarter of 2012, there were signs of improvement in the global economy, e.g., an improving labor market in the U.S. and the provision of liquidity by the European Central Bank. Capital markets appeared to calm and risk aversion to moderate, only to be roiled again by a re-intensification of the eurozone sovereign debt crisis, focused on Greece, Spain and Italy.

The Bank of Canada's June 2012 *Financial System Review* noted that:

1. the global recovery remains modest, fragile and uneven, with economic momentum solid in Canada, growth in the U.S. continuing at a modest pace, but European economic activity expected to remain sluggish and growth in emerging markets having moderated;

2. the principal risk to domestic financial stability continues to stem from sovereign debt strains in the euro area;

3. the risks associated with high levels of household debt in Canada and a potential correction in the housing market are elevated and have not diminished since the Bank's last assessment in December 2011;

4. global current account imbalances continue to represent an important risk to the global financial system, although they have declined slightly and are expected to narrow further over the next several years. The Bank considered that the reason for their narrowing, i.e., deficient demand for imports in advanced economies due to contractionary fiscal policies and household deleveraging., which, in turn, is

leading to weak demand for exports from surplus countries and lower global economic growth;

5. the low interest rate environment continues to create incentives for risky behaviour (e.g., drive for yield, particularly by institutions with balance sheets under stress like pension funds and life insurance companies), with the potential for misallocation of credit and the mispricing of risk.

In summary, the Bank of Canada concluded that the systemic risks to the global economy and financial system are high and unchanged since its previous (December 2011) assessment. A review of each of the Bank of Canada's six-month *Financial System Reviews* indicates that the risks to the global economy and financial system rose in each assessment between December 2009 and December 2011, with no change between December 2011 and June 2012.

With increased economic uncertainty, investor risk aversion and global shifting of funds into the safe haven of a smaller pool of highly rated government bonds,[29] long-term Canada bond yields have fallen more than a full percentage point over the past 12 months, hitting a historical low of 2.21% on June 1, 2012. At the end of June 2012, the yield on long-term[30] Canada bonds stood at 2.33%.

High grade corporate bond yields have also been impacted by the smaller pool of highly rated sovereign bonds, as investors have sought relatively safe fixed income alternatives.[31] The end of June 2012 yield on the Bloomberg 30-year A-rated utility index was 3.92%. The corresponding spread with the long-term Government of Canada bond yield, at 160 basis points, was slightly

[29] After the United States and the United Kingdom, Canada is the largest non-eurozone economy with AAA sovereign debt ratings. The U.S. was downgraded to AA+ by Standard & Poor's in August 2011, but still has AAA ratings by Moody's, Fitch and DBRS. Despite the S&P downgrade, U.S. Treasury bonds continue to be regarded as a safe haven investment.

[30] As represented by the yield on the Government of Canada marketable bonds over 10 years Series V39062.

[31] The "flight to quality" arising from market conditions is exacerbated by demographic trends, i.e., the aging of the population, and a corresponding shift of investment into fixed income securities. As baby boomers have aged and the ratio of retirees to active workers in the U.S. has increased, there has been a "strong trend in mutual fund flows that suggests investors have begun earnestly diversifying their portfolios toward fixed-income products, in many cases away from equity funds." (Tom Roseen, Lipper Funds, March 1, 2012) Lipper reported that over the past three years mutual fund investors have invested almost $5 into fixed income funds for every $1 invested in equity funds. In the three years following the 2001/2002 equity market collapse, almost $15 was invested in equity markets for every $1 invested in fixed income markets.

higher than at the close of the oral portion of the 2009 Application. The higher spread indicates that investors view the risk associated with A-rated utility bonds as no less than at the end of the oral portion of the 2009 Application.

The current level of Canada bond yields reflects a confluence of factors, including deterioration in the global economic outlook, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, and investor flight to quality, i.e., away from riskier assets including equities. With respect to the last factor, with the numerous ratings downgrades of sovereign bonds that have taken place in the eurozone over the past two years, the supply of safe haven assets has shrunk,[32] and a scarcity value attributed to high grade sovereign bonds (including those of Canada, the U.S., the U.K. and Germany) that are viewed as least affected by the eurozone debt crisis.

Over the longer-term, 10-year Government of Canada bond yields are forecast to rise to more normal levels, as indicated in Table 2 below.[33]

**Table 2**

| Year | 2014 | 2015 | 2016 | 2017 | 2018-2022 |
|---|---|---|---|---|---|
| **Forecast 10-year Canada** | 3.6% | 4.2% | 4.5% | 4.6% | 4.7% |

Source: Consensus Economics, *Consensus Forecasts*, April 2012.

With an average historical spread between 30-year and 10-year Government of Canada bonds of 35 basis points, the corresponding longer term yield on 30-year Canada bonds is approximately 5.0%.

---

[32] Barclay's *Equity Gilt Study 2012* concluded that "An important reason for these low yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years." In its April 2012 *Global Financial Stability Report*, the International Monetary Fund found that "the number of sovereigns whose debt is considered safe is declining - taking potentially $9 trillion in safe assets out of the market by 2016 (roughly 16 percent of the projected total). These developments will put upward pricing pressures on the remaining assets considered safe."

[33] Consensus Economics issues long-term forecasts of key economic indicators, including the 10-year Government of Canada bond yield, twice a year, in April and October.

The recent downward trend in long-term Government of Canada bond yields has little, if any, correlation with trends in the market cost of equity. A comparison of equity market indicators points to a higher market cost of equity in mid-2012 versus at the end of the oral portion of the 2009 Application, and, due to the decline in long-term Government of Canada bond yields, an even higher equity market risk premium.

The VIXC averaged 23 during June 2012, slightly higher than the October 2009[34] average of 21 (Chart 4 above). High yield bonds, which as noted above, have both debt and equity characteristics, were yielding 8.4% at the end of June 2012, slightly above their 8.2% end of September 2009 level. As referred to above, Global and North American investor confidence levels at the end of June 2012 were well below the September 2009 levels.

While both the reported earnings and dividends of the companies that comprise the S&P/TSX Composite and the S&P/TSX 60 have increased materially since September 2009, at the end of June 2012, the two price indices were little changed from their September 2009 levels. As Table 3 below shows, the resulting index price/earnings (P/E) ratios were lower (and the dividend yields were higher) at the end of June 2012 than at the end of September 2009. The comparative earnings yields (E/P), the inverse of the P/E ratios, provide a rough guide to the direction in the market cost of equity over this time period. The forward E/P ratio of the S&P/TSX 60 has increased from approximately 5.2% to 7.8%, implying that the market cost of equity has risen since late 2009. With Government of Canada bond yields having declined significantly between late 2009 and mid-2012, the corresponding implication is that the equity market risk premium is higher currently than it was in late 2009.

[34] The first month for which there are data for the new S&P/TSX 60 VIXC.

**Table 3**

| | September 2009 | June 2012 |
|---|---|---|
| **S&P/TSX Composite** | | |
| Price Index | 11,395 | 11,597 |
| Earnings | $530.8 | $789.0 |
| Dividends | $314.4 | $365.8 |
| Trailing P/E | 21.5X | 14.7X |
| Dividend Yield | 2.8% | 3.2% |
| **S&P/TSX 60** | | |
| Price Index | 678 | 664 |
| Earnings | $38.5 | $48.0 |
| Dividends | $17.5 | $20.9 |
| Trailing P/E | 17.6X | 13.8X |
| Dividend Yield | 2.6% | 3.1% |
| Forward P/E [1/] | 19.1X | 12.6X |
| Forward Earnings Yield (E/P) | 5.2% | 7.8% |
| 10-year Canada Bond Yield | 3.3% | 1.7% |
| E/P less 10-year Canada Bond | 1.9% | 6.2% |

[1/] Forward P/E ratio estimated as market-value weighted average of the month-end prices of equities in the S&P/TSX 60 divided by I/B/E/S consensus forecast of earnings per share for next fiscal year (2010 and 2013).

Source: www.bankofcanada.ca, I/B/E/S from S&P, Research Insight, *TSX Review*.

As regards the cost of equity capital for utilities and the implication of the observed decline in long-term Canada bond yields, before the onset of the financial crisis, publicly-traded Canadian utility dividend yields generally tracked the long-term Government of Canada bond yield. On average from 1998-2007, the median dividend yield of the five major publicly-traded Canadian utilities[35] was, on average, 25% **lower** than the corresponding yield on the 30-year Government of Canada bond. Since the beginning of 2008, the ratio of utility dividend yields to long-term Canada bond yields has risen markedly. At the end of June 2012, the median Canadian utility dividend yield was approximately 60% **higher** than the 30-year Canada bond yield.[36]

[35] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. Excludes Valener Inc., as it was previously a limited partnership (Gaz Métro LP), which converted to a conventional corporation in September 2010. Hereafter referred to as the "five major publicly-traded Canadian utilities".

[36] The ratio of Canadian utility dividend yields to A-rated utility bond yields is also significantly higher than it was pre-crisis. At the end of June 2012, Canadian utility dividend yields were approximately 95% of A-rated utility bond yields, compared approximately 60% from March 2002 (the starting date of the Bloomberg 30-year Canadian A-rated utility bond index) to the end of 2007.

If the pre-crisis relationship between utility dividend yields and the yield on the 30-year Canada bond were still valid, at the end of June 2012 30-year Canada bond yield of 2.3%, the current Canadian utility dividend yield should be approximately 1.75% (75% of 2.3%). Instead, it is 3.7%.[37]

The observed change in the relationship between Canadian utility dividend yields (which represent a significant component of the cost of equity[38]) and long-term Government of Canada bond yields represents compelling support for the following conclusions:

1. The estimation of a fair ROE for the benchmark BC utility should be based on multiple tests, including tests which are not benchmarked to the long-term Government of Canada bond yield.

2. In the application of equity risk premium tests that are benchmarked to the long-term Government of Canada bond yield, the abnormally low level of recent and forecast long-term Government of Canada bond yields needs to be taken into account in the assessment of what constitutes an appropriate equity risk premium.

In light of the persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields, it would be, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.[39]

---

[37] Alternatively, based on the pre-crisis relationship, all other things equal, the observed 3.7% utility dividend yield would correspond to a 30-year Canada bond yield of approximately 4.9% (3.7%/0.75), rather than the much lower end of June 2012 yield of 2.3%.

[38] The utility cost of equity can be estimated as the sum of the expected dividend yield and the expected growth in dividends. For a utility with approximately industry average long-run growth potential, the dividend yield component can account for approximately one-half the total estimated cost of equity.

[39] In October 2010 and November 2011 the Régie implemented automatic adjustment formulas for Gazifère and Gaz Métro respectively that change the allowed ROE by 75% of the change in forecast 30-year Government of Canada bond yields and 50% of the change in long-term A-rated utility bond yield spreads. Gaz Métro's allowed ROE for 2012 was set at 8.9%, reflecting a forecast long-term Government of Canada bond yield of 4.0% and a utility bond yield spread of 150 basis points. Based on the most recent forecast and spreads, Gaz Métro's 2013 allowed ROE will be close to a full percentage point lower than in 2012. The trend in Canadian utility dividend yields indicates

In developing a fair ROE for the benchmark BC utility, I have proceeded on the premise that the ROE adopted in this proceeding will be in place for at least three years. On that basis, in the application of equity risk premium tests, I have developed forecasts of long-term Government of Canada bond yields that encompass the three-year period 2013-2015, not solely 2013.

# VII. CAPITAL STRUCTURE FOR FEI AS BENCHMARK BC UTILITY

## A. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION

The principles which should be respected in the determination of an appropriate capital structure for a utility include (1) the stand-alone principle; (2) compatibility with business risk; (3) the ability to attract capital on reasonable terms and conditions; (4) maintenance of financial integrity; and (5) comparability of returns. Principles (3) to (5) represent the three requirements of the fair return standard, and reflect the inter-dependence between capital structure and ROE.

1. Stand-alone Principle

   As indicated in Section III above, the stand-alone principle means that the allowed return on capital should reflect only the risks and required returns associated with the provision of regulated service. This principle extends to both capital structure and ROE, and the combination thereof.

2. Compatibility of Capital Structure with Business Risk

   The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. At a high level, because debt financing magnifies business risk, all other things equal, the higher the business risk of the utility, the higher a reasonable common equity ratio would be. As the Commission pointed out in its *2009 ROE Decision*,

---

the opposite: higher Canadian utility dividend yields in mid-2012 than when the Régie rendered its decision for Gaz Métro in November 2011 point to an increase in the cost of equity for Canadian utilities since late 2011.

"The assessment of risks has significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

3. Attraction of Capital and Financial Integrity

A reasonable capital structure for the benchmark utility, FEI, in conjunction with the returns allowed on the various sources of capital, should permit the utility to attract capital on reasonable terms and conditions and to maintain its financial integrity.

To be able to attract debt capital on reasonable terms and conditions and to maintain its creditworthiness, a reasonable capital structure for the benchmark BC utility, FEI should provide the basis for stand-alone investment grade debt ratings in the A category.[40] Debt ratings in the A category ensure that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities have an obligation to provide service on demand, and must maintain access to the capital markets to fulfill that obligation.

The importance of credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in the Baa/BBB[41] category) faces a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with Baa/BBB ratings can be closed out of the Canadian debt market at times, particularly at the longer end (20-30 year term) of

[40] The Commission has accepted that a credit rating in the A category is appropriate for FEI. In the *2009 ROE Decision*, page 15, the Commission stated that "It also agrees with Terasen that the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody's." The AUC explicitly considers that a rating in the A category is an appropriate objective in setting the regulated capital structures for Alberta utilities (AUC, *Decision 2009-216*, page 88, and *Decision 2011-474*, pages 31 and 35).

[41] Baa is the Moody's medium grade ratings designation; BBB is the corresponding DBRS and Standard & Poor's designation.

the debt market.[42] Utilities, including FEI, are principally financing long-term assets. Thus, the Company needs to maintain the financing flexibility required to be able to access debt with long-term maturities in both strong and weak capital market conditions.[43]

Insufficient equity for the level of business risk and/or inadequate credit metrics (which largely reflect the debt/equity structure and cash flows from returns on and of capital) are factors that could result in a downgrade of a utility's debt rating. If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of any additional debt that the company needs to raise, but will also affect all of the utility's outstanding debt. An increase in the cost of new debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus Baa/BBB rated debt varies with market conditions, but ratings in the Baa/BBB category can be materially more costly to ratepayers than ratings in the A category.[44] As the global financial market crisis demonstrated, capital markets can deteriorate rapidly, and spreads can widen dramatically. Although the market for lower rated credits in Canada has been growing, it is still relatively small. Institutional investors continue to face limits on the proportion of Baa/BBB rated debt they are allowed to hold in their portfolios or are precluded from investing in Baa/BBB rated debt. The

[42] During the period June 11, 2008 to January 29, 2009 inclusive there was not a single issuer without at least one "A" credit rating who was able to issue long-term debt on any terms in the public Canadian debt market.
[43] Although the market for lower rated credits has been growing, for the period January 2010 – June 2012, of the \$140 billion of new corporate debt in Canada reported by RBC Capital Markets (*Credit Weekly*, various issues), only 20% was for issues rated in the BBB rating category or lower. Of the 108 issues that were rated in the BBB rating category or lower, only eight were for a term longer than 10 years.
[44] Over the past 15 years, the average spread between yields on long-term BBB-rated and A-rated corporate debt in Canada has been 75 basis points. During the same period, the spread has been as high as 200 basis points.

relatively small size of the Canadian market for Baa/BBB rated debt and the limitations on the ability of Baa/BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

FEI, as well as other BC utilities, are competing for capital in a global market in which there may be unprecedented requirements for energy infrastructure capital, particularly in the power sector. In its 2011 *World Energy Outlook*, the International Energy Agency estimated that between 2011 and 2035 close to $38 trillion in global cumulative energy infrastructure investment is required, including $9.5 trillion in the gas industry ($2 trillion in transmission and distribution) and $16.9 trillion in the electricity industry.[45] The Conference Board of Canada estimates that investment in electricity infrastructure alone in Canada over the period 2011 to 2030 will be close to $348 billion.[46]

To compete successfully for the capital it needs, that is, to continue to be able to attract capital on flexible terms and conditions, FEI requires credit metrics (which reflect the combination of capital structure and ROE) that are competitive with those of its peers.

The maintenance of debt ratings in the A category, which depends partly on an appropriate capital structure, and partly on adequate cash flows from earnings and return of capital, should allow FEI, the benchmark BC utility, to attract debt capital on reasonable terms and conditions.

4. Comparability of Returns

As it is the overall return which must meet the comparable returns requirement of the fair return standard, it is the composite of a regulated utility's financial

[45] International Energy Agency, *2011 World Energy Outlook*, October 2011, Figure 2.20.
[46] Conference Board of Canada, *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure*, February 2012. The INGAA Foundation estimated that approximately $205 billion of investment was required in North American natural gas midstream (including mainline transmission, laterals, gathering lines, compression, storage and processing) infrastructure from 2011 to 2035, with an additional $46 billion investment in the natural gas liquids and oil midstream sector (INGAA Foundation, *North American Natural Gas Midstream Infrastructure Through 2035: A Secure Energy Future: Executive Summary*, June 2011).

> parameters, including the adopted capital structure and allowed returns on capital, that need to be comparable to the returns of similar risk companies.
>
> Comparability of the regulated utility's overall return to its peers, including capital structure, is not only a legal requirement, it is necessary in order to be competitive in the capital markets. FEI competes for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies, both within Canada and globally. The achievement of comparable returns requires recognition of the financial parameters, including capital structure, of FEI's comparable risk peers, including regulated companies throughout North America.

## B. BUSINESS RISK OVERVIEW

As noted above, a utility's business risk comprises the fundamental characteristics of the business (e.g., market/demand, competitive, supply and operating factors) and political/regulatory risk that together determine the probability that the utility's future returns (including the return on and of capital) will fall short of the returns that investors expect and require.

Utility business risks have both short-term and longer-term aspects. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term business risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term business risks that are of primary concern to the investor.

Because utilities are generally regulated on the basis of annual revenue requirements, the longer-term risks are sometimes downplayed, essentially on the grounds that the regulatory framework will allow the regulator to provide compensation to investors as the risks materialize, through higher ROEs and/or assurance of return of capital. This premise may not hold. If the utility is losing customers and throughput, competitive limits on regulated prices may constrain a utility's ability to earn higher returns or recover the invested capital when the risk materializes. Second, utility assets are long-lived. No regulatory panel can bind its successors and thus guarantee that investors will be compensated in the future for risks as they materialize.

The capital structure needs to recognize long-term business risks. As the business risks materialize, the utility may find it more difficult to raise new debt capital. Consequently, the common equity component effectively provides a cushion in the event of deterioration of access to capital. This should not be interpreted to mean that business risks are only reflected in capital structure. Nor should it be interpreted to mean that the long-term aspects of business risk are captured only in capital structure with short-term variability in earnings captured solely in the ROE. Both the capital structure that is appropriate for a particular utility and the required rate of return on equity incorporate elements of short-term and long-term business risks. Investors look at the risks of a utility in the aggregate in assessing what return they require from a utility equity investment; they do not assign short-term risks to ROE and long-term risks to capital structure.

The primary categories of utility business risk are:

1. Market/Demand Risk

   Market demand risks relate to the size of the market for the utility's services and the ability of the utility to capture market share. Market demand risks reflect the demographics of the service area, including the diversity of the economy, economic growth potential, geography/weather, customer concentration, customer spending patterns, customer mix, and customer preferences.

2. Competitive Risk

Competitive risk refers to the business risk arising from competition for customers and load due to the existence of alternatives to, or potential for substitutes for, the utility's services. Competitive risks would include a utility's cost structure; e.g., a high cost structure has the potential to lead to customer and load attrition and to the development of lower cost alternatives.

3. Supply Risk

Supply risk relates to the physical availability of the commodities required to deliver service to end use customers. Supply risk includes exposure to supply interruption, and thus, for gas utilities, the degree of reliance on a single supply basin and/or pipeline and the availability of storage. For electric utilities, supply risk also reflects the diversity of supply sources, including owned generation and purchased power.

4. Operating Risk

Operating risk encompasses the physical risks to the revenue generating capabilities of the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather.

5. Political Risk

Political risk relates to the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal Rights.[47]

[47] S&P has stated: "Governments change, government policies change, views on ownership change, economic circumstances change… Politics by definition is populist, expedient, and capricious, and creditors should not dismiss the likelihood of change." (Standard & Poor's, *Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc*., October 20, 2005) While S&P's statements were made in a specific context, i.e., the risk related to future financial support by the province of Ontario of its Crown utilities, the references to the potential for political change as it relates to utility risk are more broadly applicable.

6. Regulatory Risk

Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in regulatory philosophy, government policies, including energy policy, and underlying fundamental business risk factors, e.g., the competitive environment.

The assessment of business risk is an inherently qualitative exercise, not amenable to quantification.[48] There is no recognized methodology for isolating individual business risk factors and quantifying the corresponding required increment of common equity or ROE. Different categories of business risk can be identified and ranked in order of importance, but the order ranking may differ among utilities. It is also possible to assign each risk a number or level (e.g., "low", "medium", "high") to represent the potential likelihood of the risk being experienced and a weight to represent the potential severity of the risk should it be experienced. However, the numbers or levels assigned to convey "how much riskier" would be inherently subjective, as would be weights to denote potential severity.

Further, the various categories of business risks are inter-related[49] and inter-dependent. A change in one category or type of business risk can have a subsequent impact on another type or category of business risk. To illustrate, high market/demand risk may lead to significant customer loss, in turn, raising the utility's cost structure, leading to higher competitive risk. Alternatively, high supply risk may lower customer demand, increasing market/demand risk.

[48] The NEB stated, for example, in RH-2-94, page 24, "The Board has systematically assessed the various risk factors for each of the pipelines but has not found it possible to express, in any quantitative fashion, specific scores or weights to be given to risk factors. The determination of business risk, in our view, must necessarily involve a high degree of judgment, and is best expressed qualitatively." The AUCs' predecessor similarly acknowledged that the level of utility business risk is a subjective concept (EUB, Decision 2004-052, page 35).

[49] The NEB noted in its *Reasons for Decision*, *TransCanada Pipelines Limited*, *RH-2-2004*, *Phase II*, April 2005, "The various forms of risk are related, and the boundaries between them are subjective. What one party may consider a source of market risk may be viewed by another as part of competitive risk."

Finally, the exercise of creating a risk by risk "scorecard" would not comport with the manner in which investors evaluate business risk. Investors appraise business risk on an overall aggregate basis, not by relying on a risk by risk checklist.

While business risk cannot be quantified, a qualitative business risk analysis does allow the assessment of both the relative total business risk among utilities and the trends in business risk. However, while necessary, neither a relative business risk assessment nor an assessment of the trends in a particular utility's business risk, in isolation, is sufficient to determine a reasonable capital structure. The business risk assessment must be used in conjunction with other factors, both qualitative and quantitative, such as capital structures adopted by peer companies, debt rating agency guidelines, actual credit metrics, debt ratings and trends in the credit environment in order to judge what constitutes a reasonable capital structure and, ultimately, how the overall risk of a utility compares to its peers.

Moreover, while trends in business risk are an important consideration in assessing whether there should be a change in a utility's regulated capital structure, other trends, including changes in capital market conditions, credit metrics, and industry practice, are also important considerations. An increase in common equity ratio may be warranted, even if there has been no change in business risk if, for example, investors have become more risk averse and require more conservative financial parameters for a given level of business risk. An increase in equity ratio may also be warranted if credit metrics are weakening due to diminished cash flows.[50]

[50] For example, the AUC's 2% across-the-board increase to the common equity ratios of the Alberta utilities in *Decision 2009-216* (confirmed in *Decision 2011-474*) was not due to changes in business risk. Rather, the increase reflected reductions in ROEs and income tax rates over time that would otherwise lead to a deterioration in credit metrics as well as the AUC's conclusion that it:

> must also consider that the events that drove the original [financial] crisis will be factored into investors' perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors' and ratepayers' interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions. (AUC, *Decision 2009-216*, page 90).

## C. BUSINESS RISK RANKING BY UTILITY SECTOR

### 1. Overview

In its Minimum Filing Requirements ("MFR"), the Commission requested a business risk ranking and rationale by industry sector, specifying electricity, natural gas and alternative energy service providers.

It is virtually impossible to rank the three sectors generically, largely because the utilities that constitute the "electricity sector" in Canada (as well as in the United States) span a wide range of business risk. In Alberta, for example, the electricity industry has been restructured, with separate entities or divisions of entities performing different functions. Only electricity transmission and distribution remain regulated; generation has been deregulated. Electricity distributors in Alberta no longer have the obligation to acquire power (either by building generating capacity or contracting for power) and, although they retain the default supplier obligation, they have exited the retail function and have designated other firms as their default supplier. The electricity industry has also been restructured in Ontario, where each of the functions (transmission, distribution and generation) is regulated separately, with regulation of the last limited to specific generating facilities of Ontario Power Generation. In that jurisdiction, while electric distribution utilities retain the retail function, they no longer bear the obligation to acquire power on behalf of their end use customers; the cost of purchased power is flowed through to customers. Similarly, in Québec, the electricity industry has been restructured, with the transmission and distribution functions separately regulated by the Régie; the generation function is not regulated by the Régie. In contrast, in the remaining provinces, including British Columbia, the electric utilities are predominantly vertically integrated, operating all three functions on a regulated basis.

Given the different electricity industry models in use in Canada, rankings are provided for electric transmission, distribution and vertically integrated utilities, as well as for natural gas distribution and alternative energy service providers. In regard to the last, the ranking applies only to British Columbia, since alternative energy service providers are not regulated in other provinces in Canada. The rankings provided below, from lowest business risk to highest business risk are intended to be "generic", i.e., based on fundamental characteristics that are generally common to utilities in each category. They should not be interpreted to mean, for example, that every utility categorized as an electric distribution utility is of lower business risk than every gas distribution utility, or that every gas distribution utility is of lower business risk than every vertically integrated utility. While it might be fair to conclude that, as a general proposition, electric distribution is an "average business risk" sector compared to other sectors, without analyzing a particular electric distribution utility's specific circumstances, it would not be reasonable to conclude that the specific electric distribution utility is indeed an "average business risk" utility.

The extent to which the "generic" relative risk sector rankings hold for individual utilities would be dependent on such factors as:

1. Energy policies in the regulatory jurisdiction.
2. The regulatory environment generally in the utility's service area.
3. The specific elements of the regulatory model to which the utility is subject.
4. The size, economic diversity and growth potential of the service area.
5. Customer mix and concentration.
6. Competitive environment.
7. Geography, which is a factor in the nature and extent of competition, as well as of operating risks.
8. In the case of vertically integrated utilities, the diversity of power supply and the specific technologies employed to generate electricity.

**2. Sector Rankings (Lowest to Highest Business Risk) and Rationale**

2.a <u>Electricity Transmission</u>

1. Electricity is required by every household and business for some applications. End uses of electricity are more diverse than for natural gas.

2. Although there is some bypass risk, electric transmission is the closet to a pure monopoly of the sectors ranked.

3. No commodity price risk.

4. Rate structures of electric transmission utilities provide for high degree of assurance of recovery of forecast annual revenue requirements.

5. Credit (bad debt) risk is relatively low, as transmission utilities typically recover revenues from highly rated entities (distribution utilities or an independent system operator).

6. Relatively low operating risk.

2.b <u>Electricity Distribution</u>

1. As with electricity transmission, electricity is required by every household and business for some applications. End uses of electricity are more diverse than for natural gas.

2. In some cases (e.g., Alberta and Ontario) there is no obligation to ensure an adequate supply of electricity, and no power purchase agreements. In Alberta, the electricity distributors do not purchase power at all. In Ontario, purchased power is a flow through cost, purchased from the Ontario Electricity System Operator and power costs are not subject to prudence review. Hydro Québec Distribution is responsible for acquiring a supply portfolio to meet demand which exceeds

commitments from the fixed price “heritage” supply and faces some risk of higher than forecast supply costs.

3. While not a pure monopoly, as there is some competition with alternative fuels, the distribution system is not likely to be duplicated. Competition with alternative fuels in Ontario and Alberta, as natural gas is the fuel of choice for heating load. More competition with natural gas in BC and Québec, where electricity prices are relatively low and electricity is almost exclusively generated from a renewable resource.

4. Higher volatility of revenues than electric transmission due to recovery of fixed costs in variable charges.

5. Higher exposure to economic downturn than electric transmission.

6. Relatively low operating risk.

2.c Natural Gas Distribution

1. More limited end uses for natural gas than for electricity.

2. Heating load generally a significant portion of throughput, for which there are substitutes, including solutions that are more technologically and economically feasible than were available historically.

3. Throughput is generally more weather sensitive than for electricity distribution utilities.

4. Industrial processes that use natural gas can frequently switch to other sources of energy.

5. As heating load oriented utilities, more exposure to declining throughput (due to factors such as smaller and more energy efficient homes and more energy efficient equipment) than electricity distributors.

6. With some exceptions (e.g., ATCO Gas), gas distributors retain responsibility for acquiring a gas supply portfolio; gas purchases are subject to prudence review.

7. As sellers and transporters of fossil fuel, may have more exposure than electricity distributors, particularly where electricity is produced by “green” energy sources, to impacts of environmental policies and regulations directed at reducing emissions and favoring clean and/or renewable energies as well as of consumer perceptions of natural gas as a fossil fuel.

8. Relatively low operating risk

2.d <u>Vertically Integrated Electric Utilities</u>

1. Electricity is required by every household and business for some applications. End uses are more diverse than for natural gas.

2. Vertically integrated utilities have the obligation to build, lease or contract for power to serve their customers. The construction of base load generation frequently has long lead times, the potential deferral of the recovery of significant financing costs until the plant goes into service, risk that the market may not have materialized when the plant is complete, and risk that construction costs may be disallowed.

3. Purchased power and fuel costs are subject to prudence review.

4. If generating plants are not operating, costs of obtaining replacement power may be borne by shareholders.

5. Generating plants are more likely to be substituted with, or bypassed by, a lower cost alternative power source or subjected to a competitive market than a distribution system.

6. A “typical” vertically integrated electric utility (i.e., one which generates the preponderance of the power that is sold to its native load) has approximately 45% to 50% of its rate base invested in generation plant, which is inherently more risky

from an operational standpoint than distribution or transmission assets. The extent to which that is the case depends on the technologies utilized (e.g., nuclear generation is more technologically challenging than hydroelectric generation).

7. Fossil fuel generating capacity is subject to higher environmental risks than distribution systems.

2.e BC Alternative Energy Service Providers

1. Typically start-up ("greenfield") operations without an established customer base.
2. May require non-traditional rate structures for the operation to be competitive and provide opportunity to recover invested capital due to "front end loaded" rate base.
3. Generally, a small customer base from which invested capital must be recovered.
4. Reliance on less established energy technologies to provide service.
5. Competition to install services with both conventional sources of energy and other alternative energy providers.
6. Small size is a dominant risk characteristic.

## D. BUSINESS RISK OF THE BENCHMARK UTILITY FEI

### 1. Purpose of Business Risk Analysis

In the *2009 ROE Decision*, the Commission increased FEI's deemed common equity ratio from 35% to 40%, having found that FEI's business risk had increased since the *2006 ROE*

*Decision*.[51] The section that follows represents my assessment of whether there have been any changes in FEI's business risk that would, in isolation, warrant a change in the deemed common equity ratio from the 40% approved in the *2009 ROE Decision*. Based on my assessment, the level of business risk, in the aggregate, to which FEI is exposed is at least as high as when it was last assessed in 2009.

### 2. Market/Demand and Competitive Risk

Market/demand and competitive risks are integrally related and thus are assessed together. Prices of natural gas have declined materially since the 2009 Application, due largely to a combination of the shale gas boom in North America and relatively weak economic conditions. Despite natural gas prices that are currently lower than in 2009, the market and competitive trends identified in the 2009 Application persist.

FEI's core business continues to be the residential and commercial space and water heating markets. Close to 90% of FEI's delivery revenue, or gross margin, is derived from the residential and commercial sectors, of which over 80% is from space and water heating applications. In the residential sector, which alone accounts for over 60% of the gross margin, new customer additions have declined significantly since their 2007 peak, and are expected to remain modest, consistent with minimal growth in housing starts over the longer term.

The new housing construction market continues to shift toward multi-unit dwellings; in 2011, close to two-thirds of all housing starts in British Columbia were multi-unit dwellings. The persistent trend in new housing construction toward multi-family units reflects affordability and space availability.

FEI's capture rate in new multi-unit dwellings has been, and continues, to be materially lower than in single family housing (approximately 30% versus 70%). The lower capture rates in

[51] The Commission also increased the benchmark utility ROE (applicable to FEI as the designated benchmark utility) relative to the level that would have been produced by the automatic adjustment mechanism terminated in the *2009 ROE Decision*. A thorough review of the *2009 ROE Decision* indicates that the increase in the benchmark utility ROE was not related to the increase in FEI's business risk, but rather to the Commission's conclusion that the automatic adjustment formula was not producing a fair ROE.

multi-unit dwellings largely reflect the fact that the energy choice is made by builders and developers, rather than the end user. Builders and developers focus more on the upfront capital costs of equipment installation and space considerations than on operating costs, or what it costs the end user at the burner tip. Builder and developer objectives continue to favour the installation of electric equipment over natural gas equipment.

FEI's per customer usage rates in the residential sector continue to fall. The persistence of declining usage rates is explained primarily by: (1) smaller and more energy efficient new single family homes; (2) more energy efficient replacement equipment in existing single family homes; and (3) the shift in the housing stock to multi-unit dwellings. FEI's estimates show that the usage rates of new residential customers is almost 50% lower than the usage rates of existing customers.

A comparison of the four provinces with large natural gas utilities shows that, in BC, natural gas has a materially smaller share of the residential market than in either Alberta or Ontario. Although BC is the second largest natural gas producing province in the country, natural gas has just under a 50% share of the residential market, compared to over 60% in Ontario, which produces relatively little natural gas. The market share of natural gas in the residential sector in Alberta, the largest natural gas producing province, is over 80%. While, in BC, electricity accounts for close to 45% of the residential market, in Alberta and Ontario, electricity has significantly smaller market shares.

**Table 4**

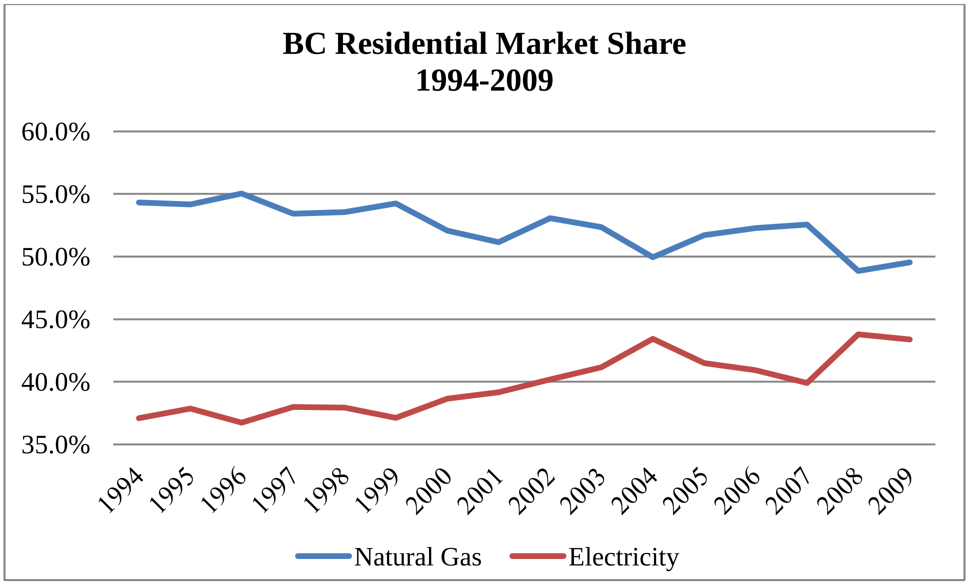
**Residential Market Share**
**Natural Gas and Electricity**
**(2009)**

| British Columbia | | Alberta | | Ontario | | Quebec | |
|---|---|---|---|---|---|---|---|
| Natural Gas | Electric | Natural Gas | Electric | Natural Gas | Electric | Natural Gas | Electric |
| 49.5% | 43.4% | 82.1% | 16.9% | 62.4% | 29.2% | 8.2% | 68.5% |

Source: Natural Resources Canada, Comprehensive Energy Data Base

Over time, in BC, the market share of natural gas in the residential sector has been on a gradual downward trend, while the market share of electricity has been rising, as shown in Chart 5 below.

**Chart 5**




Source: Natural Resources Canada, Comprehensive Energy Data Base

The relatively high market share of electricity in BC stems from the province's abundant hydroelectric resources, which has resulted in a relatively low cost source of electric generation, similar to Québec. For perspective, hydroelectric generation accounts for over 90% of the total electricity produced in both BC and Québec, compared to less than 5% in Alberta and approximately 20% in Ontario. Low embedded costs of heritage hydroelectric generation have resulted in low electricity prices in BC, and have helped foster a marketplace in which natural gas faces strong competition from electricity for its core business. Despite both lower commodity costs since 2009 and increased electricity rates in BC, the percentage differential between the operating costs of natural gas and electricity for a typical residential customer remains materially lower in BC than it is in either Alberta or Ontario. The much higher spread between electricity and natural gas prices in Alberta and Ontario is due to the two provinces' reliance on higher cost sources of generation and the determination of the price of power by market forces rather than embedded utility costs.

Operating cost differentials, which reflect commodity or power costs plus delivery costs, do not take account of the upfront capital costs of installation. Higher upfront installation costs of natural gas equipment than electric equipment significantly narrows the gap between electricity and natural gas prices in BC.

The competitive pressures on natural gas in BC that stem from the abundance of low cost hydroelectric resources and the evolving housing composition are amplified by energy policies. Designed to fight climate change, provincial energy policies and associated regulations promote reduced and more efficient energy use, discourage the use of fossil fuels, and promote the development and use of clean energy technologies and renewable resources. By the time of the 2009 Application, the province had introduced its 2007 Energy Plan and related legislation that committed to greenhouse gas ("GHG") emission reduction targets and imposed the carbon tax on fossil fuels, including natural gas. The policies and legislation have both direct and indirect impacts on the use of natural gas. The carbon tax directly raises the commodity price of natural gas. The carbon tax on natural gas was $0.50/GJ in 2008, and reached $1.50/GJ in 2012, where it will remain, pending the government's comprehensive review of the tax.

The less direct impact relates to altered customer perceptions of various forms of energy. Consumers are more likely to have a negative perception of natural gas, a fossil fuel, and a positive opinion of electricity produced by renewable hydroelectric resources.

Since the 2009 Application, there have been several energy policy related developments, the Clean Energy Act (2010), the Greenhouse Gas Reduction Clean Energy Regulation (2012), and the province's Natural Gas Strategy (2012). Among other things, the Clean Energy Act supports maintaining low electricity rates in the province, reduction of energy demand, development of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources. All of the provisions of the Clean Energy Act reinforce the competitive challenges to natural gas in FEI's core space and water heating markets. The subsequent Greenhouse Gas Reduction Clean Energy Regulation allows utilities to provide incentives to the transportation sector to adopt natural gas as an alternative to gasoline and diesel fuel, but does not encourage natural gas use in FEI's principal markets. While the regulation offers some upside demand potential, the transportation sector's contribution to FEI's delivery revenues over the next five years, based on the incentives available, is expected to be small. The Natural Gas Strategy released earlier this year recognizes the importance of natural gas to the BC economy, reinforces support for the use of natural gas in the transportation sector and espouses development of BC's natural gas reserves for export as LNG. The Natural Gas Strategy's support for natural gas, which the document refers to as a "transition fuel", does not extend to the use of natural gas in FEI's principal markets, space and hot water heating.

The adoption of renewable forms of energy in combination with new technologies for delivering the energy has continued to progress, not only on an individual customer basis, but also on a community basis. The increased community focus on reducing GHG emissions and energy efficiency is supporting a wider scale adoption of forms of energy and technologies that displace natural gas.

Notwithstanding the reduction in natural gas prices since 2009, the trends that have been creating downward pressure on FEI's throughput (which ultimately determines its ability to recover the invested capital) have continued. On balance, the market/demand and competitive risks to which FEI is exposed are no lower than they were in 2009.

**3. Supply Risk**

As noted above, supply risk entails both the physical availability of the commodity and the exposure of the utility to supply interruption. For a gas utility, the latter comprises the diversity of the infrastructure required to deliver the natural gas commodity to the load centres when it is required.

With respect to the former, the risk of insufficient physical natural gas supply has historically been low. The discovery of large shale gas reserves in northeastern BC is clearly a positive development. However, how much of that gas will flow to FEI's service area remains uncertain. Pipeline capacity from northeastern BC into Alberta, where the potential exists for significant natural gas demand, e.g., for the oil sands industry, has already been expanded. The development of offshore markets for LNG has the potential to move northeastern BC natural gas west for export rather than to FEI markets. With respect to infrastructure, there have been no material changes in the infrastructure available to ensure reliability of supply delivery apart from the Mt. Hayes peaking facility. FEI continues to depend heavily on a single pipeline, Westcoast, and has limited access to area storage facilities. Overall, FEI's gas supply risk, which was already relatively low, is somewhat lower than in 2009.

**4. Operating Risk**

FEI's operating risks relate to factors that can cause outages or leaks on the distribution system, including third-party damages, both accidental and intentional, equipment failure, pipeline corrosion, severe weather and natural disasters, which could result in material service disruptions or environmental liability. In contrast to utilities that operate systems in more benign geographic regions, FEI operates facilities in remote and rugged terrain, which are subject to damage from a variety of natural events (e.g., avalanches, landslides, forest fires). Although the utility carries insurance, there is no guarantee that all costs that might be incurred will be recoverable. Similar to other long-operating utilities, FEI's infrastructure is aging, which entails ongoing replacement to ensure maintenance of safety and reliability. FEI's capital replacement program depends on external resources, both skilled labour and materials, which are likely to be in demand by other utilities with similarly aging assets, creating potential cost pressures and forecasting risk. The operating risks that FEI faces have not changed materially since 2009.

**5. Political Risk**

Most of the key elements of political risk to which FEI is exposed have been outlined above in the context of market/demand and competitive risk. They comprise the energy and energy-related policies, legislations, regulations and decisions at both the provincial and local government levels that support reduction in natural gas usage, either by encouraging an overall reduction in energy usage or by supporting the displacement of natural gas by alternative forms of energy.

FEI also is subject to risk arising from First Nations rights. As at the time of the 2009 Application, uncertainty regarding the extent of aboriginal rights and title in BC continues. There is still an absence of treaties with most of the large number of recognized First Nations groups in BC. The obligation to consult with, and if necessary, accommodate First Nations' interests ultimately lies with the Crown, not with the utility. The issues related to First Nations rights and claims expose FEI to operational and regulatory uncertainty and as well as the risk of litigation.

Government has played, and continues to play, a significant role in triggering and reinforcing the trends that are putting downward pressure on FEI's throughput. The level of political risk faced by FEI is no less than that faced in 2009.

### 6. Regulatory Risk

FEI's regulatory model is based on a forward test year and comprises a number of deferral accounts that mitigate FEI's short-term forecast risk. The principal deferral accounts are related to the recovery of gas supply costs (Commodity and Midstream Cost Reconciliation Accounts) and of the variances between forecast and actual residential and commercial usage (Revenue Stabilization Adjustment Mechanism). Neither the basic regulatory framework nor the extent to which FEI's forecast risk is mitigated through deferral mechanisms has changed materially since 2009.

The principal change that has occurred since the 2009 Application relates to increased regulatory lag and uncertainty that stem largely from the changing energy environment, particularly for natural gas. More FEI activities, focused on new initiatives, are subject to regulatory oversight, entailing more frequent, protracted, and contentious proceedings. With the requirement that the Commission consider applications in the context of the province's energy policies, in particular the 2010 Clean Energy Act, the regulatory environment has become more complex and less predictable.

On balance, the regulatory risk to which FEI is exposed is no lower, and in some ways is higher, than in 2009.

### 7. Business Risk of FEI Relative to 2009

Despite the shale gas boom and lower commodity prices of natural gas, the principal trends in FEI's business risk that were identified in the 2009 Application have persisted. The level of business risk, in the aggregate, to which FEI is exposed is at least as high as when it was last assessed in 2009. Consequently, in the context of the trend in business risk, FEI's deemed 40% common equity ratio remains at the lower end of a reasonable range.

## E. BOND RATINGS AND CREDIT METRICS

Bond ratings or credit ratings are the credit rating agencies' opinion of the credit quality of individual debt obligations or of a debt issuer's general creditworthiness. Credit quality refers to the ability of the issuer to pay the interest and repay the principal on the loan when they are due. Bond ratings are an important determinant of the relative price (credit spread) an issuer will have to pay to obtain new debt.

Bond ratings are partly a function of credit metrics or credit ratios. Credit metrics are objective measurements of a firm's cash flows, earnings, debt leverage and interest coverage used to assess financial strength and credit risk.

For regulated utilities, the debt ratio (and its converse, the equity ratio) is, on its own, a key credit metric, and is a contributing factor to the magnitude of other critical credit ratios, as well as to the bond rating itself. An examination of debt ratings and credit metrics provides valuable insight into a utility's financial strength relative to its peers and into trends over time, and thus into the reasonableness of its capital structure.

FEI's debt is rated by DBRS and Moody's.[52] FEI's DBRS rating is A with a Stable trend; its Moody's debt rating is A3 for senior unsecured debentures with a Stable Outlook.[53] Since bond investors are more likely to focus on the lowest rating, it is appropriate to focus on the Moody's rating, which is only one notch from the Baa rating category (equivalent to the BBB category on the DBRS/S&P rating scales).[54]

In August 2009, Moody's adopted a new framework for rating electric and gas utilities world-wide.[55] The new ratings framework gives 50% weight to two factors that reflect regulatory risk, regulatory framework (25% weight) and ability to recover costs and earn returns (25% weight). The methodology also considers diversification (10% weight)[56] and financial strength and liquidity (40% weight). The financial strength and liquidity factors are divided into sub-categories with individual weights assigned to the sub-categories. The sub-categories and weights are: Liquidity (10%),[57] Cash from Operations (CFO) plus Interest/Interest, or CFO Interest Coverage (7.5%), CFO to Debt (7.5%), CFO less Dividends to Debt (7.5%) and Debt to Total Capital (7.5%).

---

[52] FEI's unsolicited S&P ratings were last confirmed in September 2010 and then withdrawn by S&P due to lack of market interest.

[53] FEI's senior secured rating, which applies only to $275 million of Purchase Money Mortgages that were issued over 20 years ago, is A1. The senior secured rating was raised from A2 in August 2009 as part of an industry-wide change, under which the debt rating agency widened the notching between the secured and unsecured debt ratings of investment-grade utilities to two notches. The change affected $90 billion of North American debt securities. For most utilities with senior secured securities, including FEI, the upgrades were a single notch.

[54] The Moody's Rating scale is as follows:

| **Rating** | **Rating Definition** |
|---|---|
| Aaa | Highest quality with minimal credit risk |
| Aa | High quality with very low credit risk |
| A | Upper medium credit with low credit risk |
| Baa | Medium grade with moderate credit risk; may possess certain speculative elements |
| Ba | Have speculative elements and are subject to substantial credit risk |
| B | Speculative and subject to high credit risk |
| Caa | Of poor standing and subject to very high credit risk |

To ratings within each major category, a modifier of 1 to 3 is appended, with 1 meaning that the obligation ranks in the upper end of its generic rating category and 3 means that the obligation ranks at the lower end of its generic rating category. Ratings of Baa3 or higher are considered investment grade.

[55] Moody's Global Infrastructure Finance, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.

[56] For gas distribution utilities, diversification refers to market position, which reflects the diversity of markets among economic regions and regulatory regimes, the make-up of the customer base (e.g., dependence on industrial load) and growth potential. For electric utilities, the 10% weight attributed to diversification is split between market position (5%) and generation and fuel diversity (5%).

[57] Liquidity encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources.

For the four credit metrics listed above, Moody's indicative ranges for A, Baa and Ba ratings based on those factors are set out in the table below:

**Table 5**

| Metric | A | Baa | Ba |
|---|---|---|---|
| CFO Interest Coverage | 4.5-6.0X | 2.7-4.5X | 1.5-2.7X |
| CFO/Debt | 22-30% | 13-22% | 5-13% |
| CFO less Dividends to Debt | 17-25% | 9-17% | 0-9% |
| Debt/Total Capital | 35-45% | 45-55% | 55-65% |

Each utility is assigned a rating in each of the eight categories based on the criteria applicable to the factor, using the same letter grade scale that is used to assign debt ratings. The actual rating assigned to the utility is based on the weighted average of the ratings assigned to each of the factors. Moody's first applied its new framework to FEI in its May 2010 *Credit Opinion*. The most recent *Credit Opinion* for FEI was issued in July 2011.

In the July 2011 *Credit Opinion*, Moody's assigned the following ratings to each of the eight key factors:

**Table 6**

| Factor | Weighting | Rating |
|---|---|---|
| Regulatory Framework | 25% | AA |
| Ability to Recover Costs and Earn Returns | 25% | A |
| Diversification/Market Position | 10% | A |
| Liquidity | 10% | A |
| CFO Interest Coverage | 7.5% | Ba1 |
| CFO to Debt | 7.5% | Ba2 |
| CFO-Dividends to Debt | 7.5% | Ba2 |
| Debt/Capital | 7.5% | Ba3 |
| Indicated Rating from Methodology Grid | | A3 |
| **Actual Rating** | | **A3** |

Source: Moody's, *Credit Opinion: FortisBC Energy Inc.*, July 21, 2011.

Table 6 shows the FEI's ratings in four of the five Financial Strength categories are non-investment grade, i.e., lower than Baa3. On a weighted average basis, including liquidity, FEI is rated between Baa2 and Baa3 (low investment grade). Excluding liquidity, that is, based on the four quantitative credit metrics only, FEI's financial strength rating is Ba2 (or mid BB on the DBRS/S&P rating scales), i.e., non-investment grade.

Under Moody's "old" rating methodology, which also included a number of financial strength metrics, FEI was Baa-rated on Financial Strength and Flexibility.[58] Despite the increase in allowed ROE and common equity ratio in the *2009 ROE Decision*, FEI's financial strength rating has not been raised. As Moody's noted in the July 2011 *Credit Opinion* for FEI:[59]

> FEI's financial metrics are materially weaker than those of its A3 rated global gas utility peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, UGI Utilities and its sister company, FEVI. We recognize that FEI's weaker financial metrics are largely a function of the deemed equity and allowed ROE approved by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions.

and

> Notwithstanding FEI's low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, a sustained weakening of FEI's Cash Flow Interest Coverage below 2.3x and CFO pre-WC / Debt below 8% combined with a less supportive and predictable regulatory framework would likely result in a downgrade of FEI's rating. This could occur if gas were to lose its competitive advantage over electricity in British Columbia due (*sic*) Provincial policies favouring non-carbon emitting energy sources or other factors.

[58] Moody's, *Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006 and *Credit Opinion: Terasen Gas Inc*., May 27, 2008.
[59] Moody's, *Credit Opinion: FortisBC Energy Inc*., July 21, 2011.

Although the new Moody's rating methodology released in August 2009 gives weight to a different set of credit metrics than the 2006 methodology,[60] there are two metrics common to both, debt/capital and CFO-Dividends to Debt.[61] As the table below shows, Moody's has strengthened its guidelines for the debt ratio across all rating categories and for the CFO-Dividends to Debt ratio in the higher rating categories (A and above).

**Table 7**

| | **Rating Category** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Aa** | | **A** | | **Baa** | | **Ba** | |
| **Metric** | **2006** | **2009** | **2006** | **2009** | **2006** | **2009** | **2006** | **2009** |
| **Debt/ Capitalization** | 30-40% | 25-35% | 40-50% | 35-45% | 50-65% | 45-55% | 65-85% | 55-65% |
| **CFO - Dividends/ Debt** | 21-26% | 25-35% | 15-21% | 17-25% | 10-15% | 9-17% | 5-10% | 0-9% |

Under the 2006 methodology, the 60% debt ratio adopted in the *2009 ROE Decision* placed FEI in the investment grade category (Baa). Under the new methodology, FEI's deemed 60% debt ratio is in the Ba rating category. Moody's most recently reported CFO-Dividends to Debt Ratio (5.9% for 2010) for FEI is within the non-investment grade Ba rating category under both the 2006 and 2009 guidelines.[62]

A comparison of FEI's credit metrics to other relatively pure-play investor-owned Canadian gas and electric utilities with rated debt shows that, although FEI's credit metrics have generally strengthened since the *2009 ROE Decision*, its credit metrics remain well below the median of other relatively pure-play investor-owned Canadian utilities with rated debt.[63]

[60] The new methodology focuses on cash flow rather than earnings based ratios to reduce the impact from non-cash items such as pension expense.
[61] Referred to as Retained Cash Flow to Debt in the 2006 methodology.
[62] Based on reported financial data from FEI's 2011 Consolidated Financial Statements, I calculated the 2011 ratio at 6.6%, or still within the Ba rating category.
[63] Includes all investor-owned Canadian gas and electric utilities currently rated by DBRS.

**Table 8**

| | EBIT Coverage (X) | | | | |
|---|---|---|---|---|---|
| | **2007** | **2008** | **2009** | **2010** | **2011** |
| **FEI** | 2.0 | 1.9 | 2.0 | 2.2 | 2.2 |
| **Canadian Utilities** (Median) | 2.2 | 2.4 | 2.4 | 2.4 | 2.4 |
| | **EBITDA Coverage (X)** | | | | |
| | **2007** | **2008** | **2009** | **2010** | **2011** |
| **FEI** | 2.7 | 2.6 | 2.7 | 3.0 | 3.0 |
| **Canadian Utilities** (Median) | 3.9 | 3.8 | 3.8 | 3.8 | 4.0 |
| | **Cash Flow to Total Debt (%)** | | | | |
| | **2007** | **2008** | **2009** | **2010** | **2011** |
| **FEI** | 8.9 | 10.1 | 10.3 | 10.9 | 11.8 |
| **Canadian Utilities** (Median) | 16.8 | 16.2 | 15.0 | 17.4 | 16.5 |

Notes:

EBIT Coverage: Earnings before Interest and Taxes divided by Interest
EBITDA Coverage: Earnings before Interest, Taxes, Depreciation and Amortization divided by Interest
Cash Flow to Total Debt: Net Income plus Depreciation, Amortization and Deferred Taxes divided by Total Debt

Source: Schedule 7, page 2 of 2.

FEI's credit metrics (as well as those of other Canadian utilities) continue to compare unfavourably to its U.S. peers, with which it competes for capital, as summarized in the table below.

**Table 9**

| | Equity Ratio [1/] | EBIT Coverage [2/] | EBITDA Coverage [2/] | FFO Interest Coverage [3/] | Cash Flow/Debt [2/] |
|---|---|---|---|---|---|
| **FEI** | 40.3% | 2.2X | 3.0X | 2.7X | 11.8% |
| **Medians:** | | | | | |
| **Canadian Utilities** [4/] | 40.5% | 2.4X | 4.0X | 3.4X | 16.5% |
| **U.S. A-Rated Gas LDCs** | 49.2% | 4.4X | 5.3X | 5.7X | 25.9% |
| **U.S. Proxy Utility Sample** | 48.7% | 3.6X | 5.0X | 5.3X | 23.4% |

[1/] 2011
[2/] 2011 and 2010 respectively for Canadian and U.S. companies.
[3/] 2010
[4/] Canadian Utilities are investor-owned utilities with debt currently rated by DBRS.

Source: Schedules 5 (page 1 of 2), 6, 7, 8 and 9.

FEI's allowed return (combination of capital structure and ROE) should provide the opportunity to achieve a degree of financial strength that is comparable to that of its North American peers.

As with Canadian utilities, the actual credit metrics of U.S. utilities reflect the returns (combination of capital structure and ROE) that are awarded by regulators. From January 2010-June 2012, the median common equity ratio adopted by U.S. regulators for gas distribution utilities was 50%, with a corresponding average awarded ROE of 10.05%. For those U.S. gas distribution utilities with weather normalization clauses, decoupling or analogous mechanisms (flat monthly fee rate design), the median allowed common equity ratio was approximately 50% with a corresponding average awarded ROE of 10%.

## F. CHANGES IN ALLOWED CAPITAL STRUCTURE RATIOS FOR CANADIAN UTILITIES

As discussed above, the overall return, which includes both capital structure and ROE, needs to meet the three requirements of the fair return standard. In the 2009 Application, the reasonableness of FEI's proposed 40% equity ratio was evaluated partly by reference to trends in the capital structures of its peers. Changes in the capital structure ratios of FEI's peers since the 2009 Application are also a relevant consideration to the assessment of a reasonable capital structure for FEI in this proceeding.

Since the end of the oral portion of the 2009 Application, there have been a number of increases in the deemed common equity ratios adopted for other ex-BC Canadian utilities with which FEI competes for capital.[64] The deemed common equity ratios of all but one of the Alberta utilities have increased.[65] As noted earlier, in its *Decision 2009-216*, the AUC implemented a base two percentage point across-the-board increase in common equity ratios, with some company-specific adjustments to the base increase. The increases that were approved in that decision were confirmed in *Decision 2011-474.* The base increase in 2009 reflected the following four

[64] Both Enbridge Gas and Union Gas have applied for increases to their deemed common equity ratios, from the 36% that was in place prior to the commencement of their five-year incentive regulation plans (due to expire at the end of 2012) to 40% for Union and 42% for Enbridge, compared to the 40% equity ratio that the OEB has adopted for the Ontario electricity distributors. The two proceedings are on-going.

[65] For ATCO Pipelines in *Decision 2011-474*, due to the AUC's conclusion that, due to its integration with NGTL, its business risk had declined significantly.

considerations: (1) the credit crisis warranted an increase in the equity ratios for all utilities to reflect increased risk and the re-pricing of risk; (2) lower ROEs and tax rates required an increase to maintain credit metrics at the same level as in 2004 (the previous generic cost of capital proceeding); (3) the analysis of equity ratios and credit ratings of relatively pure-play Canadian utilities did not indicate any equity ratio increase was required; and (4) the business risk analysis did not indicate major changes in the relative risks of the various utility segments; any increase in equity ratios should be relatively uniform across the utility sectors and individual utilities unless utility-specific factors require otherwise.

In addition, since the end of the oral portion of the 2009 Application, the allowed common equity ratios for a number of the NEB-regulated pipelines have increased. Foothills, NGTL, and Westcoast have since negotiated common equity ratios of 40%, or four (Foothills and Westcoast) to five (NGTL) percentage points higher than at the time of the 2009 cost of capital proceeding in BC.[66]

In isolation, the trend in the allowed equity ratios of FEI's Canadian peers since the end of the oral portion of the 2009 Application supports, at a minimum, maintaining the 40% common equity ratio adopted for FEI in the *2009 ROE Decision*.

## G. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE

The FBCU are proposing that the equity ratio for FEI, the proposed benchmark BC utility, be established at a minimum of 40%. I agree with this assessment. In my testimony filed with the Commission in the 2009 Application, I concluded that the 40% equity ratio proposed by FEI was within a reasonable range, albeit at the lower end. I continue to hold that opinion, for the following reasons:

[66] National Energy Board, Order TG-03-2010, June 2010, (Foothills Pipe Line Ltd., for 2010-2012); Order TG-05-2010, September 2010, (Nova Gas Transmission Ltd., for 2010-2012); Order TG-01-2011, January 2011, (Westcoast Energy Inc., for 2011-2013).

1. The level of business risk to which FEI is exposed is at least as high as when it was last assessed in 2009.

2. FEI's credit metrics remain weak for its Moody's credit rating, which is at the lower end of the A range, despite the increase in common equity ratio and ROE in 2009. Its quantitative financial strength metrics ratings are all below investment grade guidelines.

3. Moody's debt ratio guidelines have become more stringent since the 2009 Application. Whereas under Moody's old ratings methodology, the 60% debt ratio (40% equity ratio) adopted for FEI in the *2009 ROE Decision* fell into an investment grade rating category (Baa), it now falls into a non-investment grade category (Ba).

4. While FEI's current 40% deemed common equity ratio is comparable to the median (40.5%) actual common equity ratio maintained by other Canadian pure-play investor-owned gas and electric utilities, its credit metrics compare unfavourably to those utilities at the current capital structure and ROE.

5. Since the 2009 Application, common equity ratios for a number of Canadian utilities, with which FEI was compared, have been increased. The increases in the case of the Alberta utilities were not for business risk reasons, but rather for credit metrics and capital market risk reasons. The credit metrics and capital market rationale relied upon by the AUC for its base increase in equity ratios would have similarly applied to FEI.

6. Capital investment requirements for infrastructure in North America and globally have grown to unprecedented levels, which point to significant competition for capital going forward. FEI, as well as other BC utilities, should be positioned so that it can compete successfully, that is, continue to obtain capital as required on

reasonable terms and conditions. At a 40% common equity ratio (and the currently allowed ROE of 9.5%), FEI's equity ratio and credit metrics are much weaker than those of its U.S. utility peers.

The recommended ROE developed in Section VIII is premised on FEI pre-amalgamation, as the benchmark BC utility, maintaining a deemed common equity ratio of 40.0%.

# VIII. FAIR ROE FOR FEI AS BENCHMARK BC UTILITY

## A. IMPORTANCE OF MULTIPLE TESTS

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity:

1. Equity Risk Premium (including, but not limited to, the Capital Asset Pricing Model),
2. Discounted Cash Flow, and
3. Comparable Earnings.

Equity risk premium tests are market-based tests premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. Equity risk premium tests entail estimation of the additional premium or incremental return that an equity investor requires relative to a less risky security, e.g., government bonds or corporate bonds.

Discounted cash flow models are based on the proposition that the market price of a security or value of an investment is equal to the present value of all the future expected cash flows from the security or investment, discounted at a rate that reflects the riskiness of the cash flows. If the price of an equity share is known, and the expected cash flows can be estimated, the investor's expected rate of return can also be estimated.

The comparable earnings test is based on the proposition that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. The comparable earnings test estimates a fair return on equity by reference to returns achievable on the book value of companies subject to a similar level of investment risk to the regulated utility.

Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[67] Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions.[68] These considerations emphasize the importance of reliance on multiple tests.

Each test has its own set of pros and cons. The discounted cash flow test directly measures expected utility returns by using utility-specific data only: prices, dividends and estimates of expected growth in the cash flows to investors. It is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. The comparable earnings test explicitly recognizes that the objective of regulation is to emulate competition and measures returns on the same original cost basis on which utilities are regulated. It is subject to concerns around selection criteria and whether the results are representative of economic returns. The theoretical Capital Asset Pricing Model, an equity risk premium test

---

[67] For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, VA.: Public Utility Reports, Inc., March 1988, page 317).

[68] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.

framed in an elegant, simple construct, has an intuitive appeal. With only three components, it appears, on the surface, easy to apply. Nevertheless, it has its own set of challenges, which are summarized below.

The focus on the challenges of the theoretical CAPM is not to suggest that other tests are necessarily superior, but because a number of Canadian regulators have, in recent years, tended to favour CAPM in their estimation of the allowed ROEs, albeit, in some circumstances, with recognition of its shortcomings and adjustments to the model that may be required. The challenges in the application of the CAPM include:

1. The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require, in contrast to the return that the investor does require or what returns are actually available to investments of comparable risk.

2. The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to the country from which the data are drawn and the time period over which they are measured.

3. The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. The typical application of the CAPM relies heavily on long-term average achieved equity risk premiums in conjunction with a current or forecast risk-free rate.[69] In other words, the typical

[69] Theoretically, an underlying premise of the CAPM is that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity

application of the model captures changes in interest rates, by using a current or forecast interest rate as the risk-free rate, but the model itself does not provide any insight into how the equity market risk premium changes when interest rates change.

The need to capture and measure changes in the size of the market risk premium due to changes in the required equity market return and the relative risk of the so-called risk-free security introduces a further complication in the application of the CAPM. This obstacle is particularly problematic with current and forecast long-term Canada bond yields at historically low levels.

4. The achieved equity market risk premium in Canada has been significantly influenced by historic long-term Government of Canada bond yields and returns. The improvement in Canada's fiscal performance over the past fifteen years contributed to a steady decline in long-term Government of Canada bond yields. This secular decline, combined with recent global factors that have led to further downward movement, has resulted in a wide gap between the historical average yields which underpin the calculation of achieved market risk premiums and the prevailing and forecast yields. Since the long-term historic average long-term Government of Canada bond yield exceeds the forecast yield by a wide margin, the long-term average achieved market risk premium is unlikely to be an accurate estimate of the required market risk premium.

5. The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks

---

market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the equity market return is <u>highly</u> correlated with the risk-free rate, that is, the equity market return and the risk-free rate move in tandem. Consequently the application of the test frequently proceeds on an assumption directly in conflict with an underlying premise of the model itself.

> and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return.[70]

The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a fair return, particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility industry.

The Commission, in the *2009 ROE Decision*, recognized the challenges of the CAPM, the need for adjustments, and the need to consider the results of multiple tests. The Commission noted (page 45):

> that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.
>
> The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.

In its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084*, December 11, 2009, pages 45-46 ("*Report of the Board on the Cost of Capital*"), the OEB stated:

> The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate".

[70] The beta is a statistical measure of the sensitivity of the return of a particular security or portfolio of securities to the return on the overall market portfolio. The return of a security with a beta of 0.50 will change by approximately 50% of the change in the return on the overall market portfolio, which by definition, has a beta of 1.0.

> This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP [equity risk premium] directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates…
>
> The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce “the number” that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.

## B. DISTINCTION BETWEEN MARKET AND BOOK VALUES FOR FAIR ROE DETERMINATION

Discounted cash flow (DCF) and equity risk premium models represent conceptually different ways that investors might approach estimating the return they require on the market value of an equity investment. While the DCF and equity risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. The determination of a fair return on book equity needs to recognize that distinction.

In simple terms, assume that the cost of equity for a company whose stock value is $200 is 10%. That means that investors require a return, in dollar terms, of $20. If the book value of the stock is $100, and the 10% cost of equity is applied to the $100 book value rather than the $200 market value, the resulting return in dollar terms is only $10, or half that which investors require.

The proxy companies used for the purpose of estimating the cost of equity for the benchmark BC utility have market-to-book ratios of approximately 1.7X (U.S. sample) to 2.6X (Canadian sample),[71] well above the market-to-book ratio of 1.0 that conceptually would equate the return on book value (in dollar terms) to the return estimated by reference to the market-based DCF or equity risk premium tests.

When the allowed return is applied to an original cost book value, a market-derived cost of attracting capital should be converted to a fair and reasonable return on book equity so that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value. Failure to make such a conversion will produce an inadequate level of earnings which will discourage utilities from making investments in critical infrastructure.

It has been suggested that the observed market-to-book ratios of utilities are evidence that the allowed returns on equity are too high (or at least fair).[72] Such a conclusion is unwarranted.

Book values are accounting-based and reflect the historic impacts of various financial statement accounting conventions (and changes in those conventions over time) for recording such items as depreciation reserves, deferred taxes, pension assets and liabilities, unrealized gains and losses, etc. The sole impact of accounting conventions over time on the recorded amount of equity can cause the book value of equity to diverge significantly from the economic value, particularly in the presence of inflation, and as well as the going concern value of the corporation.

Market values reflect returns that investors expect to earn over the longer-term, not the returns that regulators have historically or recently allowed. Expected returns may be materially higher than allowed returns due to factors such as the anticipation of achievement of synergies among existing operations, of higher returns achieved from non-regulated operations, through performance-based regulation and/or growth in the customer or asset base, the perceived ability

[71] Based on daily average share price from March 16, 2012 to June 15, 2012 compared to fiscal year-end 2011 book value per share. Excluding Accumulated Other Comprehensive Income from equity, which reflects cumulative unrealized gains and losses, e.g., in the market value of pension assets, the median market/book ratio of the Canadian utilities is lower, at 2.3X.

[72] For example, AUC, *Decision 2009-216*, pages 77-78.

to improve shareholder returns by leveraging assets, and the ability of the firms to take advantage of growth opportunities beyond the existing asset base.

Further, investors are likely to value utility shares on a relative basis (to other equity securities) rather than on an absolute basis (relative to the utilities' own book values). Over time, the market-to-book ratios of publicly traded utilities companies have generally tracked the overall tenor or "mood" (and the market-to-book ratio) of the equity market as a whole.

Moreover, while some might contend that the market-to-book ratio of utilities should be 1.0 or close thereto, economic principles suggest otherwise. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets. Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.[73]

## C. SELECTION OF COMPARABLE UTILITIES

The estimation of the cost of equity for the benchmark BC utility, FEI, is based in large part on estimates of the cost of equity of comparable risk utilities. Comparable risk companies are used as a proxy for the benchmark BC utility to recognize that investors have alternatives for their investment capital. Rational investors will commit funds to the investments that promise the highest return for a given level of investment (business plus financial) risk. Unless the return

[73] See Appendix F for further discussion.

that can be expected on an investment in the benchmark BC utility is equal to that available from comparable risk investments, investors will direct their funds elsewhere.

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. The cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment if the magnitude of the total risks (business plus financial) of the sample and the specific utility is comparable. In principle, given a sufficiently large universe of utilities, different samples of proxy companies can be selected, each designed to be a proxy for a specific utility. If, however, the total risk of the sample and the specific utility is not equal, the solutions include: (1) changing the specific utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the specific utility; or (3) some combination of (1) and (2). To minimize the extent to which such adjustments are required, the point of departure should be the selection of companies that are of relatively similar total risk to the benchmark BC utility, FEI.

In Canada, there are only six publicly-traded Canadian companies whose operations are largely regulated.[74] These companies are relatively heterogeneous in terms of both operations[75] and size.[76] The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the cost of equity for an average risk Canadian utility. The operating (or business) environments are similar, the regulatory model in the U.S. is similar to

[74] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., TransCanada Corporation and Valener Inc.
[75] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.
[76] Ranging from an equity market capitalization of approximately $550 million (Valener) to $31.9 billion (Enbridge).

the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar.[77]

Equity markets are global; investors are increasingly committing equity funds beyond domestic borders. Canadian investors looking to commit funds to utility equity shares will compare returns available from Canadian utilities to returns available from utility shares globally, including returns from U.S. utilities (both market and allowed). A review of the major Canadian public sector defined benefit pension funds which list all their equity holdings individually shows that the funds have invested in a significant number of U.S. utilities.

While market data for the Canadian utilities provide some perspective on the fair return for FEI as the benchmark BC utility, a more accurate assessment can be made by reliance on a sample of U.S. utilities drawn from a much broader universe. Nevertheless, not all utilities in the U.S. would be considered of similar risk to the benchmark BC utility, FEI, just as not all utilities in the U.S. would be similar to each other. Consequently, the sample of U.S. utilities which serve as a proxy for the benchmark BC utility was selected according to criteria designed to (1) identify companies that are of relatively similar total risk to the benchmark BC utility (FEI) and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

[77] The OEB's *Report of the Board on the Cost of Capital*, pages 21-22, stated, "Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." [fn] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed."

The NEB's *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc.*, *RH-1-2008*, page 71, concluded that "In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008."

The Commission's *2009 ROE Decision*, page 16, found that, "In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics."

To ensure comparability with the benchmark BC utility, only relatively pure-play U.S. utilities were selected. The selected utilities are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. utility sample is A-, identical to the A- rating accorded on average to the universe of Canadian utilities rated by S&P. All of the companies in the sample are assigned an "Excellent" business risk ranking, the same as the ranking assigned to the majority of Canadian utilities rated by S&P.[78] The median Moody's rating for the U.S. utility sample is Baa1 (Schedule 15, page 1 of 2), equal to the median of the ratings that Moody's has assigned to Canadian gas and electric utilities.[79] The average and median *Value Line* Safety ranks of the U.S. utility sample are 1.5 (Schedule 15, page 1 of 2); the Safety ranks of the two Canadian regulated companies covered by *Value Line* (Enbridge Inc. and TransCanada Corp.) are 1 and 2 respectively.[80] The average difference in the adjusted monthly betas of publicly-traded Canadian utilities and U.S. utility sample for five-year periods ending 1993-2011 has been minor (Schedule 14). Even if equity investors viewed the U.S. utility sample as facing higher business (combined operating and regulatory) risk than the benchmark BC utility (FEI), the U.S. utility sample has higher common equity ratios (lower financial risk). The average common equity ratio of the sample of U.S. utilities is approximately 49% (Schedule 6), compared to FEI's 40% deemed common equity ratio and the median 40% actual common equity ratio of investor-owned Canadian utilities with rated debt (Schedule 5).[81]

[78] Standard & Poor's assigns a business risk ranking to each of the companies it rates. There are six business risk categories, ranging from "Excellent" to "Vulnerable".
[79] Including FEI (A3), FEVI (A3), FortisAlberta (Baa1), FortisBC Inc. (Baa1), Hydro One (Baa1 on a stand-alone basis), Newfoundland Power (Baa1), and Nova Scotia Power (Baa1).
[80] The Safety rank represents *Value Line's* assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.
[81] Appendix B provides both details of the selection criteria and information on the selected U.S. utilities' operations and regulation, including for each a list of the regulatory mechanisms that have been adopted. Schedule 15, page 1 of 2 provides additional quantitative and qualitative data for the selected U.S. utilities. The most recently allowed ROEs and capital structures for the operating companies are found on Schedule 15, page 2 of 2.

## D. EQUITY RISK PREMIUM TESTS

### 1. Conceptual Underpinnings

Equity risk premium tests are premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure. An equity risk premium can be estimated relative to a risk-free rate, for which a government bond yield is typically the proxy, as well as relative to utility bond yields, depending on the type of equity risk premium test being conducted.

Three equity risk premium tests were used to estimate the utility cost of equity:

1. Risk-Adjusted Equity Market Risk Premium Test
2. DCF-Based Equity Risk Premium Test
3. Historic Utility Equity Risk Premium Test

**2. Risk-Free Rate**

The application of equity risk premium tests in relation to a risk-free rate requires a forecast of the risk-free rate to which the equity risk premium is applied. A forecast long-term (30-year) Government of Canada bond yield is most widely used as the risk-free rate, although long-term Government of Canada bond yields are not risk-free. They are considered to be free of default risk, but are subject to interest rate risk.[82] Use of the long-term government bond yield recognizes (1) the administered nature (determined by monetary policy) of short-term rates; and (2) the long-term nature of the assets to which the utility equity return is applicable.

For 2012, the long-term (30-year) Government of Canada bond yield, based on the actual yields through the end of May 2012 and forecasts[83] for the remainder of the year is 2.6%. For the three-year period 2013-2015, based on the available forecasts, the 30-year Canada bond is expected to yield approximately 4.0%.[84]

Although the 30-year Government of Canada bond yield is expected to rise from its current historically and abnormally low levels over the next three years, it is still anticipated to average well below levels expected to prevail over the longer-term. Over the longer-term (2016-2022), Consensus Economics' survey of economists anticipates that the 10-year Canada bond yield will average close to 4.7%.[85] The corresponding 30-year Canada bond yield, assuming the historical long-term average spread between 30-year and 10-year Canada bonds of 35 basis points prevails, would be approximately 5.0%. The relatively low expected level of the risk-free rate needs to be

[82] If interest rates rise, the value of the bond will decline.
[83] Forecasts provided by BMO Capital Markets, CIBC World Markets, Desjardins Economic Studies, National Bank Economy and Strategy Group, RBC Economics, ScotiaBank Group and TD Securities. All of these institutions contribute to Consensus Economics, *Consensus Forecasts*, which only publishes a consensus forecast for 10-year Government of Canada bond yields.
[84] Comprised of a forecast yield of 3.2% for 2013, based on the forecasts of BMO Capital Markets, CIBC World Markets, Desjardins Economic Studies, RBC Economics, ScotiaBank Group and TD Securities, and forecast yields of 3.2%, and of 4.0% and 4.6% for 2014 and 2015 respectively, based on Consensus Economics, *Consensus Forecasts*, April 2012. Consensus Economics publishes a long-term forecast twice annually, in April and October. Consensus Economics' April 2012 forecasts for the 10-year Government of Canada bond yield were 3.6% and 4.2% for 2014 and 2015 respectively. A spread of 35 basis points (long-term average) to 60 basis points (June 2012) was added to the 10-year Government of Canada bond yield forecasts to arrive at the 30-year Government of Canada bond yield forecasts for 2014 and 2015.
[85] Consensus Economics, *Consensus Forecasts*, April 2012.

expressly recognized in the estimation of the magnitude of market and utility equity risk premiums.[86, 87]

**3. Risk-Adjusted Equity Market Risk Premium Test**

3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required equity market risk premium for a utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required utility equity market risk premium. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require (in contrast to what the investor does require). Its focus is on the minimum return that will allow a company to attract equity capital.

[86] In AUC, *Decision 2011-474*, the Commission concluded "it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates." (paragraph 56) Further, it considered that "it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value" (paragraph 57) concluding " that the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates." (paragraph 58)

[87] In its March 2012 *Equity Gilt Study*, Barclays Capital stated:

> Our analysis suggests that current equity prices are consistent with future returns that are not far from historic norms. By contrast, rates of returns on risk-free assets stand out as abnormally low, as they are currently negative on an inflation adjusted basis in nearly all cases. An important reason for these low yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years. The implication is that equity risk premia - the difference between the expected yields on equities and risk free assets - are likely to remain historically high even if cyclical factors could lead them to reverse somewhat over the next few years. (page 4)

Barclays' concluded that equity risk premia "are meaningfully higher than historical experience." (page 6)

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on the S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

### 3.b. Equity Market Risk Premium

#### 3.b.(i) Overview

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, the analysis of historic returns and risk premiums focused on both the post-World War II period (1947-2011)[88] and on longer periods. My analysis of historic returns and risk premiums was based on the Canadian experience as well as on the U.S. experience as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The U.S. experience is relevant given the close relationship between the two economies, the fact that the U.S. has historically been the single largest alternative destination for Canadian portfolio investment (See Appendix A, page A-15) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

[88] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy; and
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

3.b.(ii) Historic Returns and Risk Premiums

Table 10 below summarizes the achieved equity and government bond returns and the corresponding experienced risk premiums for Canada and the U.S.[89]

**Table 10**

| Period | Stock Return | Bond Total Returns | Bond Income Returns | Risk Premium Over Bond Total Returns | Risk Premium Over Bond Income Returns |
|---|---|---|---|---|---|
| **Canada** | | | | | |
| **1924-2011** | 11.4% | 6.6% | 6.0% | 4.8% | 5.4% |
| **1947-2011** | 11.8% | 7.1% | 6.7% | 4.7% | 5.0% |
| **U.S.** | | | | | |
| **1926-2011** | 11.8% | 6.1% | 5.2% | 5.6% | 6.6% |
| **1947-2011** | 12.3% | 6.6% | 5.9% | 5.7% | 6.4% |

Source: Schedule 10.

The raw data in Table 10 show that, on average, equity returns in Canada have averaged approximately 11.5% to 11.75%, compared to average bond income[90] returns of approximately 6.0% to 7.0%, resulting in average achieved risk premiums relative to bond income returns in the range of approximately 5.0% to 5.5%.[91] The slightly lower achieved equity risk premium relative to bond income returns achieved during the post-World War II period reflects a slightly higher average equity return relative to the longer period, which was more than offset by higher bond income returns.

The corresponding raw data for the U.S. indicate average equity market returns of approximately 11.75% to 12.25%, corresponding to average bond income returns of approximately 5.25% to 6.0%, resulting in an average achieved equity risk premium of approximately 6.5% relative to bond income returns.

[89] The equity and bond market returns in Table 10 represent arithmetic averages of historical returns. Appendix A explains the rationale for using arithmetic, rather than compound (geometric) averages for the purpose of estimating the expected return from historic returns.

[90] The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield. The bond total return includes annual capital gains or losses and reinvestment of the bond coupons. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.

[91] The median risk premiums over the periods 1924-2011 and 1947-2011 were somewhat higher, 6.2% and 5.5%, respectively, relative to bond income returns.

3.b.(iii) Canadian Equity and Government Bond Returns

To assess whether there has been a trend in the underlying returns which generate the achieved risk premiums, the returns and risk premiums for each decade over the period 1932 to 2011 were examined and are presented in Table 11 below.

**Table 11**

| 10-YEAR AVERAGE CANADIAN MARKET RETURNS | | | | | |
|---|---|---|---|---|---|
| | **Canadian Stock Returns** | **Canadian Bond Total Returns** | **Canadian Risk Premium Over Bond Total Returns** | **Canadian Bond Income Returns** | **Canadian Risk Premium Over Bond Income Returns** |
| 1932-1941 | 9.1% | 6.6% | 2.5% | 3.6% | 5.5% |
| 1942-1951 | 18.9% | 2.4% | 16.6% | 2.9% | 16.0% |
| 1952-1961 | 13.2% | 2.4% | 10.7% | 4.1% | 9.1% |
| 1962-1971 | 7.8% | 4.5% | 3.2% | 6.1% | 1.7% |
| 1972-1981 | 13.6% | 2.7% | 11.0% | 9.7% | 3.9% |
| 1982-1991 | 10.8% | 16.5% | -5.7% | 11.1% | -0.2% |
| 1992-2001 | 11.4% | 10.8% | 0.6% | 7.1% | 4.3% |
| 2002-2011 | 9.1% | 8.8% | 0.3% | 4.4% | 4.7% |

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*.

Table 11 indicates a clear pattern in bond returns, reflecting:

1. rising bond yields in the 1950s through the early 1980s, which produced capital losses on bonds and low bond total returns;

2. high total bond returns and yields in the 1980s, reflecting the high rates of inflation; and,

3. high bond total returns in the 1990s and the 2000s, relative to income returns, reflecting the secular decline in long-term government bond yields, which

resulted in capital gains and total bond returns, well in excess of the concurrent bond yields.[92]

In contrast to the pattern in bond returns, Table 11 does not indicate a discernible pattern in equity market returns.[93]

However, further analysis of the historical data indicates, as shown in Table 12 below, that, historically, lower bond income returns have been associated with higher achieved risk premiums.

**Table 12**

| | **Averages for the Period: 1924-2011** | | | **Averages for the Period: 1947-2011** | | |
|---|---|---|---|---|---|---|
| **Bond Income Returns:** | **Equity Returns** | **Bond Income Returns** | **Risk Premium** | **Equity Returns** | **Bond Income Returns** | **Risk Premium** |
| **Below 4%** | 13.9% | 3.2% | 10.7% | 17.9% | 3.3% | 14.7% |
| **Below 5%** | 12.6% | 3.7% | 8.9% | 13.8% | 3.6% | 10.2% |
| **Below 6%** | 11.1% | 4.2% | 7.0% | 11.6% | 4.4% | 7.2% |
| **Below 7%** | 11.3% | 4.3% | 7.0% | 11.9% | 4.6% | 7.3% |
| **Below 8%** | 11.8% | 4.6% | 7.3% | 12.6% | 4.9% | 7.6% |
| **Below 9%** | 10.9% | 4.9% | 5.9% | 11.0% | 5.4% | 5.6% |
| **All Observations** | 11.4% | 6.0% | 5.4% | 11.8% | 6.7% | 5.0% |

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*.

Table 12 above indicates that, except at the lowest levels of long-term Government of Canada bond income returns, average equity returns have been broadly in the range of approximately 11.0% to 12.5% during the two periods. At bond income returns below 8% (average of 4.5% to 5.0%), the corresponding equity risk premium averaged approximately 7.25% to 7.5%. Only when the highest levels of bond income returns are included do the average achieved equity risk premiums drop to approximately 5.5% to 6.0% and then to approximately 5.0% to 5.5%. In

[92] The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.
[93] Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2011 and 1947-2011 are estimated at 0.00 for both periods.

other words, the historical data indicate that the equity risk premium has varied with bond yields, i.e., higher risk premiums at lower levels of bond yields and vice versa.

The forecast 4.0% 30-year Government of Canada bond yield for 2013-2015 is 2.0 percentage points lower than the long-term average bond income return (6.0%) and 2.7 percentage points lower than the post-World War II average bond income return (6.7%). The 2013-2015 forecast long-term Government of Canada bond yield of 4.0% suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, of approximately 7.25% to 7.5%.

3.b.(iv) Impact of Inflation on Equity Market Returns[94]

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking equity nominal (inclusive of inflation expectations) market return should differ from the historic nominal returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in Canada was higher than the rate of inflation currently forecast to prevail over the longer term. The arithmetic average CPI rate of inflation from 1926-2011 in Canada was 3.0%; the most recent consensus long-term (2013-2022) forecast of CPI inflation is 2.0%.[95] The lower forecast rate of inflation compared to the historical rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically. However, an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table 13 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

[94] The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital. I analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward. The analysis is summarized in Appendix A.
[95] Consensus Economics, *Consensus Forecasts*, April 2012.

**Table 13**

| Inflation Range | Nominal Equity Return | Average Rate of Inflation | Real Equity Return |
|---|---|---|---|
| Less than 1% | 15.7% | -1.4% | 17.0% |
| 1-3% | 12.4% | 1.9% | 10.4% |
| 3-5% | 4.8% | 4.1% | 0.7% |
| Over 5% | 12.5% | 9.2% | 3.3% |
| Avg. 1924-2011 | 11.4% | 3.0% | 8.4% |

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011;* www.statscan.ca.

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation for the purpose of estimating the future equity risk premium. The average nominal equity returns in Canada were approximately 11.4% over the longer-term and 11.8% since the end of World War II, or approximately 11.5% to 11.75%.

It also bears noting that, while the average real equity return in Canada over the longer period was 8.4%, the average is materially affected by the inclusion of high inflation years. When years in which inflation exceeded 10% are excluded (seven of 88 observations), the average real equity return is a full percentage point higher, i.e., 9.4%. The corresponding average rate of CPI inflation was 2.3%, similar to the forecast rate of inflation. The average real equity return is similar, at approximately 9.5%, when the years in which inflation exceeded 10% and the same number of abnormally low inflation years (average of -4.1%) are removed. At a real equity return of 9.5% and an inflation rate of 2.0%, the indicated nominal equity return is approximately 11.5%. At a nominal equity return of 11.5%, the market equity risk premium at the forecast long-term Canada bond yield of 4.0% is 7.5%.

3.b.(v) Comparison of Canadian and U.S. Returns and Risk Premiums

A comparison of the returns in Canada and the U.S. over the longer-term and the post-World War II period shows that the equity market returns in the two countries have been similar. On average the achieved equity market returns in the two countries have been in the approximate range of 11.5% to 12.25% (see Table 10 above).

Despite relatively similar equity market returns, the achieved risk premium (equity market returns less bond income returns) in Canada has been approximately 1.2% to 1.4% lower than in the U.S. The difference in the equity market returns accounts for 0.4% to 0.5% of the difference in the observed risk premiums. Approximately two-thirds of the difference is attributable to higher bond yields historically in Canada. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points.

With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) declined and the differential between Canadian and U.S. government bond yields that existed historically fell. Between 1998 and 2011, the average yield on 10-year Government of Canada bonds was only slightly higher (+6 basis points) than the corresponding average yield on 10-year U.S. Treasury bonds. The corresponding differential between the yields on the long-term (30-year) government bonds was -16 basis points.

With respect to the relative risk of the two equity markets, the historic annual volatility in the two markets over the longer-term has been quite similar. The table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2011 and post-World War II (1947-2011) for the two countries.

**Table 14**

| | **Canada** | | | **United States** | | |
|---|---|---|---|---|---|---|
| | **Arithmetic Average** | **Standard Deviation** | **Compound Average** | **Arithmetic Average** | **Standard Deviation** | **Compound Average** |
| 1926-2011 | 11.2% | 18.9% | 9.6% | 11.8% | 20.3% | 9.8% |
| 1947-2011 | 11.8% | 17.1% | 10.4% | 12.3% | 17.4% | 10.9% |

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

To put the differences in the relative risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns.

For the longer period, 1926-2011, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the difference in both Canada and the U.S. was approximately 1.4%. The two differentials between the Canadian and U.S. arithmetic and compound average returns can be interpreted as the difference in equity return required for the difference in volatility between the two markets. In other words, based on the longer period, the equity market return required would be 0.30% higher in the U.S. than in Canada and based on the post-World War II period, the equity market return required would be the same in the U.S. and in Canada. In sum, the differences are *de minimus*.[96]

With similar government bond yields in the two countries for more than a decade, U.S. historical equity market risk premiums are a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors. As shown in Table 10 above, the average achieved equity risk premium relative to bond income returns in the U.S. has been approximately 6.5%. Similar to Canada, however, as demonstrated in Table 15 below, higher risk premiums have been associated with lower bond income returns.

[96] Since the onset of the financial crisis (August 2007) to the end of May 2012, the two markets have exhibited similar volatility; the standard deviations of weekly price changes in the S&P/TSX Composite (Canada) and the S&P 500 (United States) have been virtually identical.

**Table 15**

| Bond Income Returns: | Averages for the Period: 1926-2011 Equity Returns | Bond Income Returns | Risk Premium | Averages for the Period: 1947-2011 Equity Returns | Bond Income Returns | Risk Premium |
|---|---|---|---|---|---|---|
| **Below 4%** | 13.9% | 2.9% | 11.0% | 19.0% | 2.9% | 16.1% |
| **Below 5%** | 11.9% | 3.3% | 8.6% | 13.2% | 3.6% | 9.6% |
| **Below 6%** | 11.1% | 3.6% | 7.5% | 11.7% | 4.0% | 7.6% |
| **Below 7%** | 10.7% | 3.9% | 6.8% | 11.0% | 4.4% | 6.6% |
| **Below 8%** | 10.7% | 4.4% | 6.3% | 10.9% | 5.0% | 6.0% |
| **Below 9%** | 11.3% | 4.7% | 6.6% | 11.7% | 5.3% | 6.4% |
| **All Observations** | 11.8% | 5.2% | 6.6% | 12.3% | 5.9% | 6.4% |

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

As Table 15 shows, the 6.6% average historical equity risk premium corresponds to an average bond income return of 5.2%, approximately 1.2 percentage points higher than the 2013-2015 forecast 4.0% 30-year Canada bond yield. The experienced equity risk premium at levels of bond income returns similar to the 2013-2015 forecast 30-year Canada bond yield was in the range of approximately 6.75% to 7.5%.

3.b.(vi) Equity Market Risk Premium

Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, and the observed negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the nominal equity market return is approximately 11.5%, based on Canadian equity market returns and supported by U.S. equity market returns. At the forecast 4.0% 30-year Government of Canada bond yield, the corresponding equity market risk premium is 7.5%. The analysis of Canadian equity risk premiums in conjunction with bond income returns supports a market equity risk premium of 7.25% to 7.5% at the forecast 4.0% 30-year Government of Canada bond yield. Based on U.S. data, a similar analysis supports an equity risk premium of 6.75% to 7.5%. With preponderant weight given to the Canadian data, the indicated equity market risk premium at the forecast 4.0% 30-year Government of Canada bond yield is in the range of 7.25% to 7.50%.

## 3.c. Relative Risk Adjustment

### 3.c.(i) Overview

The market risk premium result needs to be adjusted to recognize the relative risk of the benchmark BC utility, FEI. The theoretical CAPM holds that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments. In the simple, one risk variable CAPM, the non-diversifiable risk is captured in beta.

Impediments to reliance on the equity beta as the sole relative risk measure include:

1. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable. The determination of the return on equity that investors require for bearing the risk of a particular investment is more complex than the single risk variable, beta, implies.

2. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors. This premise erroneously implies that investors are only concerned with the price volatility of their equity investments, not the underlying fundamental risks that may lead to loss of earning power and ultimately a failure to recover their invested capital.

3. The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement. Empirical tests of the CAPM and experienced returns undermine the validity of that assumption.

4. Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that move counter to the rest of the equity market could be expected to have betas that are negative. In that case, the CAPM would posit that the cost of equity capital for would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile. The proposition that a firm's cost of equity could be lower, not only than its own cost of debt, but than the risk-free rate is dubious at best.

5. Utilities are not investing in a portfolio of securities. They are committing capital to long-term assets. Once the capital is committed, it cannot be withdrawn and redeployed elsewhere. The CAPM does not capture that reality.

Thus, a risk measurement that reflects those considerations is relevant for estimating the equity risk premium applicable to an average risk Canadian utility.

3.c.(ii) Total Market Risk

These considerations support focusing on total market risk, as well as on beta, to estimate the relative risk adjustment for a utility. The absence of an observable relationship between "raw"[97] betas and the achieved market returns on equity in the Canadian market[98] provides further support for reliance on total market risk to estimate the relative risk adjustment.

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total risk of the benchmark BC utility, the S&P/TSX Utilities Index was used as a proxy. The standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, including the Utilities Index, were calculated over five-year periods ending 1997 through 2011 (Schedule 11).

[97] The term "raw" means that the beta is solely a statistical calculation of the historical relationship between the price movements of a stock and the corresponding price movements of the market portfolio.
[98] See Appendix A, pages A-21 to A-22.

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 11 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for an average risk Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(iii) Historical "Raw" Betas of Canadian Utilities

Schedule 14, pages 1 to 3 summarizes "raw" betas calculated using monthly and weekly price changes[99] for the five major publicly-traded Canadian utilities, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector.[100]

As Schedule 14, page 1 indicates, there was a significant decline in the calculated "raw" monthly five-year betas of the individual Canadian regulated utilities between 1994-1998 and 1999-2005 (from approximately 0.50 to 0.0 and slightly negative). Following an increase in 2007 to slightly above 0.50, the "raw" monthly betas for the individual Canadian regulated utilities again declined in 2008 to approximately 0.20 and have remained at a similar level through the end of 2011.

The observed levels and pattern of the calculated "raw" utility betas in 1999-2011 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the greater sensitivity of utility stock prices than the equity market composite to rising

[99] The use of price betas for utilities has been criticized on the grounds that the exclusion of dividends from the calculated betas overestimates the betas. A comparison of price and total return (including dividends) betas for Canadian utilities showed that there was no material difference between the two.

[100] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006); and (4) the more extreme price changes of the market as a whole during the financial crisis and the subsequent market recovery.[101]

There can be significant differences in measured "raw" betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices.[102] Table 16 below shows that, for the five large Canadian utilities whose shares are regularly traded, the mean and median five-year "raw" betas ending December 2008 to December 2011 calculated using weekly price changes were twice as high as the corresponding mean and median betas calculated using monthly price changes.[103] These large differences due solely to the choice of interval cast significant doubt on how meaningful calculated betas are as a measure of relative risk.

---

[101] Schedule 12 shows that utilities were not the only companies whose betas were negatively impacted by the technology sector bubble and subsequent market decline. To illustrate, the five-year monthly beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87. Schedule 12 also demonstrates how variable betas are generally. For example, between 2002 and 2011, the five-year monthly betas for the energy sector ranged from 0.17 to 1.44.

[102] There is no theoretically correct time interval for calculations of betas. Betas are frequently, but not exclusively, measured over five years using monthly price change intervals (60 observations). For example, Bloomberg calculates betas over three-year periods using weekly price change intervals (156 observations) whereas *Value Line*, which also utilizes weekly prices, estimates the beta over a period of 2.5 to 5 years (over 250 observations). The measurement of betas over a five-year period is simply a convention. In *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, 2nd Ed., Englewood Cliffs, New Jersey: Prentice-Hall, 1987, page 114, the author, Dr. Diana Harrington, noted that the CAPM itself provides no guidance with respect to the choice of a measurement horizon; the five-year estimation period (i.e., 60 monthly observations) became widely used because of the availability of monthly data in computer-readable form, and the need for a reasonably sized sample.

[103] A similar pattern can be observed for the proxy sample of U.S. utilities.

| | **Weekly Data** | | **Monthly Data** | |
|---|---|---|---|---|
| | **Mean** | **Median** | **Mean** | **Median** |
| 2008 | 0.60 | 0.61 | 0.37 | 0.37 |
| 2009 | 0.60 | 0.61 | 0.40 | 0.38 |
| 2010 | 0.61 | 0.61 | 0.43 | 0.40 |
| 2011 | 0.59 | 0.62 | 0.42 | 0.37 |

**Table 16**

| | Weekly Data | | Monthly Data | |
|---|---|---|---|---|
| | **Mean** | **Median** | **Mean** | **Median** |
| 2008 | 0.46 | 0.45 | 0.25 | 0.21 |
| 2009 | 0.43 | 0.44 | 0.22 | 0.2 |
| 2010 | 0.44 | 0.44 | 0.23 | 0.21 |
| 2011 | 0.45 | 0.44 | 0.21 | 0.21 |

3.c.(iv) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded Canadian utility company shares and of the S&P/TSX Utilities Index explain a relatively small percentage of the actual achieved market returns over time. The following analysis 1) estimates how much of the historical utility market returns can be explained by the equity market, long-term Government of Canada bonds and other factors and 2) uses these relationships to assist in the determination of an appropriate estimate of the required relative risk adjustment.

In the context of the CAPM, the utility return should equal:

Risk-Free Rate + Beta X (Equity Market Return – Risk-Free Rate)

A regression of the monthly returns on the TSX Utilities Index against the market risk premium measured as the return on the TSX Composite less the risk-free rate as proxied by 90-day Treasury bill returns over the period 1970-2011[104] shows the following:

**Table 17**

| | | | | |
|---|---|---|---|---|
| Monthly TSX Utilities Index Return | = | 0.009 | + 0.465 | { Monthly TSX Composite Excess Return } |
| t-statistics | = | 5.4 | 13.8 | |
| $R^2$ | = | 28% | | |

[104] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for the period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2011.

The relationship quantified in the above equation suggests a long-term utility beta of 0.465. However, the $R^2$, which measures how much of the variability in utility returns is explained by variability in the returns of the equity market as a whole, is only 28%. That means 72% of the monthly volatility in utility returns remains unexplained.[105] The intercept in the equation should, in principle, represent the risk-free rate. Over the entire 1970-2011 period, the average annual return on Treasury bills was 7.0%; the corresponding intercept in the equation above is 10.85%, when expressed on an annualized basis.[106] The difference between the calculated intercept and the average 90-day Treasury bill return of approximately 3.9% represents the component of the utility return incremental to what the CAPM would predict.

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly excess long-term Canada bond returns to the analysis indicates the following:

**Table 18**

| | | | | | | |
|---|---|---|---|---|---|---|
| Monthly TSX Utilities Index Return | = | 0.0075 | + .40 | { Monthly TSE Composite Excess Return over T-bills } | + .46 | { Monthly Excess Long Canada Bond Return over T-bills } |
| t-statistics | = | 5.0 | 12.4 | | 8.6 | |
| $R^2$ | = | 37% | | | | |

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (37% versus 28%). The second regression equation suggests that utility returns have had approximately 40% of the volatility of equity market returns and approximately 46% of the volatility of government bond market returns, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility return volatility unexplained.

[105] As shown in Schedule 14, page 2 of 6, the $R^2$s of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2011 have been extremely low, averaging less than 10%. The low $R^2$s indicate that very little of the volatility in the utility share prices is explained by the volatility in the equity market composite. It bears noting that, while the five-year "raw" monthly and weekly betas ending December 2011 of Canadian Utilities Limited, at 0.03 and 0.38 respectively, are the lowest of the individual Canadian utilities, its absolute price volatility, measured by the standard deviation of monthly price changes, was the highest of the group.

[106] The regression was performed using monthly data, so the intercept of 0.009 is equal to the monthly return on 90-day Treasury bills. The annualized return is equal to $(1+.009)^{12}-1.0 = 0.1085 = 10.85\%$.

In this equation, the market equity risk premium is equal to the return on the equity market composite less the Treasury bill return and the long-term Canada bond risk premium, or maturity premium, is equal to the return on the long-term Canada bond less the Treasury bill return. The intercept in the equation in Table 18, as was the case in Table 17, is the sum of the risk-free rate, as proxied by the 90-day Treasury bill return, and the component of the return which differs from what the CAPM would have predicted. As in Table 17, the equation intercept is a monthly number. When annualized, the intercept equals approximately 9.4%.[107] Since the average annualized Treasury bill return over the 1970-2011 period of analysis was 7.0%, the indicated utility return was 2.5% higher than predicted by the two variable model.

To assess whether this unexplained component of the utility returns arises from a downward trend in utility risk over the period 1970-2011, I analyzed the trend in the relative total volatility of the S&P/TSX Utilities Index, measured by the ratio of five-year monthly standard deviations of the total market returns of the Utilities Index to those of Composite. The results of the analysis indicated that, although the relative volatility was not constant throughout the period, there has not been a statistically significant trend up or down in the relative total risk of the Utilities Index compared to the Composite over the period 1970-2011.

The objective of the relative risk adjustment is to predict the investors' required or expected return. To do so, the persistent large component of the achieved utility return, as reflected in the equations' intercepts, which is above what the CAPM or the two variable model would have predicted, should be explicitly accounted for. The use of the calculated "raw" Canadian betas alone as an estimate of the relative risk adjustment, without consideration of the extent to which the two models have underestimated the utility return, will result in the underestimation of expected utility returns.[108]

[107] $(1.0 + 0.0075)\wedge^{12} - 1.0 = .0944 = 9.44\%$.

[108] The explicit recognition of the unexplained component of the return is consistent with the empirical observation that low beta stocks, including, but not limited to, utilities have historically earned returns higher than the CAPM predicts, with the converse observed for high beta stocks.

The equations in Tables 17 and 18 above can be solved in order to estimate a reasonable utility relative risk adjustment. To do so, values for the three independent variables (TSX equity market return, long-term Canada bond return and Treasury bill return) must be specified. For the TSX, the estimated equity market return of 11.5% developed above was used. For the long-term Canada bond return, the 4.0% yield forecast for 2013-2015 was used as a proxy. As regards the Treasury bill return, a normalized yield of 2.75% was used, reflecting the historical average yield spread between 30-year Government of Canada bonds and 90-day Treasury bills of approximately 1.25% (4.0% - 1.25% = 2.75%). In addition, estimates of the incremental utility return (i.e., the component of the return not captured by the models) are required. These estimates were based on two alternative assumptions: (1) the incremental expected utility return is the same in absolute terms as it was historically; and (2) the incremental expected utility return is in the same proportion to the total utility return as was the case historically.

Under the first assumption, the single and two variable models and the resulting indicated relative risk adjustments are as follows:

**Table 19**

| | |
|---|---|
| Equity Market Return (EMR): | 11.50% |
| Risk Free Rate (RF = T-Bill Yield): | 2.75% |
| Equity Market Risk Premium (MRP = 11.5% - 2.75%): | 8.75% |

| **Model** | **Utility Equity Beta** | **Utility Bond Beta** | **Incremental Utility Return** | **Utility Return** | **Utility Risk Premium** | **Relative Risk Adjustment** |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5)= (4)-RF | (6) = (5)/MRP |
| Single Variable | 0.465 | N/A | 3.90% | 10.70%[1/] | 7.95% | 0.91 |
| Two Variable | 0.400 | 0.46 | 2.50% | 9.32%[2/] | 6.57% | 0.75 |

[1/] 10.7% = 3.9% + 2.75% + 0.465*MRP
[2/] 9.32% = 2.5% + 2.75% +0.40*MRP + 0.46*(1.25%), where 1.25% is the maturity risk premium.

In the alternative, as noted above, the prospective incremental component of the utility return can be estimated to be in the same proportion to the total utility return as was the case historically. These proportions are approximately 30%[109] in the case of the single variable model and 20%[110]

[109] 3.9%/12.7% ≈ 30%.
[110] 2.5%/12.7% ≈ 20%.

in the case of the two variable model. In these two cases, the expected utility returns are 9.8% (single variable) and 8.5% (two variable) respectively.[111] The indicated utility risk premiums above the Treasury bill yield are 7.1% and 5.75%, corresponding to relative risk adjustments of 0.81 and 0.66, or a mid-point close to 0.75.[112]

Based on all four approaches, the indicated relative risk adjustment is in the range of 0.66 to 0.91 (mid-point of 0.78).

3.c.(v) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that regulated companies are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely, stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.[113]

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, is a partial recognition of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted historical betas are a standard means of estimating expected betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0. While the rationale for the specific adjustment formula reflects

[111] 9.8% = (2.75% + 0.465*8.75%)/(1-30%); 8.5% = (2.75% + (0.40*8.75%) + (0.46*1.25%))/(1-20%).

[112] $\frac{9.8\% - 2.75\%}{11.5\% - 2.75\%} = 0.81$; $\frac{8.5\% - 2.75\%}{11.5\% - 2.75\%} = 0.66$.

[113] See Appendix A, page A-18.

the tendency for betas in general to drift toward the market mean beta of 1.0, the adjustment is also justified on the grounds that the adjusted betas are better predictors of returns than "raw" betas.[114]

The following table presents recent reported Bloomberg adjusted betas for the five major Canadian utilities. Based solely on the recent Bloomberg betas, the relative risk adjustment would be approximately 0.62 to 0.64. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of 0.46 for the TSX Utilities Index shown in Table 17 above results in a relative risk adjustment of close to 0.65.[115]

**Table 20**

| Company | Bloomberg Beta |
|---|---|
| Canadian Utilities Ltd. | 0.52 |
| Emera Inc. | 0.71 |
| Enbridge Inc. | 0.62 |
| Fortis Inc. | 0.75 |
| TransCanada Corp. | 0.58 |
| **Average** | **0.64** |
| **Median** | **0.62** |

Source: Bloomberg.

The widely disseminated *Value Line* adjusted betas (based on weekly price change intervals) for the comparable U.S. utility sample provide a further indicator of the relevant risk adjustment for the benchmark BC utility. As summarized on Schedule 14, page 6 of 6, the reported *Value Line* betas for the sample of U.S. utilities have been approximately 0.675 on average for the five year periods ending 1996-2011, identical to the recent level (median of 0.675).

[114] Pablo Fernandez and Vicente Bermejo, in an article entitled *$\beta$ = 1 Does a Better Job than Calculated Betas*, May 19, 2009, find that adjusted betas (0.67 X calculated beta + 0.33 X Market Beta of 1.0) do a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.
[115] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the table below:

**Table 21**

| Relative Risk Indicator | Relative Risk Factor |
|---|---|
| Total Market Risk (Standard Deviations) | 0.65-0.70 |
| Relative Historic Returns and Betas: Canadian Utilities | 0.75-0.78 |
| Recent Bloomberg Adjusted Beta: Canadian Utilities | 0.62-0.64 |
| Long-term Adjusted Beta: Canadian Utilities Index | 0.65 |
| *Value Line* Betas: U.S. Utility Sample | 0.675 |

These results support a relative risk adjustment for the benchmark BC utility in the approximate range of 0.65-0.70.

3.d. Risk-Adjusted Equity Market Risk Premium Test Results

The equity market risk premium was previously estimated to be 7.25% to 7.5% at the forecast 4.0% 30-year Government of Canada bond yield. At an equity market risk premium of 7.25% to 7.5% and a relative risk adjustment of 0.65-0.70, the indicated equity risk premium for the benchmark BC utility i.e., FEI, is in the range of approximately 5.2% to 5.6%. Based on the risk-adjusted equity market risk premium test, the corresponding cost of equity is in the range of approximately 8.9% to 9.1% (mid-point of 9.0%).

## 4. DCF-Based Equity Risk Premium Test

4.a. Overview

The Discounted Cash Flow-Based (DCF-Based) Equity Risk Premium Test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds.

The DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by explicitly analyzing regulated company equity return data. In contrast, the risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly, that is, it focuses on the risk-free rate and returns at the overall market level. Of the components of that test, only the relative risk adjustment is derived directly from utility-specific data.

The DCF-based equity risk premium test was applied to a sample of U.S. utilities.[116] The DCF-based equity risk premium test was applied only to the sample of U.S. utilities, because its application requires a history of consensus long-term earnings growth rate forecasts, which is not available for Canadian utilities.[117]

A key advantage of the DCF-based equity risk premium test relative to the other equity risk premium tests is that it can be used to test the relationship between the cost of equity (or risk premiums) and interest rates (and/or other variables).[118] In the application of this test, relationships between utility risk premiums, long-term government bond yields, the spread between the yields on long-term utility and government bond yields and utility bond yields were examined.

4.b. Constant Growth DCF-Based Equity Risk Premium Test

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the U.S. utilities in the sample from 1998-2012Q1.[119] The construction of the monthly constant growth DCF costs of equity and the corresponding equity risk premiums is described in Appendix D.

---

[116] The selection criteria for the sample of U.S. utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.

[117] Analysts' forecasts of long-term earnings growth for Canadian utilities are currently accessible, which permits the application of the DCF test to Canadian utilities. However, there is no readily accessible history of those forecasts which would permit the application of the DCF-based equity risk premium test to a sample of Canadian utilities.

[118] Of the three equity risk premium tests conducted, the DCF-based equity risk premium test is the only one that lends itself to explicitly estimating the relationship between utility equity risk premiums (or the utility cost of equity) and interest rates.

[119] The choice of period 1998-2012Q1 reflects the years during which long-term Canada and U. S. Treasury bond yields have been broadly similar. It is also intended to balance the exclusion of periods that are dissimilar to current relationships between equity costs and government bond yields and the inclusion of sufficient observations to construct a reliable analysis.

For the sample of U.S. utilities, the constant growth DCF-based equity risk premium test indicates that the average 1998-2012Q1 utility risk premium was 5.0%, corresponding to an average long-term government bond yield of 4.9%. The data also show that the risk premium averaged 4.6% when long-term government bond yields were 6.0% or higher and 6.5% when long-term government bond yields were below 4.0%.

The table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2012Q1 constant growth analysis.

**Table 22**

| **Government Bond Yield** | **Below 4.0%** | **4.0%-5.0%** | **5.0%-6.0%** | **Above 6.0%** |
|---|---|---|---|---|
| **Utility Equity Risk Premium** | 6.5% | 5.1% | 4.6% | 4.6% |

Source: Schedule 16, page 1 of 4.

The data indicate that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

4.c. Three-Stage DCF-Based Equity Risk Premium Test

The DCF-based risk premium test was also applied using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix D. The use of the three-stage model, which assumes that, in the long run, earnings growth for the utility sample will converge to the long-term rate of growth in the economy, effectively lessens the volatility of the monthly growth rates utilized in the constant growth analysis.[120] Based on the three stage growth model, the average utility equity risk premium was 5.2% at an average 30-year government bond yield of 4.9%. The table below sets out the observed utility

[120] The standard deviation of the monthly sample I/B/E/S growth rates is approximately 0.5; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.3.

equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2012Q1 three-stage growth analysis.

**Table 23**

| Government Bond Yield | Below 4.0% | 4.0%-5.0% | 5.0%-6.0% | Above 6.0% |
|---|---|---|---|---|
| **Utility Equity Risk Premium** | 6.4% | 5.3% | 4.8% | 4.5% |

Source: Schedule 16, page 3 of 4.

4.d. Relationships between Equity Risk Premiums and Interest Rates

Using the constant growth and three-stage growth DCF models, the relationship between 30-year government bond yields (independent variable) and the corresponding utility equity risk premiums (dependent variable) was tested. The analysis indicated that, based on the constant growth model, over the 1998-2012Q1 period, on average, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 77 basis points. The results using the three-stage model showed a 65 basis point increase (decrease) in the utility equity risk premium for every 100 basis point decrease (increase) in the long-term government bond yield. [121]

The table below sets out the utility equity risk premium at various levels of long-term government bond yields based on the regressions using long-term government bond yields as the sole independent variable.

**Table 24**

| Government Bond Yield | 3.0% | 4.0% | 5.0% | 6.0% | 7.0% |
|---|---|---|---|---|---|
| **Utility Equity Risk Premium:** | | | | | |
| **Constant Growth** | 6.5% | 5.7% | 4.9% | 4.2% | 3.4% |
| **Three-stage Growth** | 6.4% | 5.8% | 5.1% | 4.5% | 3.8% |

Source: Schedule 16, pages 2 and 4 of 4.

[121] Expressed in terms of cost of equity, the cost of equity, as measured by the constant growth and three-stage DCF-based equity risk premium tests, increases (decreases) by approximately 25 to 35 basis points for every one percentage point increase (decrease) in the long-term government bond yield.

The analysis demonstrates that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

However, this specific analysis indicates that utility equity risk premiums are much more sensitive to, and the corresponding utility cost of equity much less sensitive to, long-term government bond yields than was assumed by the automatic ROE adjustment formula adopted by the BCUC in 2006 and terminated in 2009. That formula assumes that the utility equity risk premium increases/decreases by 25 basis points for every one percentage decrease/increase in the long-term Government of Canada bond yield.

The single independent variable analysis reflects only the relationship between the equity risk premium and government bond yields to the exclusion of other factors which impact on the cost of equity.

To capture the impact of other factors, corporate bond yield spreads were incorporated into the analysis. The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' risk perception or willingness to take risk. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[122] In the two independent variable regression analysis, government bond yields and the spread between long-term A-rated utility and government bond yields were both used as independent variables and the utility equity risk premium was the dependent variable. The two independent variable analysis indicates that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.

---

[122] Examples include: N.F. Chen, R. Roll, and S. A. Ross, "Economic Forces and the Stock Market", *Journal of Business*, Vol. 59, No. 3, July 1986, pages 383-403 and R.S. Harris and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, *Financial Management*, Summer 1992, pages 63-70.

Specifically, over the 1998-2012Q1 period, the constant growth analysis showed that the utility equity risk premium increased or decreased by approximately 86 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately eleven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 16, page 2 of 4). The three-stage growth DCF model indicates that the utility equity risk premium increased or decreased by approximately 70 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately seven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 16, page 4 of 4).

The two independent variables (long-term government bond yields and the long-term A- rated utility bond/government bond yield spread) can be collapsed into a single independent variable, the long-term A-rated utility bond yield. That analysis shows the utility equity risk premium rising and falling by approximately 55% to 60% of the change in the A-rated utility bond yield using the constant growth and three-stage growth models (Schedule 16, pages 2 and 4 of 4).

To further test the sensitivity of the utility cost of equity to changes in long-term government bond yields and utility/government bond yield spreads, quarterly ROEs allowed for U.S. utilities[123] were used as a proxy for the utility cost of equity. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

Initially, the risk premiums indicated by the quarterly allowed ROEs from 1998 to 2012Q1 were regressed against long-term Treasury bond yields lagged by six months.[124] The result indicated that the utility equity risk premium increased or decreased by approximately 45 basis points for every one percentage point decrease or increase in long-term government bond yields.

[123] The analysis was not performed for Canadian utilities due to the widespread use of formulas over an extended period that specified the relationship between government bond yields and allowed ROEs. Thus, the analysis would provide no independent estimate of the relationship.

[124] The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based.

When long-term A-rated utility/government bond yield spreads were added as a second independent variable, the analysis indicated that (1) the utility equity risk premium increased (decreased) by approximately 47 basis points for every one percentage point decrease or increase in long-term government bond yields; and (2) the utility risk premiums increased or decreased by approximately 27 basis points for every one percentage point increase or decrease in the long-term A-rated utility/government bond yield spread.

Collapsing the two independent variables into a single variable, long-term A-rated bond yields, and regressing those yields against the corresponding utility risk premiums (measured as the allowed ROE minus the Moody's long-term A-rated utility bond yield lagged six months), the analysis indicated that the utility risk premiums have decreased (increased) by just over 55 basis points for every one percentage point increase (decrease) in the A-rated utility bond yield.[125]

4.e. DCF-Based Equity Risk Premium Test Results

The regressions were solved using the forecast 4.0% 30-year Canada bond yield. For the 30-year A-rated utility/Government of Canada bond yield spread, a spread of 135 basis points was used.[126]

The table below summarizes the estimated relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads applying the various models to the U.S. utility sample over the 1998-2012Q1 period and the resulting equity risk premiums and costs of equity at a forecast 4.0% long-term Canada bond yield and a long-term A rated utility/government bond yield spread of 135 basis points.

[125] Details of all the regressions are found in Schedules 16 and 17. The greater sensitivity to interest rates indicated by the regressions using allowed ROEs as a proxy for the utility cost of equity compared to those using DCF costs of equity most likely reflects other models, in addition to the DCF, used by regulators in arriving at the allowed ROE. These models include risk premium models such as the CAPM, ECAPM, *ex ante* and *ex post* risk premium models, which are explicitly tied to interest rates. While the DCF cost of equity is sensitive to bond yields, it is also a function of factors unique to the equity market.

[126] Represents expectation that the spread between the yield on long-term A rated Canadian utility bonds and Government of Canada bonds will contract from recent levels (approximately 160 basis points at the end of June 2012) as measured by the spread between the yield on the Bloomberg A-rated Canadian Utility 30 Year Index and the benchmark long-term Government of Canada bond) as yields on long-term Government of Canada bonds rise.

**Table 25**

| | Coefficients | | Equity Risk Premium | Cost of Equity |
|---|---|---|---|---|
| | Government Bond | Bond Yield Spread | | |
| **Constant Growth** | | | | |
| **Single Variable** | -0.77 | n/a | 5.7% | 9.7% |
| **Two Variable** | -0.86 | 1.06 | 5.5% | 9.5% |
| **Three-Stage Growth** | | | | |
| **Single Variable** | -0.65 | n/a | 5.7% | 9.7% |
| **Two Variable** | -0.71 | 0.68 | 5.6% | 9.6% |
| **Allowed ROEs** | | | | |
| **Single Variable** | -0.46 | n/a | 6.2% | 10.2% |
| **Two Variable** | -0.47 | 0.27 | 6.1% | 10.1% |

Note: "Single Variable" refers to the regression analysis applied only to the long-term government bond yield and "Two Variable" refers to the addition of the spread variable to the regression analysis.

Sources: Schedules 16 and 17.

While the indicated sensitivities of the models to changes in long-term government bond yields vary, they support the conclusion that the utility cost of equity does not vary with (or track) long-term government bond yields to the extent that has frequently been assumed.

Table 26 below summarizes the regression results using an A-rated bond yield of 5.35% (equal to the forecast 4.0% 30-year Canada bond yield plus a spread of 135 basis points):

**Table 26**

| Model | Coefficient | Risk Premium over A-Rated Bond Yield | Cost of Equity |
|---|---|---|---|
| **Constant Growth DCF** | -0.43 | 4.0% | 9.4% |
| **Three-Stage DCF** | -0.57 | 4.2% | 9.6% |
| **Allowed ROEs** | -0.57 | 4.8% | 10.2% |

I have not given any weight to the results of the allowed ROE analysis in deriving an estimate of the utility cost of equity from the DCF-based risk premium test, as the allowed ROEs do not represent my own estimates of the cost of equity. Nevertheless, the relationships among utility equity risks premiums and bond yields established by that analysis provide further support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been embedded in most of the automatic adjustment formulas that have been used in Canada.

Based on the DCF-based regression analyses, at the forecast 30-year Canada and A-rated utility bond yields, the indicated utility cost of equity is in the range of approximately 9.4% to 9.7%, and approximately 9.6% based on all the DCF-based risk premium models.

## 5. Historic Utility Equity Risk Premium Test

### 5.a. Overview

The historic experienced market returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Similar to the DCF-based equity risk premium test, this test estimates the cost of equity for regulated companies directly by reference to return data for regulated companies. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

### 5.b. Historic Returns and Risk Premiums

As shown in Table 27 below, over the longest term available (1956-2011),[127] the average achieved utility (gas and electric combined) equity risk premiums in Canada were 4.2% and 4.8% in relation to total and income returns for long-term Government of Canada bonds respectively.[128] For U.S. gas utilities, the average historic utility equity risk premiums in relation to total and income returns on bonds over the entire post-World War II period (1947-2011) were 5.3% and 6.0% respectively. For U.S. electric utilities, the corresponding average historic utility equity risk premiums in relation to total and income returns on bonds were 4.4% and 5.1%.

[127] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.
[128] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2011.

**Table 27**

| | Utility Equity Returns | Bond Total Returns | Bond Income Returns | Utility Risk Premium Relative To: Bond Total Returns | Utility Risk Premium Relative To: Bond Income Returns |
|---|---|---|---|---|---|
| **Canadian Utilities** | 12.1% | 7.9% | 7.3% | 4.2% | 4.8% |
| **U.S. Gas Utilities** | 11.9% | 6.6% | 5.9% | 5.3% | 6.0% |
| **U.S. Electric Utilities** | 11.0% | 6.6% | 5.9% | 4.4% | 5.1% |

Source: Schedule 18.

5.c. <u>Trends in Equity Returns and Bond Returns</u>

Similar to the risk premiums for the market composite, the magnitude of achieved utility equity risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat (Schedule 18, pages 2 and 3 of 3). The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.0-12.0%. However, the achieved government bond returns (total and income) in Canada over the period of analysis, at 7.3% to 7.9%, were materially higher than the 4.0% forecast yield on 30-year Government of Canada bonds.

A reasonable approach to interpreting the historical utility equity market return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields. Table 28 derives estimates of the utility equity risk premium for the longer term from the historical average risk premiums by applying a 50% sensitivity factor to the difference between the historical average bond income returns and the forecast Government of Canada bond yield forecast. A 50% sensitivity factor comports with the lower end of the range of the sensitivities of utility equity risk premiums to government bond yield changes estimated in Section VIII.D.3.c above.

**Table 28**

| | | Canadian Utilities | U.S Gas Utilities | U.S. Electric Utilities |
|---|---|---|---|---|
| **Equity Returns** | (1) | 12.1% | 11.9% | 11.0% |
| **Bond Income Returns** | (2) | 7.3% | 5.9% | 5.9% |
| **Utility Risk Premium (RP)** | (3) = (1) – (2) | 4.8% | 6.0% | 5.1% |
| **Forecast 30-Year Canada Bond Yield (LCBY)** | (4) | 4.0% | 4.0% | 4.0% |
| **Change in Bond Yield/Return** | (5) = (4) – (2) | -3.3% | -1.9% | -1.9% |
| **Change in Utility Equity RP** | (6) = – (5) X 50% | +1.6% | +1.0% | +1.0% |
| **Utility Equity Risk Premium at 4.0% LCBY** | (7) = (3) + (6) | 6.4% | 7.0% | 6.2% |

Source: Schedule 18, page 1 of 3.

At the forecast 4.0% 30-year Government of Canada bond yield and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 6.25% to 7.5% (mid-point of estimates of approximately 6.5%).

5.d. Historic Utility Equity Risk Premium Test Results

Recognizing the inverse relationship between utility equity risk premiums and long-term government bond yields, the historic utility equity risk premium approach indicates a utility equity risk premium of approximately 6.5% at the forecast 4.0% 30-year Government of Canada bond yield. The corresponding utility cost of equity is approximately 10.5%.

## 6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility costs of equity based on the three equity risk premium methodologies are summarized below:

**Table 29**

| Risk Premium Test | Cost of Equity |
|---|---|
| Risk-Adjusted Equity Market | 9.0% |
| DCF-Based | 9.6% |
| Historic Utility | 10.5% |

None of the individual tests, as performed, yields an inherently superior estimate of the returns that an investor expects or requires. Thus, each of the methods was accorded equal weight in the estimation of the cost of equity for the benchmark BC utility, i.e., FEI.

## E. DISCOUNTED CASH FLOW TEST[129]

### 1. Conceptual Underpinnings

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. This proposition is based, in turn, on the efficient markets hypothesis, which states that the price of a stock today is determined by all of the available information about the stock. While the Dividend Discount Model, as it is now formally called, was not so named until the latter half of the twentieth century,[130] the concept of the discounted cash flow approach was first expressed in the early 20$^{th}$ century by Irving Fisher and later expanded on by J.B. Williams in his classic book, *The Theory of Investment Value* (Cambridge, Mass.: Harvard University Press, 1938) in which he stated:

> A stock is worth the present value of all the dividends ever to be paid upon it, no more, no less ... Present earnings, outlook, financial condition, and capitalization should bear upon the price of a stock only as they assist buyers and sellers in estimating future dividends.

The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity indirectly. The DCF

[129] See Appendix C for a more detailed discussion.
[130] Myron Gordon, *The Investment, Financing and Valuation of the Corporation*, Homewood, Illinois: Irwin, 1962.

model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.[131]

In simplest terms, the DCF cost of equity model is expressed as follows:

$$\text{Cost of Equity } \mathbf{(k)} = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[132]

$\mathbf{P_o}$ = current price

$\mathbf{g}$ = expected growth in dividends

There are multiple versions of the discounted cash flow model available to estimate the investor's required return on equity, including the constant growth model and multiple period models to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

## 2. Application of the DCF Test

### 2.a. <u>DCF Models</u>

To estimate the DCF cost of equity, both the constant growth model and a multiple stage (three-stage) model were used. In both cases, the discounted cash flow test was applied to the sample of U.S. gas and electric utilities selected to serve as a proxy for the benchmark BC utility (the same sample used in the DCF-based equity risk premium test), as well as to a sample of Canadian utilities.

[131] The Commission noted in the *2009 ROE Decision*, page 45, "As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific."

[132] Alternatively expressed as $D_o$ (1 + g), where $D_o$ is the most recently paid dividend.

2.b. Growth Estimates

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.[133]

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. The constant growth model was applied to the U.S. sample using two estimates of long-term growth. The first estimate reflects the consensus of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg, Reuters, *Value Line* and Zacks. The second is an estimate of sustainable growth. The sustainable growth rate represents the growth in earnings that a utility can expect to achieve as a result of the ROE it is expected to earn and the proportion of the ROE it reinvests plus incremental earnings growth achievable as a result of external equity financing. The development of the sustainable growth rates is explained in detail in Appendix C.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators, as some studies have concluded that analysts' earnings growth forecasts are optimistic. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. Three such tests are described in Appendix C. These tests indicate that the consensus of analysts' long-term earnings growth forecasts is not an upwardly biased estimate of investor expectations.

[133] In addition, any cost of equity estimate that relies on data for only a single company is subject to measurement error.

### 3. Results of the DCF Models

#### 3.a. Results for the Sample of U.S. Utilities

The constant growth model applied to the U.S. utility sample using the consensus of analysts' long-term earnings growth forecasts indicates a cost of equity of approximately 9.3% (Schedule 19). The utility cost of equity based on the sustainable growth model is approximately 8.7% (Schedule 20).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy.[134] The three-stage DCF model is fully described in Appendix C. The three-stage model applied to the sample of U.S. utilities indicates a cost of equity of approximately 9.2% (Schedule 21).

#### 3.b. Results for the Sample of Canadian Utilities

The constant growth and three-stage DCF models were also applied to the five major publicly-traded Canadian utilities.[135] The application of the constant growth model to the Canadian utilities indicated a cost of equity of approximately 11.0%; see Schedule 22. The cost of equity developed using the three-stage model indicates a cost of equity of approximately 8.6%; see Schedule 23.

[134] A three-stage, rather than two-stage, model was used, as the former incorporates the more likely assumption that investors would anticipate a gradual transition, rather than immediate shift, to the long-term perpetual growth rate.

[135] For the five major publicly-traded Canadian utilities, the consensus long-term earnings growth forecasts were obtained from Reuters, as it provided the highest number of analysts' forecasts for each company. There are no widely available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth.

### 3.c. DCF Cost of Equity

The table below summarizes the results of the DCF models applied to both the U.S. and Canadian utility samples.

**Table 30**

| | **Constant Growth** | | |
|---|---|---|---|
| | **Analysts' EPS Forecasts** | **Sustainable Growth** | **Three-Stage Model** |
| **U.S. Utilities** | 9.3% | 8.7% | 9.2% |
| **Canadian Utilities** | 11.0% | N/A | 8.6% |

Source: Schedules 19-23.

The constant growth and three-stage DCF models applied to the U.S. sample indicate a utility cost of equity of approximately 9.0%. For the Canadian utilities, the higher long-term earnings growth forecasts in conjunction with lower dividend yields lead to a wider range of DCF test results than for the U.S. utilities. Based on the mid-point of the range of the constant growth and three-stage models, the cost of equity for the Canadian utility sample is approximately 9.8%. The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%).

## F. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment that has typically been applied by Canadian regulators to the market-based tests only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard. The comparable earnings test recognizes that utility costs are measured in vintaged dollars and rates are based on accounting costs, not economic costs. In contrast, the tests for estimating the cost of attracting capital rely on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable returns standard, as well as the principle of fairness, suggests that, if competitive firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably <u>above</u> book value, the return allowed to utilities should not seek to maintain the value of utility assets <u>at</u> book value. It is critical that the regulator recognize the comparable returns standard when setting a fair return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value. The comparable earnings test, however, does. It applies “apples to apples”, i.e., a book value-measured return is applied to a book value-measured equity investment.

The principal issues in the application of the comparable earnings test are:[136]

1. The selection of a sample of unregulated companies of reasonably comparable total risk to a Canadian utility.
2. The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.
3. The need for any adjustment to the "raw" comparable earnings results if the selected unregulated companies are not of precisely equivalent risk to a utility.
4. The need for a downward adjustment for the unregulated companies’ market/book ratios.

The application of the comparable earnings test first requires the selection of a sample of unregulated companies of reasonably comparable risk to the benchmark BC utility, FEI. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of a sample of unregulated companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, capital structures, bond ratings and betas (See Appendix E).

Since the universe of Canadian unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on

[136] Full discussion in Appendix E.

Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 21 companies.

Next, since unregulated companies' returns on equity tend to be cyclical, the selection of an appropriate period for measuring their returns must be determined. The period selected should, in principle, encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be similar in terms of inflation and real economic growth. The last full business cycle, encompassing 1995-2011, may overestimate the returns on equity achievable going forward as nominal economic growth was higher, on average, than is projected for the longer term. As a result, the focus of the test was on the period 2004-2011, which commences subsequent to the 2001 downturn and includes the 2008-2009 recession. The period 2004-2011 represents an appropriate proxy for the next business cycle, as the average experienced rates of inflation and economic growth were reasonably similar to the average rates projected by economists over the next decade. The experienced returns on equity of the sample of 21 Canadian low risk unregulated companies over this period were in the range of 12.25%-13.5% (see Appendix E and Schedule 25).

The next step is to assess whether or not there is a need to adjust the "raw" comparable earnings results to reflect the differential risk of a Canadian utility relative to the selected unregulated companies. The comparative risk data (including betas and bond ratings) indicate that the unregulated Canadian companies are of higher risk than the benchmark BC utility, FEI. To recognize the unregulated companies' higher risk, a downward adjustment of 125 to 150 basis points[137] to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a high

[137] Based on the typical spread between Moody's BBB-rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas of the unregulated companies and Canadian utilities.

market/book ratio (relative to that of the overall market) could suggest returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratios of the sample of Canadian comparable unregulated companies over the both the full business cycle 1995-2011 and the shorter period 2004-2011 period were 2.3 and 2.2 times, similar to the market/book ratio of the S&P/TSX composite over the same periods and lower than the market/book ratio of the S&P 500 (see Appendix E). The similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios. As a result, a fair return on equity based on the comparable earnings test is approximately 11.0% to 12.0%.

## G. ALLOWANCE FOR FINANCING FLEXIBILITY[138]

The equity risk premium tests (Section VIII.D) and discounted cash flow tests (Section VIII.E) both indicate a "bare-bones" cost of equity for the benchmark BC utility of approximately 9.6%. The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the "fairness" principle. As indicated above, it is the normal practice of Canadian regulators to add an adjustment for financing flexibility to the estimated market-based utility cost of equity.

In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The

[138] See Appendix F for a more complete discussion.

market/book ratio of the S&P/TSX Composite averaged 2.1 times from 1995-2011; the corresponding average market/book ratio of the S&P 500 was 3.0 times.[139]

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 times is approximately 50 basis points.[140] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard. The comparable returns standard can be addressed by applying and giving weight to the comparable earnings test. Alternatively, if the comparable earnings test were not to be afforded the weight that it merits, the financing flexibility allowance applied to the market-based tests needs to be increased in order to arrive at a return that meets all three requirements of the fair return standard.

The cost of capital, as determined in the capital markets, is derived from market value capital structures. The cost of equity has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the corresponding book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on

[139] The market to book ratio of the S&P 500 includes Utilities. The market to book ratio of the S&P Industrials alone has been higher.
[140] Based on the DCF model as shown in Appendix F, footnote 2.

reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the “bare bones” cost of equity of approximately 150 basis points (See Appendix F).

A reasonable adjustment for financing flexibility to the “bare bones” cost of equity estimated solely by reference to market-based tests (that is, without reference to the comparable earnings test) would be the mid-point of the indicated range of 50 to 150 basis points. The addition of an allowance for financing flexibility of 50 to 150 basis points to the “bare-bones” return on equity estimate of 9.6%, derived from the equity risk premium and DCF tests, results in an estimate of the fair return on equity for the benchmark BC utility of approximately 10.5%.

## H. FAIR RETURN ON EQUITY FOR BENCHMARK BC UTILITY

Based on the risk premium, discounted cash flow and comparable earnings tests, the market-based cost of equity tests, a fair return on equity for the benchmark BC utility is approximately 10.5%, reflecting the following:

**Table 31**

| **Cost of Equity Test** | **“Bare-bones” Cost of Equity** | **Financing Flexibility Adjustment** | **Return on Equity** |
|---|---|---|---|
| **Risk Premium Tests:** | | | |
| Risk-Adjusted Equity Market | 9.0% | 0.50% | 9.5% |
| Discounted Cash Flow-Based | 9.6% | 0.50% | 10.1% |
| Historic Utility | 10.5% | 0.50% | 11.0% |
| **Discounted Cash Flow Test** | 9.4% | 0.50% | 9.9% |
| **Comparable Earnings Test** | N/A | N/A | 11.5% |

The fair ROE for the benchmark BC utility can be viewed as falling within a range bounded by the market-based cost of equity inclusive of the minimal allowance for financing flexibility

(10.1%) at the bottom end of the range and the comparable earnings test results (11.5%) at the upper end of the range. The specific weight to be given the comparable earnings test versus the market-based tests is largely a matter of judgment. The comparable earnings test is, in my opinion, entitled to significant weight. With preponderant weight (75%) given to the market-based tests, the fair ROE for the benchmark BC utility, i.e., FEI, is approximately 10.5%.

Alternatively, should only the market-based tests be relied upon (risk premium and discounted cash flow), a reasonable allowance for financing flexibility is 1.0%, reflecting the mid-point of a range of 0.50% to 1.50%. The lower end of the financing flexibility allowance range represents the minimum required to notionally allow a utility to maintain the market value of its investment at a small premium to book value. The upper end of the range represents full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures. The alternative approach also supports a fair ROE on the book value of common equity for the benchmark BC utility (FEI) of 10.5%.

# IX. DEEMED CAPITAL STRUCTURE AND DEEMED DEBT MATTERS

## A. CONTEXT

In the MFR, the Commission identified a number of issues related to deemed capital structure and deemed debt that it wished to have addressed in this proceeding. This section responds to each of these issues as requested by the Commission. As all utilities in BC are regulated on the basis of a deemed capital structure, the focus of this section is on the scenarios which might warrant a deemed cost of debt.

## B. APPLICABLE CIRCUMSTANCES FOR A UTILITY TO UTILIZE A DEEMED CAPITAL STRUCTURE WITH A DEEMED DEBT

As noted above, all utilities in British Columbia are regulated on the basis of a deemed capital structure, that is, the Commission deems an appropriate common equity ratio for the utility. The debt ratio is also deemed, as it is simply the residual between 100% and the deemed common equity ratio. However, the deemed debt component typically incorporates actual debt issues whose cost rates can be objectively observed and determined.

The actual debt issues that comprise the debt component may consist of issues that have been made directly into the public market or by private placement to third party institutions such as banks or insurance companies, or they may be non-arms length issues between a utility and an affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with cost rates that are based on market conditions.

Debt issued by the utility to a parent company may mirror an actual third-party issue made by the parent company (as has been the case for PNG (N.E.)). In that case, the parent company issues the debt, and the utility subsidiary (a legal entity) enters into an arrangement with the parent company for a specific portion of that debt issue, with the same terms as the third-party issue.[141] Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent.[142]

In some cases, debt issued by the parent company may be allocated to a stand-alone utility division. This is the case, for example, for the Fort Nelson division of FEI. FEI effectively allocates to the Fort Nelson division the total amount of debt required to balance Fort Nelson's rate base and deemed capital structure, and the embedded cost of debt for the Fort Nelson division is identical to that of FEI.[143] Arguably, the cost of debt of the Fort Nelson division is "deemed" in the sense that, as a very small natural gas distribution operation which resides within FEI (not a separate legal entity), it does not have any debt issues of its own; its cost of debt is "deemed" to be the same as FEI's.

[141] This is also the approach used, for example, by ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. CU Inc. is the issuer, and ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. enter into separate arrangements with CU Inc. for specific slices of a CU issue, according to their own funding needs, but on the same terms and conditions as the CU Inc. public issue.
[142] This is the approach used by FEW, which, in turn, is similar to the approach adopted by the Régie for Gazifère Inc., which issues debt to its parent, Enbridge Inc.
[143] A similar approach is used in Alberta by ATCO Electric Inc. for its Transmission and Distribution divisions.

The concept of a "deemed cost of debt" may arise in situations where a utility raises its own debt but maintains more equity in its actual capital structure than has been deemed by the regulator or is unable to maintain an actual equity ratio equal to the deemed equity level, due to limitations on its access to debt there may be a need to "deem" a cost to be applied to the "gap" between rate base and the sum of deemed equity and actual debt. In this context, to "deem" a cost means to assign to the gap, where no actual debt exists, cost rates that are notional or not directly observable.[144]

A deemed cost of debt may be warranted where it is inefficient or uneconomic for a small utility to issue debt on a stand-alone basis. The small utility could be a separate legal entity, or a stand-alone division or distinct class of service. Where there has been actual debt issued by the legal entity in which the utility operation (e.g., a distinct class of service) resides, but the business risk profiles of the issuer and the specific utility operation (be it a separate legal entity, regulated division or distinct class of service) are materially different, a deemed cost of debt for that utility operation that differs from the issuer's cost of debt may be warranted. In such cases, the deeming of a utility-specific cost of debt is intended to ensure, consistent with the stand-alone principle, that there are no cross-subsidies among the operations of the firm. An appropriate deemed cost of debt for the regulated operation may be higher or lower than the cost of debt that is actually incurred by the issuer, i.e., the regulated operation may face higher or lower business risk than the issuer.

While, as discussed below, there are common approaches that the Commission can rely upon for the specific utilities to which a deemed debt cost might apply, the number of potentially affected utilities is relatively small,[145] and the need to approve a deemed cost of debt relatively infrequent. The individual utilities' circumstances may be different, in terms of risk, the funding requirements and appropriate terms of debt. As a result, I recommend that the Commission continue to address the cost of debt for each utility separately.

[144] This situation differs from that, for example, of the PNG utilities which have less deemed equity in their regulated capital structures than in the actual capital structure of the parent company, Pacific Northern Gas Ltd. The "gap" between the actual equity and the deemed equity is deemed to be short-term debt, and is assigned a cost that is directly observable, that is, the rate that Pacific Northern Gas Ltd. actually incurs on its operating line of credit.

[145] In contrast to Ontario, where the OEB, which has adopted a formula for establishing caps on the cost rates of affiliated debt, is charged with regulating close to 80 municipally-owned electric distribution utilities.

## C. APPROPRIATE BASIS TO CALCULATE A DEEMED INTEREST RATE (LONG AND SHORT-TERM) FOR A UTILITY WITHOUT THIRD-PARTY OR NON-ARMS LENGTH DEBT

For small utilities which do not issue third-party debt, one option is to estimate the likely stand-alone credit rating for that utility. The stand-alone credit rating is based on an assessment of both the utility's business risk and financial risk as implied by the deemed common equity ratio. Based on the utility's estimated stand-alone credit rating, the relevant costs of debt (both long and short term) can be estimated by requesting indicative spreads from investment banks or other independent funding institutions with expertise in raising debt funds for utilities and/or infrastructure projects. Alternatively, the utility itself can provide yields and spreads on new or outstanding debt issues of similarly rated entities to support its requested cost of debt.[146] There are also debt indices available which could provide an additional check on the reasonableness of proposed debt costs, depending on the indicated stand-alone debt rating. For example, PC Bond Analytics, owned by the TSX Group, maintains and regularly publishes (for a fee) yields on A and BBB rated mid-term and long-term corporate indices.

## D. TERM OF BOND FOR DEEMED INTEREST RATE

As regards what an appropriate term for deemed long-term debt might be, there is no single term that is appropriate in all circumstances. As a general proposition, the term should reflect the long-term nature of the assets. However, other considerations include:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term of the deemed debt.

[146] GlobeinvestorGOLD publishes daily bid and ask yields, which it obtains from CIBC Wood Gundy, on a multitude of outstanding corporate bonds and maintains a history of the yields on its website. GlobeinvestorGold is a subscription service which can be obtained for a nominal monthly fee.

2. The higher the risk of the specific operations, the less their ability would be to obtain "real" debt on a long-term basis, i.e., on terms longer than 10 years.[147] The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.

3. The appropriate term for the deemed debt depends on the state of the capital markets. If, as during the financial crisis, the debt market would not accommodate a long-term issue, it would not be reasonable to deem a debt cost that was reflective of the yield on a long-term issue.

Each of these considerations underscores the conclusion that, in those situations where a deemed debt cost would be appropriate, it should be determined by the Commission on a case-by-case basis. There is no "one size fits all" cost that should be determined by means of an interest automatic adjustment mechanism.

## E. APPROPRIATE CREDIT SPREAD FOR A BENCHMARK LOW RISK UTILITY

As discussed earlier, I am recommending that the Commission continue to designate FEI as the benchmark BC utility. There is no single appropriate spread for FEI. FEI issues new long-term debt periodically; the spread for a new FEI issue will be determined by the market at the time of issue and will depend on the terms and conditions in the capital market at the time.

If the Commission's objective is to have access on a continuing basis to yields on high grade Canadian utility bonds as a guide to assessing the reasonableness of proposed costs of debt for utilities for which a deemed cost of debt may be warranted, there are indices available which could serve that purpose. Yields are available by subscription from Bloomberg for A-rated

[147] For example, PNG, when it was rated BBB(low) by DBRS, would not have been able to raise debt with a term longer than 10 years.

Canadian utilities based on fair value curves for terms ranging from one year to 30 years.[148] In the alternative, daily yields are available from GlobeinvestorGold on various issues of A-rated Canadian utilities.

## F. DEEMED CAPITAL STRUCTURE AND CREDIT SPREADS

At a high level, for a utility with a given level of business risk, the higher the deemed equity ratio is, the less risk there is to bondholders, and thus, the lower the credit spread. The credit spread (market conditions and term to maturity aside) for a real issue will also be a function of the actual debt covenants (e.g., whether the debt issue is an amortizing issue or a "bullet" issue) as well as a function of other factors that determine the available cash flows (e.g., the level of ROE and non-cash expenses, particularly depreciation). There is, however, no formulaic method for determining the how the credit spread will change for a given change in common equity ratio.

## G. APPROPRIATE PORTIONS OF SHORT-TERM AND LONG-TERM DEBT IN THE DEEMED CAPITAL STRUCTURE

The issue of whether, and in what proportions, the debt should be deemed to be short-term or long-term, is only relevant in the scenarios, described above, where a deemed cost of debt may be warranted. In my view, there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt and how much should be designated as long-term debt.

As a general proposition, since the assets that regulated utilities are financing are largely long-term assets, the preponderance of the deemed debt should be long-term. A more precise estimate of the appropriate proportion of long-term versus short-term debt is more difficult.

[148] Fair value curves are derived based the term structure of the population of bonds with similar characteristics, e.g. industry and credit rating. For example, the Bloomberg Fair Value (BFV) Canada 30-Year A-rated Utility Curve, used by the OEB for purposes of implementing its cost of capital policy, is based on Canadian dollar-denominated fixed-rate bonds, issued by Canadian utility companies with ratings of A+, A, A- from S&P, Moody's, Fitch and/or DBRS. The BFV Canada 30-Year A-rated Utility Curve is derived from using an optimization model comprised of various maturities (not solely 30-year bonds) to solve simultaneously for the term structure which best fits the existing bond yield data. Fair value curves are also available for Canadian BBB-rated utility bonds for a range of terms.

Although one can look to the actual capital structures of the larger Canadian utilities with rated debt as a reference point, as Schedule 5, page 2 of 2 shows, the percentage of short-term debt (1) has varied relatively widely among individual utilities and (2) for individual utilities, has varied relatively widely from year to year. The annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues, that is, they use short-term debt until the balance is large enough to warrant a long-term debt issue (or an equity issue) of sufficient size to be economic. The differences among utilities may reflect the use of short-term debt to finance a portion of their working capital requirements. The extent to which individual utilities rely on short-term debt during the year for this purpose will depend on the seasonality of their business and the extent to which revenues lag or lead payments for goods and services. With the caveat that it reflects material year-to-year and inter-utility variations, the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1% to 2%, as Schedule 5, page 2 of 2 shows.

To my knowledge, the only regulator which has deemed a standard proportion of short-term debt component for utilities under its jurisdiction is the Ontario Energy Board. The OEB deemed a standard deemed short-term debt component for the electricity distributors on the grounds that (1) it was clear that distributors used some short-term debt; (2) short-term debt is generally less expensive than long-term debt and generally provides greater financing flexibility; and (3) while actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of electricity distributors regulated by the OEB. The 4% deemed short-term debt component that the OEB settled on in 2006 represented the actual Ontario electricity distribution industry average at the time.[149]

The 4.0% deemed short-term debt component that the OEB selected does not capture either the wide utility-by-utility variations or annual changes in the industry average. Based on 2010 data, the average and median actual short-term debt ratios for the 77 reporting Ontario electricity distributors were both lower than the deemed 4.0%, at 2.9% and 0.4% respectively, with

[149] OEB, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006, pages 9-10.

considerable variation among the reporting utilities.[150] Moreover, inasmuch as the other components of the Ontario distribution utilities' reported actual capital structures deviated materially from the deemed proportions, using the industry average short-term debt ratio to set the deemed component is questionable.[151,152]

The above observations demonstrate that there is no single right answer to what the short-term proportion of the total deemed debt component of the capital structure should be in those few cases where deeming a short-term component may be appropriate. Nevertheless, the utility industry data available indicate that the deemed percentage of short-term debt should be very small, e.g., 1% to 2% percent.

## H. APPROACH TO DETERMINING A DEEMED SHORT-TERM INTEREST RATE

To the extent that short-term debt is determined to be an appropriate part of the capital structure, the deemed interest rate can be determined in a manner similar to the deemed long-term interest rate. Specifically, a stand-alone credit rating can be assessed for the utility and the deemed short-term term debt cost estimated on the basis of that credit rating.

Three-month Bankers' Acceptances (BAs) are a common benchmark for establishing the cost of short-term debt for utilities, e.g., for credit facilities negotiated with banks, and would provide an appropriate basis for estimating a deemed short-term debt cost. Short-term debt facilities whose pricing is based on BAs typically specify the spread over BAs that the utility will incur. The applicable spreads over the BA rate will differ depending on the utility's credit rating and the market environment. To illustrate, spreads for utilities with stand-alone ratings of BBB(low) could differ by at least 150 to 200 basis points from those applicable to utilities with stand-alone ratings of A(high).

[150] The average for the quartile with the highest reported short-term debt component was 9.6%, the middle two quartiles were 1.5% and 0.1% respectively and the lowest quartile had an actual average short-term debt ratio of 0.0%.

[151] The 2010 average and median equity ratios, at 53% and 58% respectively, were well above the industry's deemed 40%.

[152] Ontario Energy Board, *2010 Yearbook of Electricity Distributors*, August 2011.

Since spreads over BAs not only differ by credit rating, but in different credit market environments, a reasonable way of estimating the deemed debt cost is to obtain real time market quotes from major banks for issuing spreads for a utility with the specified stand-alone credit rating. The average spread obtained from the banks would then be added to the three-month BA rate. Three-month BA rates are published daily on the Bank of Canada website (series V39071).

# X. GENERIC METHODOLOGY OR PROCESS FOR DETERMINING ROE AND EQUITY RATIO FOR BC UTILITIES

The Commission has requested submissions on a proposed generic methodology or process for each utility to determine its ROE in relation to the benchmark utility and its equity ratio. Since the ROE and equity ratio are inter-related, as discussed in Section IV above, I will address these two issues together.

To my knowledge, there is no generic methodology to set each BC utility's ROE and common equity in relation to the benchmark BC utility's ROE and common equity ratio. In this context, the term "methodology" means "formula". Just as the determination of the fair ROE for the benchmark utility, FEI, is not amenable to a formula, neither is there a formulaic methodology that could be used to establish the ROE for each utility in relation to the ROE for the benchmark utility. The same conclusion holds for common equity ratio. As previously discussed in Section VII.B, while one can reach qualitative conclusions regarding the relative business risks of utility sectors generically and of individual utilities, it is not possible to isolate specific business risks and assign different percentage points of equity ratio (or equity return) to them. While one can identify different categories of business risk, those risks are themselves inter-related, e.g., competitive risk impacts market risk; supply risk impacts market risk. Further, one category of business risk may have a greater impact on the business risk profile of one utility sector or one individual utility than another sector or individual utility.

As with the determination of the fair return for the benchmark utility, FEI, there are some general principles which should be observed in setting each utility's ROE and common equity ratio:

1. The overall returns (combination of ROE and common equity ratio) awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility.

2. The overall return awarded to each utility should be comparable, on a risk-adjusted basis, to the overall return that is awarded to the benchmark utility.

3. The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some of the affected utilities may not actually have credit ratings.

4. There is a trade-off between equity ratio and ROE. For a given level of business risk, the lower the common equity ratio is, the higher is the cost of equity. For example, if a utility is not fully compensated for higher business risk than the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility.[153]

There is only one regulator in North America which has recently used what might be described as a generic process to determine the equity ratios for each of the individual utilities it regulates, the AUC (and its predecessor). In this context, a generic process is distinguished from generic proceeding, where the latter simply means that the regulator set capital structures for a number of utilities in an omnibus hearing. A process, in contrast, is intended to convey that the regulator incorporates a set of common factors to establish the equity ratios for each of the utilities. The

[153] As discussed in Appendix F, there is no universally accepted methodology for calculating the trade-off between ROE and capital structure. However the approaches that are discussed therein and provided in Schedule 27 can be used as guidelines for estimating the range of trade-offs. For example, assume that the fair ROE and common equity ratio for the benchmark BC utility are 10.5% and 40% respectively, the cost of new debt is 5.35% and the corporate income tax rate is 26.25%. For a specific utility, the common equity ratio that would fully compensate for differences in risk between the specific utility and the benchmark BC utility is 45%, but the deemed common equity ratio for the specific utility is set at 40%. The three different approaches that are presented in Appendix F indicate that the ROE for the specific utility at a 40% common equity ratio should be set at a premium of approximately 55 to 80 basis points above that awarded to the benchmark utility.

process that has been used in Alberta provides some useful guidance that can be used in the determination of common equity ratios for individual BC utilities.

In Alberta, the AUC sets the common equity ratios of each of the utilities by (1) specifying a goal that it intends to achieve; and (2) considers a number of common factors to assist in achieving that goal. The AUC's objective is to set common equity ratios that "in the Commission's judgment, would allow a stand-alone utility to maintain a credit rating in the A range subject to company-specific circumstances."[154] The factors that it considers are:

1. Previously allowed common equity ratio.
2. Business risk
    a. The relative business risk of the various utility sectors in Alberta;
    b. Trends in business risk of the sectors since the previous capital structure review; and
    c. Business risks specific to individual utilities.
3. Credit environment and changes therein.
4. Credit metrics and actual credit ratings of stand-alone[155] utilities.
5. Company-specific considerations.

In contrast to the BCUC, the AUC attempts to compensate for differences in risks among the utilities that it regulates through capital structures, rather than a combination of ROE and capital structure. While this may be a reasonable objective for some utilities, there are two potential issues with this approach. First, there are some BC utilities whose business risk and size would not permit them, on a stand-alone basis, to achieve ratings in the A category, no matter how high the equity ratio.

For example, Pacific Northern Gas was rated BBB(low) by DBRS before its debt ratings were discontinued in March 2012. A BBB(low) debt rating is the lowest investment grade rating. At the end of 2012, the utility's actual common equity ratio was just below 50%; its deemed common equity ratios are currently 45% for PNG-West and 40% for both PNG (N.E.) (Fort St.

---

[154] AUC, *Decision 2009-216*, page 88. The AUC reaffirmed the importance of targeting A credit ratings in *Decision 2011-474*, pages 31 and 35.
[155] Refers to utilities which issue debt directly into the debt market independently of any affiliated companies.

John/Dawson Creek Division) and PNG (N.E) (Tumbler Ridge Division). It is unlikely that, even if the Commission were to increase PNG's deemed equity ratios to 60%, it would be able (notionally) to achieve ratings in the A category and thus to be able to raise debt at rates consistent with an A rating. Consequently, the utility would have a notional "A rating" capital structure without the concomitant access to debt capital and debt cost of an A rated utility. Overall, the cost of capital would be lower if the Commission were to continue its current practice for such utilities, that is, allow common equity ratios that are sufficient to achieve (notionally) an investment grade debt rating, and reflect the utilities' total risk difference with the benchmark BC utility in the ROE.

Second, in most cases where the regulator deems an equity ratio for a utility, there is an expectation that the utility will maintain an actual equity ratio at least as high as the deemed level. It cannot be assumed that a particular utility would either be able or willing to commit and maintain the additional equity that might be required for the notional "A rating" equity ratio.

In the context of this proceeding, the Commission will have an opportunity to canvas issues that are salient to capital structure decisions for all the BC utilities, e.g., relative business risks of utility sectors, the credit environment, the actual credit metrics of utilities that raise their own debt and their corresponding debt ratings. These factors should provide some insight into a range of capital structures that would be reasonable for individual utilities. Nevertheless, in each case informed judgment will be required.[156] Further, each utility has its own unique business risks and circumstances. Each utility should be afforded an opportunity, whether within its own revenue requirements proceeding or in an omnibus proceeding, to provide the evidence it believes is germane to, and supportive of, its requested capital structure and ROE relative to the benchmark utility.

[156] While the AUC considered and discussed each of the factors listed above, its ultimate decisions regarding each utility's common equity ratio were substantially a matter of the AUC's own judgment.

# XI. GENERIC COMPANY-SPECIFIC MATTERS

In Order G-72-12, as part of the MFR on Capital Structure Matters, the Commission requested submissions on "generic company-specific adjustments for: effective income tax rates, size of utility, level of contributed assets, and company-specific or sector-specific factors." This section addresses the Commission's request.

## A. EFFECTIVE INCOME TAX RATES

In Canada, most investor-owned utilities are regulated on the basis of flow-through income taxes.[157] That means they are only allowed to collect in their revenue requirement income taxes that are currently payable. For utilities that are undergoing periods of significant growth, this may mean that the income tax allowance in the revenue requirement is very low or potentially nil for an extended period. In other words, the utility's effective income tax rate is lower than the statutory rate. The effective tax rate can be calculated as the income tax payable divided by the pre-tax book income. The low to nil income tax allowance arises because the capital cost allowances on certain categories of utility plant exceed book depreciation, reducing income taxes payable. For government-owned utilities that are tax-exempt,[158] the effective income tax rate is zero.

There are two impacts of a low effective income tax rate that are relevant to capital structure decisions. First, the lower the effective income tax rate is, the more variable are after-tax earnings. When a utility pays corporate income taxes at the full statutory rate, any unanticipated reduction in pre-tax earnings (arising, for example, from lower than expected sales or higher than expected expenses), is shared between the utility and the taxing authorities. When the utility pays no income taxes, the full short-fall in pre-tax earnings is borne by the utility. The higher volatility in earnings arising from a low or nil effective corporate income tax rate is a factor that,

[157] In the U.S. most utilities are regulated on the basis of deferred taxes, which means that they collect in their revenue requirement, an allowance for taxes which is effectively based on book, rather, than tax depreciation expense.

[158] Not all government-owned utilities are tax-exempt; some, as in Ontario, make payments in lieu of income taxes which mirror the corporate income taxes paid by investor-owned utilities.

in isolation, warrants a higher common equity ratio than where taxes are payable at the full corporate income tax rate.[159]

The second impact of a low effective income tax rate relates to the impact on pre-tax credit metrics, such as the EBIT coverage ratio.[160] The lower is the income tax allowance, the lower is a utility's EBIT coverage ratio and other pre-tax credit metrics. A higher common equity ratio is required at a low or nil effective income tax rate in order to achieve the same level of credit metrics achievable when income taxes are collected in the revenue requirement at the full statutory rate. [161]

In both Decision 2009-216 and Decision 2011-474, the AUC awarded deemed common equity ratios two percentage points higher to utilities which were tax exempt or *de facto* non-taxable,[162] citing both the higher volatility of earnings and lower pre-tax interest coverage ratios of non-taxable utilities compared to otherwise equivalent taxable companies.[163]

[159] This phenomenon is more generally applicable to all taxable utilities, as the statutory tax rates in Canada have declined materially over the past 15 years. For example, the combined federal/provincial income tax rate in British Columbia was 45.6% 15 years ago. In 2013, the statutory rate will be 25%. Lower corporate income taxes enacted between 2004 and 2009 were one factor that the AUC considered in *Decision 2009-216* (page 106) in adopting a 2% across the board increase in allowed common equity ratios.

[160] As previously defined, Earnings before Interest and Taxes divided by Interest. Other pre-tax coverage ratios that the debt rating agencies consider are Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA) to Interest and EBITDA to Total Debt.

[161] Assuming FEI's embedded cost of debt of 6.9% forecast for 2013, its current capital structure ratios (60% debt/40% common equity ratio) and current allowed ROE of 9.5%, at an income tax rate of 0%, an adjustment of approximately seven percentage points to the equity ratio is required in order to achieve the same EBIT interest coverage ratio implied at an income tax allowance at the full 2013 combined federal/British Columbia statutory rate of 25%.

[162] FortisAlberta was found to be *de facto* non-taxable as it was currently non-taxable and expected to be so for at least the near-term future, thus qualifying for the additional two percentage points.

[163] The Canadian Radio-television and Telecommunications Commission (CRTC) has allowed higher common equity ratios for telephone companies that did not incur income tax expense than for telephone companies that did. In Telecom Decision CRTC 98-2, the CRTC stated: "The Commission considers that, since MTS [MTS NetCom Inc.] does not currently incur income tax expense, the company's rates would not permit it to achieve interest coverage and a debt rating commensurate with its peers without recognition in the capital structure of the company's different circumstances." The CRTC also allowed Telus Inc. to utilize a higher common equity ratio than adopted for other major telephone companies due to its non-taxable status (60% versus 55%).

## B. SIZE

In the assessment of investment risk, size has two dimensions which should be considered in the determination of specific utilities' ROEs and common equity ratios:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. Negative events are likely to have a greater impact on the earnings or viability of a small company. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility. Even for a small utility with the same customer base in terms of proportions of residential, commercial and industrial customers as a large utility; the loss of a single customer within a customer class would have a greater impact on a small utility.

2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. As recently as June 2009, DBRS considered size to be a factor in its ratings of FortisBC Inc., referring to its comparatively small size relative to the dominant utility in the province, BC Hydro, as a "Challenge". At the time, FortisBC Inc. had total assets of slightly over $1 billion and was rated BBB(high).[164]

Regulators have recognized small size as a factor in establishing capital structures and ROEs for utilities. The AUC stated in *Decision 2011-474,* page 43, "Due to its small size, AltaGas is more

[164] DBRS, *Rating Report: FortisBC Inc.*, June 5, 2009. FortisBC was upgraded by DBRS to A(low) in October 2010.

risky than ATCO Gas." As a result, the AUC set the deemed common equity ratio for AltaGas Utilities at 43% compared to ATCO Gas' 39%. The Régie considers Gazifère Inc. to be of above average risk in particular due to its small size and competition with electricity in Québec. The Régie adopted an equity risk premium for Gazifère of 0.25% to 0.50% above that applicable to a benchmark distributor on a common equity ratio of 40%.[165]

Studies on small size and returns conducted by Ibbotson Associates Inc. have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historic returns for companies of different sizes. The analyses indicate that small companies tend to exhibit higher betas than larger companies.[166]

To illustrate, in the Ibbotson classification of U.S. stocks for 2011, the median utility in the U.S. sample used to estimate the fair return for FEI would be a Mid-Cap stock (market value of equity capitalization in the range of approximately $1.6 billion to $6.9 billion). By comparison, for example, companies with market values of equity less than $400 million would be Micro-Cap stocks. The betas of Micro-Cap stocks have been approximately 0.30 higher than those of Mid-Cap stocks. In the context of the CAPM, an incremental beta of 0.32, when applied to a market risk premium of 7.25%, indicates an incremental equity risk premium of over 200 basis points (7.25% x 0.32) for a Micro-Cap company relative to a Mid-Cap stock.

While these analyses were performed using all stocks, not utilities specifically, Ibbotson has also performed an industry-by-industry analysis which shows that the conclusions regarding the firm size effect apply to regulated companies as well as unregulated companies. Based on 82 years of data, Ibbotson's analysis demonstrated that the returns for small publicly-traded electric, gas and sanitary utilities have been approximately 1.5 and 3 percentage points higher on a compound and arithmetic average basis respectively than those of large utilities.[167]

---

[165] Régie de l'énergie, *Decision: Demande relative au renouvellement du mécanisme incitatif, à la fermeture réglementaire des livres pour la période du 1er janvier 2009 au 31 décembre 2009, à l'approbation du plan d'approvisionnement pour l'exercice 2011 et à la modification des tarifs de Gazifère Inc. à compter du 1er janvier 2011*, D-2010-147, November 26, 2010.
[166] Morningstar, *Ibbotson SBBI 2012 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2011*, pages 85-107.
[167] Morningstar, Ibbotson SBBI, *2008 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2007*, pages 154-155.

In sum, the above considerations indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual BC utilities.

## C. CONTRIBUTED ASSETS

Contributed assets, customer contributions, or contributions in aid of construction (CIAC), refer to assets which a utility owns, operates and manages, but which are financed by customers. The proportion of contributed assets to total capital for different utilities will depend in part on their investment policy and in part on the characteristics of the service territory. With respect to the former, investment policy determines how much of the investment in new connections the utility will make and how much the customer is required to make.

Most utilities in Canada have some proportion of their assets financed by customer contributions. The proportions vary widely among utilities, but for most large Canadian utilities outside Alberta, the proportion of customer contributions to total utility capital has been relatively small (i.e., less than 5% of the total utility capital). In Alberta and for some utilities in BC, the proportion is quite high, in some cases in excess of 30%.[168]

To put this in perspective, assume two utilities, one with no contributed assets and one whose contributed assets constitute 20% of gross rate base. Both have deemed common equity ratios of 40%. If contributed assets are included in the capital structure as a source of financing, the utility with no contributed assets has an effective equity ratio of 40%; the utility which has 20% of its assets financed with contributions has an effective equity ratio of 32%, as illustrated in the table below.

[168] For perspective, FEI's contributed assets as a percent of gross rate base are approximately 4.5%; FortisBC's are approximately 8% and PNG-West's are approximately 4%, but FEVI's are close to 30% and PNG (N.E.) (Tumbler Ridge Division)'s are close to 40% of the total utility capital.

**Table 32**

| | Utility A | Utility B |
|---|---|---|
| **Gross Rate Base** | 200,000 | 200,000 |
| **CIAC** | - | 40,000 |
| **Net Rate Base** | 200,000 | 160,000 |
| **Deemed Capital Structure:** | | |
| **60% Debt/40% Equity** | | |
| **Debt** | 120,000 | 96,000 |
| **CIAC** | - | 40,000 |
| **Equity** | 80,000 | 64,000 |
| **Total** | 200,000 | 200,000 |
| **Capital Structure Ratios Inclusive of CIAC:** | | |
| **Debt** | 60.0% | 48.0% |
| **CIAC** | 0.0% | 20.0% |
| **Equity** | 40.0% | 32.0% |

As regards risk and capital structure, the higher is the proportion of contributed assets to total capital, the higher is a utility's operating leverage, all other things equal. Since a utility operates and manages the contributed assets, it will incur operating and maintenance expenses to do so, just as if those assets were financed by investor-supplied capital.

Table 33 below provides an illustration of the greater sensitivity of the ROE to an unanticipated change in operating and maintenance (O&M) expense for a utility with 20% of its rate base funded by contributed assets (CIAC) than a similarly situated utility with no CIAC. In this example, the two hypothetical utilities have the same level of O&M expense as the only difference is that Utility A has no CIAC funding its assets and Utility B has 20% of its rate base funded by CIAC. Both utilities have a deemed common equity ratio that is 40% of rate base net of CIAC. In this illustration, a 5% unanticipated increase in O&M expense reduces the actual ROE below the allowed ROE by a wider margin than it does for a utility with no CIAC. In other words, the greater CIAC introduces greater potential volatility in actual earnings.

**Table 33**

| | Utility A<br>No CIAC | Utility B<br>CIAC 20%<br>Rate Base |
|---|---|---|
| **Gross Rate Base** | **$200,000** | **$200,000** |
| **Debt at 60%** | 120,000 | 96,000 |
| **Equity at 40%** | 80,000 | 64,000 |
| **CIAC** | - | 40,000 |
| **Revenue Requirement:** | | |
| Operating and Maintenance Expense | 30,000 | 30,000 |
| Depreciation and Amortization (6%)[1/] | 12,000 | 9,600 |
| Interest Expense (6%) | 7,200 | 5,760 |
| ROE (10%) | 8,000 | 6,400 |
| Income Tax at 25% | 2,667 | 2,133 |
| **Total Revenue Requirement** | **$ 59,867** | **$ 53,893** |
| **O&M Increases by 5%** | | |
| **Revenue** | **$ 59,867** | **$ 53,893** |
| **Less:** | | |
| O&M | 31,500 | 31,500 |
| Depreciation & Amortization | (12,000) | ( 9,600) |
| Interest Expense | ( 7,200) | ( 5,760) |
| **Operating Income** | **9,167** | **7,033** |
| **Income Tax at 25%** | ( 2,292) | ( 1,758) |
| **Net Income** | **$ 6,875** | **$ 5,275** |
| **Return on Equity** | **8.6%** | **8.2%** |

[1/] For illustrative purposes, depreciation expense is 6% of rate base funded by investor-supplied capital.

All other things equal, a utility with a relatively high proportion of contributed assets to total capital requires a higher common equity ratio than a utility with no contributed assets to achieve a similar degree of operating leverage and potential variability in ROE.[169] There is no "bright line" for determining at what level or proportion of total assets customer contributions become a material enough concern to warrant a higher common equity ratio than would be the case in the absence of such contributions. If a specific utility's proportion of contributions to gross rate base is well outside the norm, it would be reasonable to consider that factor in establishing that utility's regulated common equity ratio.

[169] In *Decision 2011-474*, page 92, the AUC found that CIAC-funded assets contribute to business risk. "In general, business risk would be expected to rise in proportion to assets. The Commission agrees with the Utilities that, without an increase in equity, CIAC-funded assets would cause an increase in financial risk and operating leverage risk."

# Appendices
# to
# TESTIMONY

**ON**

# COST OF CAPITAL

**FOR THE**

# FORTISBC UTILITIES


Prepared by

**KATHLEEN C. MCSHANE**


foster associates

August 2012

# APPENDICES

**APPENDIX A:** **ADJUSTED EQUITY MARKET RISK PREMIUM TEST**

**APPENDIX B:** **SELECTION OF U.S. LOW RISK UTILITY SAMPLE**

**APPENDIX C:** **DISCOUNTED CASH FLOW TEST**

**APPENDIX D:** **DCF-BASED EQUITY RISK PREMIUM TEST**

**APPENDIX E:** **COMPARABLE EARNINGS TEST**

**APPENDIX F:** **FINANCING FLEXIBILITY ADJUSTMENT**

**APPENDIX G:** **QUALIFICATIONS OF KATHLEEN C. MCSHANE**

**APPENDIX A**

# ADJUSTED
# EQUITY MARKET RISK PREMIUM TEST

## 1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F} \quad + \quad \boldsymbol{\beta}(\mathbf{R_M} - \mathbf{R_F}),$$

Where:

| | | |
|---|---|---|
| $\mathbf{R_F}$ | = | risk-free rate |
| $\boldsymbol{\beta}$ | = | covariability of the security with the market (M) |
| $\mathbf{R_M}$ | = | return on the market |

The model is based on restrictive assumptions, including:

**a. Perfect, or efficient, markets exist where,**

(1) each investor assumes he has no effect on security prices;
(2) there are no taxes or transaction costs;
(3) all assets are publicly traded and perfectly divisible;
(4) there are no constraints on short-sales; and,
(5) the same risk-free rate applies to both borrowing and lending.

**b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.**

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance }(R_E, R_M)}{\text{Variance }(R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

The "father" of modern portfolio theory (and winner of the Nobel Prize for Economics) Harry Markowitz has stated that "The CAPM is a thing of beauty. Thanks to one or another counterfactual assumption, it achieves clean and simple conclusions."[1] A key counter-factual assumption is the investor's ability to borrow unlimited amounts at the risk-free rate. He concludes that because key assumptions of the model do not hold, then it no longer holds that expected returns are linearly related to beta. He does state that CAPM should be taught, despite its drawbacks. According to Dr. Markowitz:

> It is like studying the motion of objects on Earth under the assumption that the Earth has no air. The calculations and results are much simpler if this assumption is made. But at some point, the obvious fact that, on Earth, cannonballs and feathers do not fall at the same rate should be noted and explained to some extent.[2]

## 2. RISK-FREE RATE

a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is <u>highly</u> correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

[1] Markowitz, Harry M., "Market Efficiency: A Theoretical Distinction and So What?", *Financial Analysts Journal*, September/October 2005, page 29.
[2] *Ibid.*, pages 28-29.

(1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government was in a surplus position from 1997/1998 to 2007/2008 (ten years), which reduced its financing requirements.[3] In 2008/2009, despite a budget deficit, the federal debt/GDP ratio stood at 29%, its lowest level since 1980/81, and well below the 1995/1996 peak of 68%. In the twelve months ending March 2012, Government of Canada bonds accounted for a little over one-quarter of total Canadian dollar bonds outstanding,[4] compared to almost half in 1996.[5] However, the demand for long-term government securities by institutions that are "buy and hold" investors and that match the duration of their assets and liabilities (e.g., pension funds and insurance companies) has not declined. Thus, there is a potential for the prices of long-term government bonds to incorporate a scarcity premium reflecting an imbalance between demand and supply.

Further, with the credit downgrades of a number of advanced economy sovereign issuers in the last several years, the pool of high grade sovereign debt globally has shrunk over the past several years. The Government of Canada is one of relatively few advanced economy debt issuers with AAA ratings, and the third largest economy with AAA ratings by all three ratings agencies, in a global capital market with a high demand for safe haven assets. However, Canada is a relatively small economy, and accounts for only about 4% of the world capital market, and the supply of its debt is limited.[6] As a result, the recent yields on long-term Government of Canada debt are likely to reflect a scarcity premium.

[3] Following budget deficits of $55.6 billion and $33.4 billion in fiscal years 2009/2010 and 2010/2011 respectively, the Department of Finance's Budget 2012 (March 29, 2012) anticipated declining budget deficits through 2014/2015, with a small surplus ($3.4 billion) in 2015/2016. Further, it forecast the deficit for the fiscal year 2011/2012 had declined to $24.9 billion, compared to the Department's November 2011 estimated deficit of $31 billion. The Department of Finance's projections show the federal debt to GDP peaking at approximately 35% in 2012/13, then declining to 28.5% in 2016/2017, in line with its pre-recession (2008/2009) level.

[4] Includes provincial, municipal, corporate, foreign issuer, and term securitization bonds.

[5] Statistics Canada, www.statcan.gc.ca

[6] The demand for the February 2012 issue of $3 billion in U.S. dollar-denominated five-year bonds by the Government of Canada was outstripped by supply by a factor of 3-to-1.

(2) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, the wake of the subprime mortgage crisis commencing in late 2007, and the ongoing sovereign debt crisis in Europe, investors shifted to the safe haven of government securities perceived as default-free, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM, which relies heavily on long-term average achieved equity risk premiums, captures the lower government bond yields, but not the corresponding increase in the equity risk premium.

(3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. Changes in the risk of the "risk-free" security introduce further complexity to the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

c. The radical change in Canada's fiscal performance since the mid-1990s contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada measured using total bond returns were squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to the historical total returns on those securities indicate that the historical returns on long-term Government of Canada bonds overstate the forward looking risk-free rate. The estimate of the equity market risk premium using historical data as a point of departure needs to recognize the much higher government bond returns historically than the forecast risk-free rate.

d. Total returns on government bonds include capital gains and losses resulting from changes in interest rates over time. The income return on government bonds, in contrast, reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.[7]

## 3. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

### a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance,* Boston: Irwin/McGraw Hill, 2006 (p. 151), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

[7] As stated in Ibbotson *SBBI 2012 Valuation Yearbook* (page 55), "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for estimation of the cost of equity is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

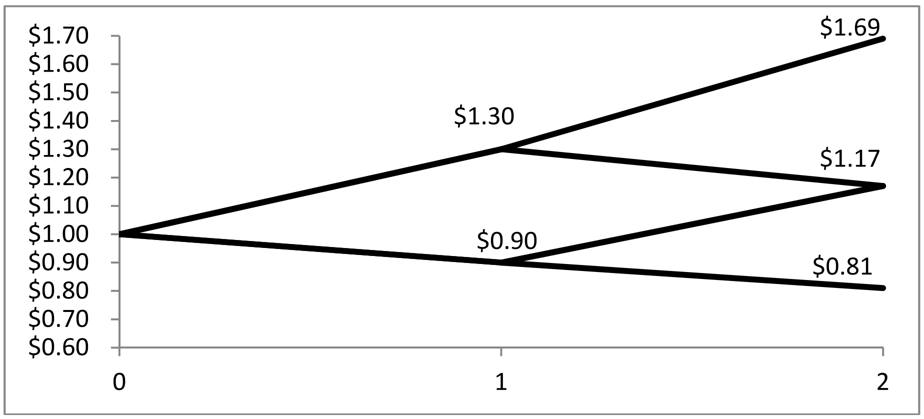
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

*Triumph of the Optimists: 101 Years of Global Investment Returns* by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

**b. Illustration of Why Arithmetic Average Should be Used**

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2012,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-3.
>
> **Graph 5-3** **Growth of Wealth Example**
>
> 
> 
>
> The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:
>
> $$[(1+0.30) \times (1-0.10)]^{1/2} - 1 = 0.082$$
>
> However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:
>
> | | | | |
> |---|---|---|---|
> | | (0.25 x $1.69) | = | $0.4225 |
> | + | (0.50 x $1.17) | = | $0.5850 |
> | + | (0.25 x $0.81) | = | $0.2025 |
> | | Total | | $1.2100 |

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean.

..........................................................................................................................

$$\$1 \times (1+0.10)^2 = \$1.21$$

..........................................................................................................................

The geometric mean, when compounded, results in the median of the distribution:

..........................................................................................................................

$$\$1 \times (1+0.082)^2 = \$1.17$$

..........................................................................................................................

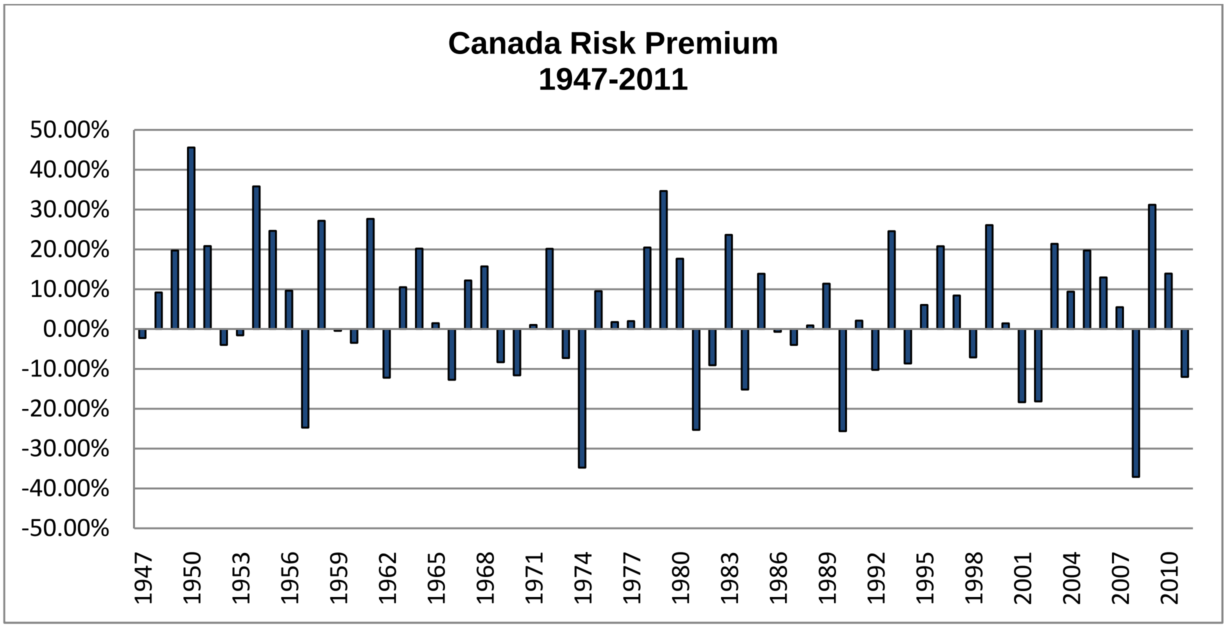
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

### c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historical post-World War II annual risk premiums (measured as the equity market return less the corresponding year's long-term government bond income return). The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[8]

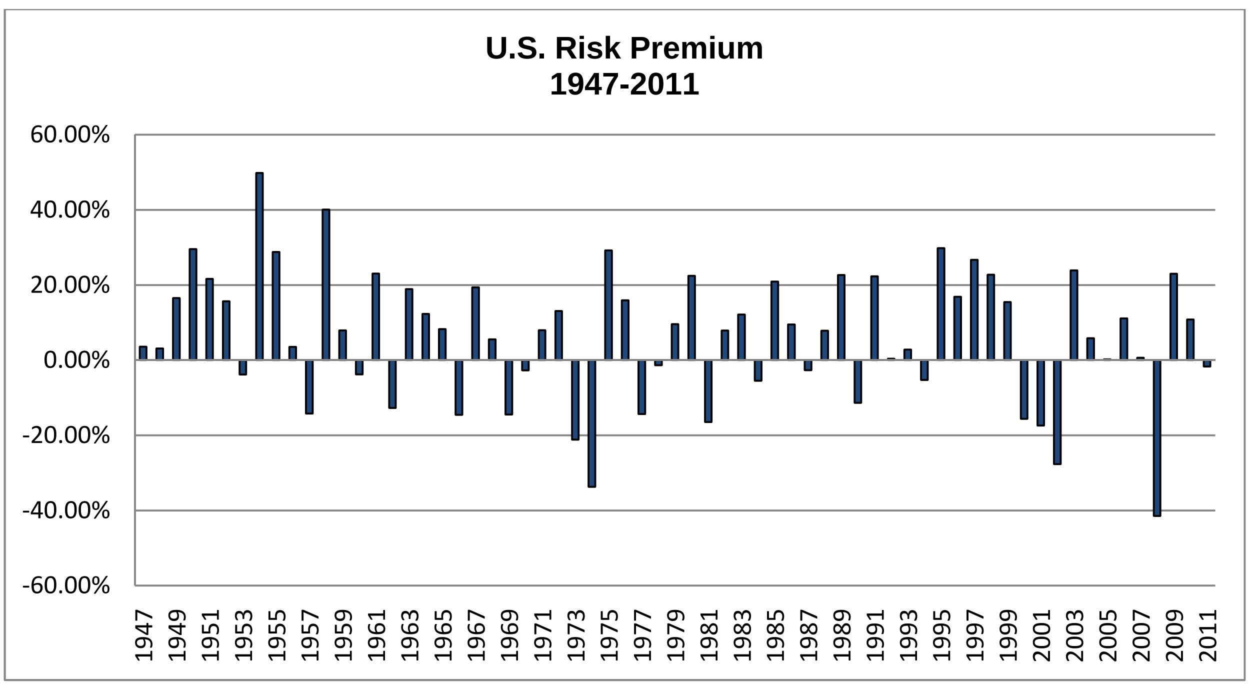
[8] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlations between the current year's risk premium (equity market return less bond income return) and that of the prior year for the period 1947-2011 are -0.052 for Canada and -0.029 for the U.S. For the period 1924-2011 the serial correlation in Canada is 0.119. For the period 1927-2011 the serial correlation in the U.S. is 0.020. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

**Chart A - 1**




Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2011*.

**Chart A - 2**




Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2012 Yearbook.*

## 4. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[9] The next largest sector, financial services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table A-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

**Table A - 1**

| | 1980 | 2000 |
|---|---|---|
| Information Technology | 0.9% | 24.1% |
| Telecommunication Services | 4.8% | 6.5% |
| Financial Services | 13.5% | 24.1% |
| Total | **19.2%** | **54.7%** |

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2011, the energy and materials (largely mining) sectors accounted for over 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 80% of the total market value of the S&P/TSX Composite.

[9] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes “the conglomerates sector”, which also contained stocks with significant commodity exposure.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at year-end 2011 illustrates the difference.

**Table A - 2**

| Sector | S&P/TSX Canada | S&P 500 U.S. |
|---|---|---|
| Consumer Discretionary | 4.0% | 10.7% |
| Consumer Staples | 2.8% | 11.5% |
| Energy | 27.1% | 12.3% |
| Financials | 29.4% | 13.6% |
| Health Care | 1.4% | 11.9% |
| Industrials | 5.8% | 10.7% |
| Information Technology | 1.3% | 19.0% |
| Materials | 21.1% | 3.5% |
| Telecommunication Services | 5.2% | 3.0% |
| Utilities | 2.0% | 3.9% |

Source: *TSX Review,* December 2011 and www.standardandpoors.com, (January 17, 2012).

Even within the remaining areas of the Canadian market (the less than 25% accounted for by the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index, compared to the largest stock in the S&P 500 at that time (General Electric), which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. At the end of December 2011, the largest twenty stocks accounted for approximately 50% of the total market capitalization of the S&P/TSX Composite Index. Of the twenty, six (20% of Composite Index market capitalization) were financial and nine

(22% of Composite Index market capitalization) were resource (energy and mining) companies.[10] The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the Composite Index regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some of these concerns when they overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2011 there were 253 companies in the S&P/TSX Composite Index.

The addition of income trusts at the end of 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more

[10] By comparison, the largest 20 stocks in the S&P 500 accounted for 33% of the total index market capitalization, with no single sector represented among the top 20 stocks accounting for more than 10% of the total market capitalization of the index.

than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. From 1998 (the first year for which returns were reported) to 2005, the annual compound total return for the S&P/TSX Capped Income Trust Index was 19%, compared to 8.5% for the S&P/TSX Composite Index.[11] As income trusts significantly outperformed "conventional" equities, their exclusion from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.[12]

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[13] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[14] which supported

[11] The annual compound total return for the S&P/TSX Income Trust Index (previously the Capped Income Trust Index) over the 1998-2011 period averaged 14.8%, compared to 6.5% for the S&P/TSX Composite Index.
[12] With the change to the income tax treatment of income trusts announced in October 2006 (effective January 1, 2011), most of the income trusts in the S&P/TSX Composite Index have converted back to conventional corporations.
[13] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.
[14] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

the removal of the cap.[15] At that time, the *Globe and Mail* reported that the removal of the foreign content cap was expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[16] The Foreign Property Rule was eliminated in 2005.

Effectively, the combination of mediocre returns and small size of the Canadian market relative to the total global market put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. From this perspective, historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases have declined from their 2007 peaks, in 2011 they were approximately $493 billion, of which over 70% are U.S. stocks.[17] As of 2011Q3, although the total percentage of foreign assets in trusteed pension funds was approximately 30%, the percentage of foreign equity to total equity was close to 50%.[18] In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Just over 40% of Canadian portfolio investment in foreign equities at the end of 2011 was in the U.S.[19]

---

[15] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[16] Rob Carrick, *Finance: Your Bottom Line*, www.globeandmail.com, February 23, 2005.
[17] Statistics Canada, *International Transactions in Securities, March 2012*, May 2012, Table 12-2.
[18] Based on market value. Statistics Canada, Table 280-0003, data through September 2011.
[19] Statistics Canada, *Canada's International Investment Position – Fourth quarter 2011,* March 2012, Table 21-1. The U.S. portion of Canadian direct investment abroad at the end of 2011 was approximately 41%.

## 5. TRENDS IN PRICE/EARNINGS RATIOS

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[20] of the S&P 500 averaged 13.7 times from 1926-1988, with no discernible upward trend.[21] From 11.6 times in late 1988, the P/E ratio gradually rose, peaking at over 46 times in early 2002. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[22] By mid-2006, the P/E ratio had fallen to approximately 17 times.

As the market advanced from 2006 to late 2007, the P/E ratio expanded; when the S&P 500 was at its pre-crisis peak, the P/E ratio reached 22 times. As both the market and earnings collapsed during the financial crisis, the P/E ratio soared to above 120 times during the second quarter of 2009.[23] With recovery in both earnings and the equity market, the P/E ratio fell. At the end of March 2012, the P/E ratio of the S&P 500 was approximately 16 times, compared to the long-term (1926-2011) average of approximately 16.6 times.

[20] Price to trailing twelve month "as reported" earnings.
[21] The average P/E ratio from 1947-1988 was 13 times.
[22] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.
[23] Based on operating earnings, the increase was much less extreme; the P/E ratio based on operating earnings reached 27 times during third quarter 2009.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1926 and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.1% from 1926-1988. The corresponding average return from 1926-2011 was 11.8%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1926-2011 period than over the 1926-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.3% over the entire 1947-2011 period. In other words, the increase in P/E ratios during the 1990s did not result in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable.

A review of equity returns in Canada indicates similar results. The 1926-1988 arithmetic average return for the Canadian equity market was 11.8%, higher than the average 1936-2011 return of 11.2%. Similarly, the 1947-1988 equity market return of 12.9% was higher than the 1947-2011 return of 11.8%. There is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward.

# 6. RELATIVE RISK ADJUSTMENT

## a. Beta

The body of evidence on CAPM leads to the conclusion that, while betas[24] do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

---

[24] The beta is equal to:

$$\frac{\text{Covariance}\,(R_E, R_M)}{\text{Variance}\,(R_M)}$$

Where: $R_E$ = Return on the individual stock or portfolio of stocks and $R_M$ is the return on the equity market.

Alternatively, the beta can be expressed as:

Standard Deviation of $R_E$ / Standard Deviation of $R_M$ X Correlation Coefficient ($\rho$)

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

Fama and French stated in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

The Fama French study found that the relationship between beta and average return is much flatter than the CAPM would predict. Specifically, based on analysis covering 1928 to 2003 for the U.S. market, they showed that the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return.[25]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.

[25] Fama and French developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM. The additional factors are size and book to market.

> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[26]

In a May 2009 survey, "Betas Used by Professors: A Survey with 2,500 Answers," Dr. Pablo Fernandez cites nine different problems with betas including: (1) they have little correlation with stock returns; (2) a beta of 1.0 has a higher correlation with stock returns for many companies; (3) frequently we don't know if the beta of one company is higher than another; (4) the correlation coefficients of the regressions used to calculate the betas are very small; (5) and the relative magnitude of betas often makes very little sense. Based on the issues cited, Dr. Fernandez reaches two findings: the beta calculated with historical data is not a good approximation to the company's beta and the beta of a company (a common figure for all investors) does not exist. The two conclusions, Dr. Fernandez states, imply the CAPM does not work. Ultimately, Dr. Fernandez concludes: "We argue, as many professors mention, that historical betas (calculated from historical data) are useless to calculate the required return to equity (footnote omitted), to rank portfolios with respect to systematic risk, and to estimate the expected return of companies."

In an article released at approximately the same time entitled "β = 1 Does a Better Job than Calculated Betas", May 19, 2009, Dr. Fernandez and co-author, Vicente Bermejo find that

[26] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

adjusted betas (0.67 X calculated "raw" beta + 0.33 X Market Beta of 1.0) do a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

### b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.[27]

The analysis showed the following:

**Table A - 3**

| Returns Measured Over: | Coefficient on Beta | $R^2$ |
|---|---|---|
| 1956-2003 | -.088 | 47% |
| 1956-1997 | -.082 | 44% |
| 1964-1973 | -.020 | 1% |
| 1974-1983 | -.008 | 1% |
| 1984-1993 | -.056 | 11% |
| 1994-2003 | -.053 | 9% |

Source: Schedule 13, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as

[27] Non-overlapping periods were used so that each observation represents an independent time period. The length of the period was chosen to minimize the potential for random noise in the return data.

indicated in Table A-3 above, for the period 1956-2003, the $R^2$ of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2011, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,[28] and (c) the 10-year period ending 2011.

That analysis showed the following:

**Table A - 4**

| Returns Measured Over: | Coefficient on Beta | $R^2$ |
|---|---|---|
| 1988-2011 | -.063 | 52% |
| 1988-1997 | -.017 | 1% |
| 2002-2011 | -.094 | 18% |

Source: Schedule 13, page 2 of 2.

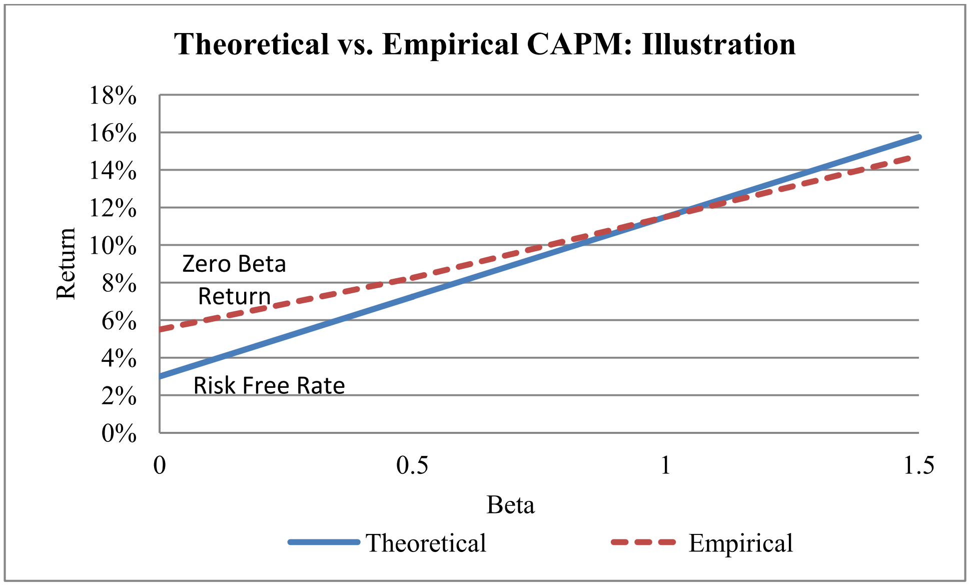
These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship (lower beta = lower return).[29]

The theoretical CAPM posits a market security line with an intercept equal to a "risk-free rate" and returns for risky securities proportional to their beta. Empirical studies point to a

[28] The use of this sub-period was intended to eliminate the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.
[29] In a 2011 article entitled "Benchmarks as Limits to Arbitrage: Understanding the Low-Volatility Anomaly", *Financial Analysts' Journal*, Vol. 67, No. 1, 2011, Drs. Malcolm Baker, Brendan Bradley and Jeffrey Wurgler conclude: "In an efficient market, investors realize above average returns only by taking above-average risks. Risky stocks have high returns, on average, and safe stocks do not. This simple empirical proposition has been hard to support on the basis of the history of U.S. stock returns. The most widely used measures of risk point rather strongly in the wrong direction."

higher intercept and a flatter market security line than the theoretical model posits. In other words, a "zero beta" stock has a higher return than the risk-free rate and low (high) beta stocks have achieved higher returns than their "raw" betas imply, as illustrated in Chart A-3 below.

**Chart A - 3**




The empirical studies that have tested the CAPM typically rely on a short-term government bond return. To some extent, the application of the CAPM using a long-term government bond yield rather than a short-term instrument adjusts for the tendency of the CAPM to understate (overstate) returns for low (high) beta stocks. The use of a long-term risk-free rate rather than a short-term rate shifts the intercept of the market security line upward and decreases the slope of the line. The implication of this shift for a stock with a "raw" beta of 1.0 can be illustrated as follows:

In Canada, the spread between the three-month Treasury bill and the long-term government bond yield historically has been approximately 130 basis points. If the three-month Treasury bill rate is 3.75%, the market return is 11.5% and the "raw" beta of a utility portfolio is 0.50, using the short-term rate as the risk-free rate produces a CAPM return of

7.625% (3.75% + 0.50 (11.5%-3.75%)). When a long-term Government of Canada bond yield of 5.0% is used as the risk-free rate, the CAPM return is equal to 8.25% (5.0% + 0.50 (11.5%-5.0%)). Replacing the short-term Treasury bill rate with the long-term government bond yield adjusts the cost of equity of a stock with a 0.50 "raw" beta upward by 0.625 percentage points. Similarly, using the long-term government bond yield as the risk-free rate adjusts the cost of equity of a stock with a "raw" beta of 1.50 downward by 0.625 percentage points.

The indicated increase in returns for low beta stocks that is indicated by the replacement of the short-term rate with the long-term rate is well below the 2.8 percentage point difference between the actual and predicted return for the lowest beta portfolio that was identified in the Fama and French study referenced above.

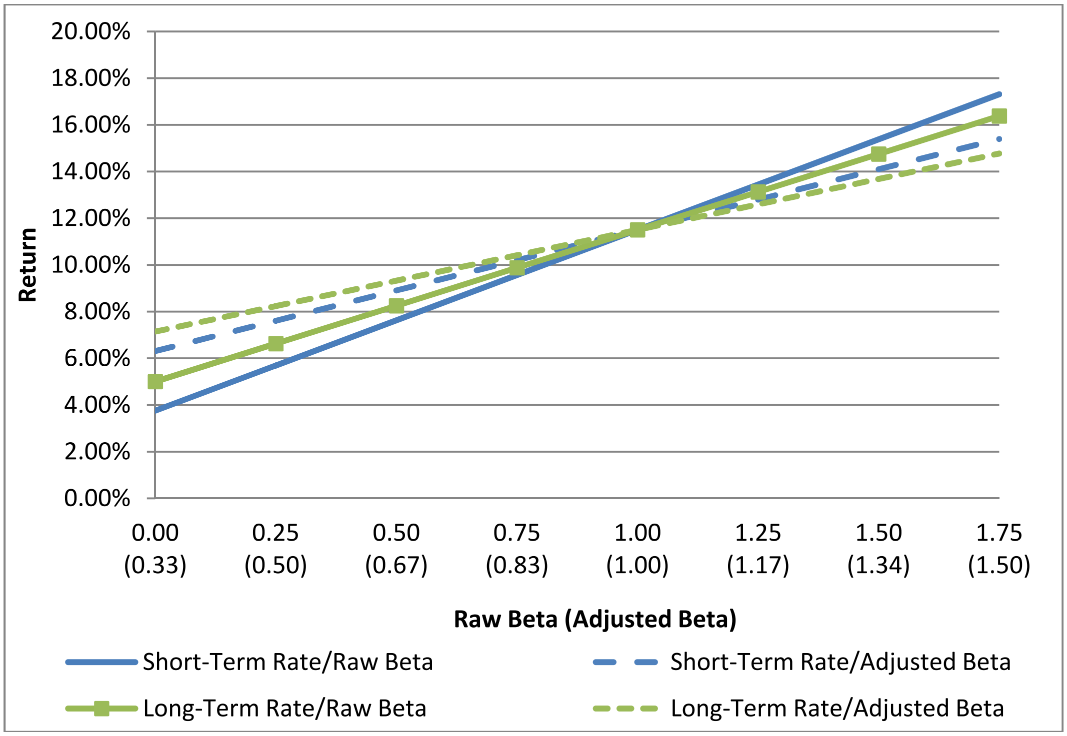
The use of adjusted betas in place of "raw" betas provides a further means of correcting for betas' under (over) prediction of returns for low (high) beta stocks. Reliance on adjusted betas initially arose in response to the empirically documented failure of betas calculated from one period to be good predictors of betas calculated in a subsequent period. The standard adjustment formula for beta adjusts the "raw" beta toward the market mean beta of 1.0 as follows:

Adjusted beta = "Raw Beta" X (2/3) + Market Mean Beta of 1.0 X (1/3)

While the standard beta adjustment formula was initially adopted to account for the observed tendency of betas generally to trend toward the market mean beta of 1.0, effectively its application acts to further adjust for the under and over prediction of returns of low and high beta stocks by the "classic" single variable CAPM. Reliance on betas adjusted using the formula set out above in conjunction with a long-term Government of Canada bond yield as the risk-free rate results in (1) a market security line intercept that lies above the long-term government bond yield and (2) a further flattening of the slope of the line. The implications are higher predicted returns for stocks with betas below the market mean beta of 1.0 and lower predicted returns for stocks with betas above the market mean beta of 1.0.

Chart A-4 below illustrates the differences in predicted returns arising from using (1) a short-term risk-free rate and a "raw" beta; (2) a short-term risk-free rate and an adjusted beta; (3) a long-term risk-free rate and a "raw" beta; and (4) a long-term risk-free rate and an adjusted beta. The key implications of using a long-term risk-free rate and an adjusted beta are: (1) a "zero beta" stock, i.e., one whose stock price movements are uncorrelated with those of the market portfolio would be expected to achieve a higher return than achievable by investing in government bonds; and (2) the trade-off between risk and return across the beta risk spectrum is less pronounced than suggested by either the short-term risk-free rate/"raw" beta or the long-term risk-free rate/"raw" beta approach.

**Chart A - 4**




Using the standard beta adjustment formula set out above moves a "raw" utility beta of 0.50 to 0.67. With the same inputs for market return (11.5%) and long-term government bond yield (5.0%) as in the previous example, the use of an adjusted beta rather than a "raw" beta increases the indicated utility equity return by close to 1.1%. The total adjustment to the utility equity return of approximately 1.7% (0.625% for the difference between the long-term and short-term risk-free rates and 1.1% for the difference between the adjusted and "raw" betas) is materially lower than the total 2.8 percentage point under-prediction for the lowest beta portfolio identified in the Fama and French study.

## APPENDIX B

# SELECTION OF U.S. LOW RISK UTILITY SAMPLE

For the estimation of a fair ROE for the benchmark BC utility using the Discounted Cash Flow-Based Equity Risk Premium Test and the Discounted Cash Flow Test, a sample of low risk U.S. utilities was selected.

The sample is comprised of all U.S. electric and natural gas utilities satisfying the following criteria:

1. Classified as either an electric or gas utility in *Value Line;*
2. Debt ratings of BBB+ or better and Baa1 or better by S&P and Moody's, respectively;
3. *Value Line* Safety Rank of 2 or better;
4. S&P Business Profile score of Excellent;
5. Regulated assets equal to or greater than 80% of total assets;
6. Consistent dividend history over the period 2002-2011;
7. Not being acquired or part of a merger; and
8. Long-term earnings growth forecasts available from three of four sources: Bloomberg, Reuters, *Value Line* and Zacks.

The twelve utilities that met these criteria are:

| | |
|---|---|
| AGL Resources | Piedmont Natural Gas |
| Alliant Energy | Southern Co. |
| Atmos Energy | Vectren Corp. |
| Consolidated Edison | WGL Holdings Inc. |
| Integrys Energy | Wisconsin Energy |
| Northwest Natural Gas | Xcel Energy Inc. |

Utility-specific information is found on pages B-2 to B-32 of this Appendix and on Schedule 15.

## AGL Resources

| Operating Characteristics: | |
|---|---|
| **Operations:** | Completed merger with NICOR in December 2011. Nation's largest natural gas-only distribution company (4.5 million customers)<br>Atlanta Gas Light - Georgia<br>Chattanooga Gas - Tennessee<br>Elizabethtown Gas - New Jersey<br>Elkton Gas - Maryland<br>Florida City Gas - Florida<br>NICOR Gas - Illinois<br>Virginia Natural Gas - Virginia<br>Other non-regulated businesses include competitive gas operations including retail services, wholesale operations, and shipping. |
| **Total Assets:** | $12,015 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 81% |
| **State(s) of Operation:** | Florida, Georgia, Illinois, Maryland, New Jersey, Tennessee and Virginia |
| **Number of Customers:** | Utility Customers:<br>IL 2.2 million<br>GA, FL & TN 1.7 million<br>MD, NJ & VA 0.6 million |
| **Customers by Type:** | **2010 Operating Revenues**<br>Residential 45.6%<br>Commercial 22.0%<br>Transportation 17.0%<br>Industrial 8.6%<br>Other 6.7% |
| **Regulatory Environment:** | |
| **Test Year:** | Partially Forecast - FL<br>Forecast - GA, IL, TN<br>Historic (adj. for known & measurable changes) - MD, NJ, VA |

(GAS cont'd)

| | |
|---|---|
| **Return on Equity (Latest Allowed):** | Atlanta Gas Light - 10.75% (2010, GA)<br>Chattanooga Gas - 10.05% (2010, TN)<br>Elizabethtown Gas - 10.3% (2009, NJ)<br>Elkton Gas- 8.33% overall return, settlement (2008, MD)<br>Florida City Gas -11.25% (2004, FL)<br>Nicor Gas - 10.17% (2009, IL)<br>Virginia Natural Gas - 10.0% (2011, VA) |
| **Equity Ratio (Latest Allowed):** | Atlanta Gas Light - 51.0% (2010)<br>Chattanooga Gas - 46.06% (2010)<br>Elizabethtown Gas - 47.89% (2009)<br>Florida City Gas -36.77% (2004)<br>Nicor Gas - 51.07% (2009)<br>Virginia Natural Gas - 45.36% (2011) |
| **Earnings Sharing:** | NJ - Elizabethtown Gas shares 50/50 up to $1m annually between monthly benchmark and the actual cost of gas<br>TN - Has interruptible margin credit rider where it shares equally with ratepayers margins resulting from transactions with non-regulated customers that utilize Chattanooga assets. |
| **Deferral Mechanisms:**[i] | Bad Debt Cost Recovery Mechanism - IL<br>Infrastructure Cost Recovery Mechanism - GA, NJ<br>Retirement benefit costs |
| **Fuel/Gas Cost Recovery:** | PGA - all states |
| **Sales and Weather Normalization:** | Revenue Decoupling - NJ (pending), TN<br>Flat Monthly Fee Rate Design (SFV) - GA, IL<br>Weather Normalization Adj - NJ, TN, VA |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (VA)<br>Average 1 (FL, GA, TN)<br>Average 3 (NJ)<br>Below Average 2 (IL and MD) |

(GAS cont'd)

| | |
|---|---|
| **Moody's Rating Methodology:**[iii] Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): Baa<br>Diversification (10%): Baa/A<br>Financial Strength (40%): Baa |
| **S&P's Regulatory Comment** | "generally regard Illinois to be a challenging regulatory environment for utilities to manage. However, Nicor has historically enjoyed satisfactory regulatory relations due in large part to its competitive rates to customers and good operating efficiency statistics. The utility has an acceptable 10.2% authorized return on equity, favorable weather-normalization and cost-recovery mechanisms, and a bad debt tracker. We view regulation in Georgia more favorably. In Georgia, the company benefits from a straight-fixed-variable-rate design structure that minimizes revenue risk due to weather and conservation. Georgia is one of a few states where natural gas delivery is deregulated." |

## Alliant Energy Corp.

| Operating Characteristics: | |
|---|---|
| **Operations:** | Principal subsidiaries are regulated utilities:<br>*Interstate Power and Light (IPL)*: electric generation and distribution, and gas distribution in Iowa and Minnesota; 2010 revenues 82% electric, 15% gas<br>*Wisconsin Power and Light (WPL)*: electric generation and distribution, and gas distribution in Wisconsin; 2010 revenues 85% electric, 14% gas<br><br>IPL sold electric transmission assets in IA, MN and IL to ITC Holdings in 2007; WPL transferred transmission assets to American Transmission Company in 2001 in exchange for ownership interest (16%) in ATC.<br><br>IPL and WPL members in MISO, a FERC-approved regional transmission organization (RTO).<br><br>Unregulated subsidiaries represent 5% of assets; include RMT (environmental, consulting, engineering and renewable energy services), rail and barge transportation services, and non-regulated generation. |
| **Total Assets:** | $9,283 million (2010) |
| **Percentage of Assets in Regulated Operations:** | Approximately 95% |
| **State(s) of Operations:** | Iowa, southern Minnesota, and southern and central Wisconsin |
| **Number of Customers:** | IPL – 526,000 electric customers and 234,000 gas customers in Iowa and southern Minnesota<br>WPL – 455,000 electric and 179,000 gas customers in Wisconsin |
| **Customers by Type:** | see below |

| Customer Type | 2010 % of Revenues | 2010% Sales (MWh) |
|---|---|---|
| Residential | 37% | 26% |
| Commercial | 23% | 21% |
| Industrial | 29% | 37% |
| Wholesale | 7% | 11% |
| Bulk Power & Other | 4% | 5% |

(LNT cont'd)

| Regulatory Environment: | |
|---|---|
| **Test Year:** | Historical in Iowa<br>Partial forecast for Minnesota<br>Forecast for Wisconsin |
| **Return on Equity (Latest Allowed):** | **Electric:**<br>IPL (Iowa): 10.44% blended ROE, including 10% on preponderance of rate base and 11.7% and 12.33% on specific generation investments (January 2011)<br>IPL (Minnesota): 10.35% (Aug 2011)<br>WPL (Wisconsin): 10.40% (Dec 2009)<br>**Gas:**<br>IPL (Iowa): 10.40% (Oct 2005)<br>WPL (Wisconsin): 10.40% (Dec 2009) |
| **Equity Ratio (Latest Allowed):** | **Electric:**<br>IPL (Iowa): 44.24% (Dec 2010)<br>IPL (Minnesota): 47.74% (Aug 2011<br>WPL (Wisconsin): 50.38% (Dec 2009)<br>**Gas:**<br>IPL (Iowa): 49.35% (Oct 2005)<br>WPL (Wisconsin): 50.38% (Dec 2009) |
| **Earnings Sharing:** | n/a |
| **Deferral Mechanisms:**[i] | Pension and OPEB, Energy Efficiency Cost Recovery (EECR), IPL was authorized (12/10) to implement a pilot transmission cost recovery mechanism (automatic rider) for a three-year term. The rider was implemented in conjunction with a 3-year base rate freeze and reduction in allowed ROE of 0.40%. |
| **Fuel/Gas Cost Recovery:** | IA: retail electric and gas tariffs contain automatic adjustment clause modified monthly.<br>WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause. |
| **Sales and Weather Normalization:** | Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers. |

(LNT cont'd)

| | |
|---|---|
| **RRA Regulatory Climate:**[ii] | Above Average 2 (WI)<br>Above Average 3 (IA)<br>Average 2 (MN) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): A<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): Baa<br>Financial Strength (40%): A |
| **S&P's Regulatory Comment** | "More credit supportive regulatory jurisdictions" |

## Atmos Energy

| **Operating Characteristics:** | |
|---|---|
| **Operations:** | *Natural gas distribution* – six divisions as follows:<br>Atmos Energy Colorado-Kansas<br>Atmos Energy Kentucky/Mid-States<br>Atmos Energy Louisiana<br>Atmos Energy Mid-Tex (includes Dallas and environs)<br>Atmos Energy Mississippi<br>Atmos Energy West Texas<br><br>Non-regulated businesses comprised of natural gas management and marketing services to municipalities, other LDCs and industrial customers, and natural gas transportation along with storage service to the own distribution divisions and third parties. |
| **Total Assets:** | $8,717 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 93% |
| **State(s) of Operation:** | Primary service areas are in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. More limited service in Georgia, Illinois, Iowa, Missouri and Virginia. Sale of Illinois, Iowa and Missouri assets announced in May 2011 (84,000 customers). |
| **Number of Customers:** | 3 million customers in 12 states |
| **Customers by Type:** | **2011 % Operating Revenues**<br>Residential 62.0% Public Authority 2.7%<br>Commercial 27.6% Transportation Revenues 2.4%<br>Industrial 4.2% Other Revenue 1.1% |
| **Regulatory Environment:** | |
| **Test Year:** | **Historic** - CO, LA<br>**Historic (adj. for known and measurable changes)** - IA, KS, KY, MO, TX and VA<br>**Partial Forecast** - GA<br>**Forecast** - IL, MS, TN |

ATO (cont'd)

| | | | |
|---|---|---|---|
| | | **Jurisdiction & Effective Date** | **ROE** |
| **Return on Equity (Latest Allowed):** | **Colorado-Kansas** | Colorado 01/04/2010 | 10.25% |
| | | Kansas 08/01/2010 | n/a |
| | **Kentucky/Mid-States** | Georgia 03/31/2010 | 10.70% |
| | | Illinois 11/01/2000 | 11.56% |
| | | Iowa 03/01/2001 | 11.00% |
| | | Kentucky 06/01/2010 | n/a |
| | | Missouri 09/01/2010 | n/a |
| | | Tennessee 04/01/2009 | 10.30% |
| | | Virginia 11/23/2009 | 9.50% -10.50% |
| | **Louisiana** | Trans LA 04/01/2011 | 10.00% -10.80% |
| | | LGS 07/01/2011 | 10.40% |
| | **Mid-Tex Settled Cities** | Texas 09/01/2011 | 9.70% |
| | **Mid-Tex Dallas** | Texas 06/22/2011 | 10.10% |
| | **Mid-Tex Environs GRIP** | Texas 06/27/2011 | 10.40% |
| | **Mississippi** | Mississippi 04/05/2011 | 9.86% |
| | **West Texas** | Amarillo 08/01/2011 | 9.60% |
| | | Lubbock 09/09/2011 | 9.60% |
| | | West Texas 08/01/2011 | 9.60% |
| | [1/] GRIP - Gas Reliability Infrastructure Program | | |
| **Equity Ratio (Latest Allowed):** | **Colorado-Kansas** | Colorado | 50% |
| | | Kansas | na |
| | **Kentucky/Mid-States** | Georgia | 48% |
| | | Illinois | 33% |
| | | Iowa | 43% |
| | | Kentucky | na |
| | | Missouri | 51% |
| | | Tennessee | 48% |
| | | Virginia | 49% |
| | **Louisiana** | Trans LA | 48% |
| | | LGS | 48% |
| | **Mid-Tex Settled Cities** | Texas | 50% |
| | **Mid-Tex Dallas & Environs** | Texas | 49% |
| | **Mississippi** | Mississippi | 50% |
| | **West Texas** | Amarillo | 48% |
| | | Lubbock | 48% |
| | | West Texas | 48% |

(ATO cont'd)

| | |
|---|---|
| **Earnings Sharing:** | Performance based rate programs in Georgia (if earnings outside range of 10.5%-10.9% then rates adjusted to change revenue to achieve the upper/lower earnings band; no rate change if earnings within the band), Kentucky and Tennessee whereby purchased gas costs savings are shared. |
| **Deferral Mechanisms:**[i] | Bad debt rider in CO, KS, KY, TN, TX and VA<br>Infrastructure Cost Recovery in GA, KS, KY, MO and TX<br>OPEB Cost Recovery in LA and MS |
| **Fuel/Gas Cost Recovery:** | All states |
| **Sales and Weather Normalization:** | Weather Normalization Adjustments approved for "94% of residential and commercial margins" in company's service areas (GA, KS, KY, LA, MS and TX)<br>Innovative rate structures approved:<br>MO: flat fee rate plus small variable charge: 75% costs recovered in monthly fee<br>LA, MS & TX: Rate stabilization tariffs<br>GA: Georgia Rate Adjustment Mechanism (GRAM) providing a non-gas cost revenue true-up implemented 12/2011. |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (VA)<br>Above Average 3 (IA and MS)<br>Average 1 (CO, GA, KY, LA, TN)<br>Average 2 (KS and MO)<br>Below Average 1 (TX)<br>Below Average 2 (IL) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): Baa<br>Diversification (10%): A<br>Financial Strength (40%): A |
| **S&P's Regulatory Comment** | "geographic and regulatory diversity in regulatory operations"; "favorable regulatory oversight" |

## Consolidated Edison Inc

| **Operating Characteristics:** | |
|---|---|
| **Operations:** | Principal subsidiaries are regulated transmission and distribution utilities comprising largest utility system in New York State area:<br>*Con Edison of New York*: electric, gas and steam distribution and transmission infrastructure<br>*Orange & Rockland*: gas and electric distribution infrastructure. ORU in turn has two wholly owned electric subsidiaries - Rockland Electric (NJ) and Pike County Light & Power (PA)<br>Unregulated subsidiaries represent less than 5% of assets; include retail and wholesale energy supply. |
| **Total Assets:** | $35,600 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 98% |
| **State(s) of Operation:** | New York including most of New York City; northern New Jersey and parts of eastern Pennsylvania |
| **Number of Customers:** | ConEd NY - 3.3 million electric customers, 1.1 million gas customers (New York City and Westchester County) and 23,000 steam customers<br>Orange & Rockland – 0.3 million electric customers in NY, NJ and PA and over 0.1 million gas customers in southeastern NY and northeastern PA. |
| **Customers by Type:** | **2010 % Revenues**<br>**Customer Type** / **Electric** / **Gas**<br>Residential: 37% / 47%<br>Com./Industrial: 31% /<br>Retail Access: 25% /<br>General: / 21%<br>Trans. & Other: / 32% |
| **Regulatory Environment:** | |
| **Test Year:** | Forecast |
| **Return on Equity (Latest Allowed):** | **Electric:** ConEd NY: 3/10 - 10.15% 3 yr settlement (previously 10%, 2009)<br>Orange & Rockland: 6/11 - 9.2% (fully litigated)<br>Rockland Electric (NJ): 6/10 - settlement 10.3% (previously 9.75%, 2007)<br>**Gas:** ConEd NY: 9/10 - 9.6%; (prev. 9.7% 3 yr plan)<br>Orange & Rockland: 10/09 adopted 10.4%- 3 yr plan expiring Oct. 2012 |

(ED cont'd)

| | |
|---|---|
| **Equity Ratio (Latest Allowed):** | ConEd NY: 48.0% (2010)<br>Orange & Rockland: 48.0% (2011)<br>Rockland Electric: 49.85% (2010) |
| **Earnings Sharing:** | *ConEd*<br>Electric: 100bp over allowed ROE shared 50/50<br>Gas: 75bp over allowed ROE shared 60/40 (ratepayers/shareholders)<br>*Orange & Rockland*<br>Electric: Earnings between 10.2% & 11.2% ROE shared 50/50; above 11.2% shared 75/25 (ratepayers/shareholders)<br>Gas: Earnings between 11.4% and 12.4% shared 50/50; 12.4% to 14% shared 65/35 (ratepayers/shareholders); over 14% allocated 90% to ratepayers. ROE threshold reduced 20 basis points in any rate year company fails to meet objectives of its retail choice program |
| **Deferral Mechanisms:** [i] | Deferral of certain expenses: property taxes (partial), interest on debt (partial), pension and OPEB, environmental remediation expenses, deferred derivative losses (long-term) gas rate plan deferral, World Trade restoration costs collected through rates/riders; bad debt recovery mechanism (NY) and relocation of facilities to accommodate government projects. |
| **Fuel/Gas Cost Recovery:** | With electric industry restructuring, transitioned from the fuel adjustment clause (FAC) to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill (i.e., monthly, bi-monthly, etc.). Although the incumbent distributors retain the provider-of-last-resort (POLR) obligation, the operation of these clauses leaves the distributor insulated from any financial effects associated with changes in market prices. Recovery of gas commodity costs is through semi-automatic fuel adjustment clauses. |

(ED cont'd)

| | |
|---|---|
| **Sales and Weather Normalization:** | Revenue decoupling for both gas and electric; weather normalization adjustment clauses for gas companies |
| **RRA Regulatory Climate:**[ii] | Average 3 (NJ, NY and PA) |
| **Moody's Rating Methodology:**[iii] Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): Baa<br>Diversification (10%): A<br>Financial Strength (40%): Baa |
| **S&P's Regulatory Comment** | "Con Edison's subsidiaries have endeavored to reach constructive multiyear settlements in their rate case filings, reducing the need for regular rate filings and ensuring cash flow stability." |

## Integrys

| | |
|---|---|
| **Operating Characteristics:** | |
| **Operations:** | **Regulated Subsidiaries**:<br>*Wisconsin Public Service Corp (WPS)*<br>*Peoples Gas Light & Coke Co. (PG)*<br>*North Shore Gas Co. (NSG)*<br>*Upper Peninsula Power Co.(UPP)*<br>*Minnesota Energy Resources Corp.(MERC)*<br>*Michigan Gas Utilities Corp (MGU)*<br>**Regulated Investments:**<br>34% interest in *American Transmission Co.(ATC)*<br>**Non-rate-regulated:**<br>*Integrys Energy Services* |
| **Total Assets:** | $9,400 million. |
| **Percentage of Assets in Regulated Operations:** | Approximately 87% |
| **State(s) of Operation:** | Illinois (ATC, PG, NSG), Michigan (ATC, MGU, MERC, UPP), Minnesota (ATC) and Wisconsin (WPS, ATC), |
| **Number of Customers:** | Integrys Energy - 1.7 million natural gas and 0.5 million electric customers |

| Customers | '000s | % | Gas | Electric |
|---|---|---|---|---|
| Wisconsin Public Serv. | 757 | 35% | 19% | 89% |
| Peoples Gas | 819 | 23% | 49% | - |
| Minnesota Energy Res. | 212 | 6% | 13% | - |
| Michigan Gas Utilities | 166 | 2% | 10% | - |
| North Shore Gas | 158 | 8% | 9% | - |
| Upper Peninsula Power | 52 | 7% | - | 11% |

**Customers by Type:**

| Gas Throughput (therms) | | Electric Sales (kWh) | |
|---|---|---|---|
| Residential | 40.1% | Residential | 19% |
| Comm. & Industrial | 12.2% | Comm. & Indus. | 51% |
| Interruptible | 1.1% | Wholesale | 30% |
| Transport | 46.3% | Other | <1% |

| | |
|---|---|
| **Regulatory Environment:** | |
| **Test Year:** | Forecast- Illinois, Wisconsin<br>Partial forecast - Michigan, Minnesota |

(TEG cont'd)

| | |
|---|---|
| **Return on Equity (Latest Allowed):** | **Gas Decisions:**<br>WPS: 10.3% (Jan 2011)<br>PG, NSG: 10.45% (Jan 2012);<br>MERC: 10.21% (June 2009)<br>MGU: 10.75% (Dec 2009)<br>**Electric Decisions:**<br>WPS: 10.3% (Jan 2011)<br>UPP: 10.2% (Dec 2011) |
| **Equity Ratio (Latest Allowed):** | **Gas Decisions:**<br>WPS: 51.65% (Jan 2011)<br>PG, NSG: 49% and 50.0%, respectively (Jan 2012)<br>MERC: 48.77% (June 2009)<br>MGU: 46.49% (Dec 2009)<br>**Electric Decisions:**<br>WPS: 51.65% (Jan 2011)<br>UPP: 45.74% (Dec 2011) |
| **Earnings Sharing:** | n/a |
| **Deferral Mechanisms:**[i] | **MI:** uncollectible expense true-up mechanism for MGU.<br>**MN:** n/a<br>**IL:** *Gas* - bad debt riders; infrastructure cost recovery<br>**WI:** pension and other post retirement benefit costs related to 2008 losses (approved 2009) |
| **Fuel/Gas Cost Recovery:** | **WI:** purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.<br>**MN:** fuel adjustment clause that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator costs.<br>**MI**: The Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) clauses require utilities to annually file projected costs, and a forward-looking PSCR or GCR supply factor is established at the beginning of the 12 month collection period. Annual reconciliation proceedings are required.<br>**IL:** *Electric* - The power to meet the utilities' standard offer service (SOS) obligations is procured competitively; SOS costs and revenues are subject to an annual true-up mechanism.<br>*Gas* - PGA clause |

(TEG cont'd)

| | |
|---|---|
| **Sales and Weather Normalization:** | **Decoupling:**<br>**WI -** WPS' decoupling mechanism includes an annual cap for the deferral of any excess or shortfall from the rate case authorized margin ($8m gas; $14m electric)<br>**MI -** UPP's decoupling mechanism terminated effective 1/2012 by settlement- new mechanism to commence 1/2013<br>**IL -** 1/2012 decision made permanent for both NSG & PG a decoupling mechanism (Volume Balancing Rider (VBA)) first approved in 2008; also established rate design permitting 67% (NSG) and 55% (PG) of fixed costs to be recovered in customer charges<br>**MN -** n/a |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (WI)<br>Average 1 (MI)<br>Average 2 (MN)<br>Below Average 2 (IL) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): Baa<br>Diversification (10%): A/Baa<br>Financial Strength (40%): A |
| **S&P's Regulatory Comment** | "Integrys has continued to effectively manage its regulatory risk--including its recent rate case orders for PG and NSG that will collectively raise rates by almost $60 million--which we view as credit supportive. We expect that the company will continue to effectively manage its regulatory risk over the medium term with the goal of further reducing its regulatory lag." |

## Northwest Natural Gas Co.

| | |
|---|---|
| **Operating Characteristics:** | |
| **Operations:** | *Utility* – local regulated gas distribution business<br>*Gas Storage* – storage services to intrastate and interstate customers and asset optimization services<br>*Other* – investments in gas pipelines (1% of assets) |
| **Total Assets:** | $2,600 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 99% |
| **State(s) of Operation:** | 90 communities in Oregon and southwest Washington, including Portland and Eugene OR, and Vancouver WA. |
| **Number of Customers:** | 674,000 customers (90% customer base in Oregon) |
| **Customers by Type:** | **Customer Type** — **2010 % of Revenues**<br>Residential — 61%<br>Commercial — 30%<br>Industrial — 9% |
| **Regulatory Environment:** | |
| **Test Year:** | Partial or full forecast for Oregon<br>Historic with adjustments for known and measurable changes for Washington |
| **Return on Equity (Latest Allowed):** | 10.2% (2003 OR)<br>10.1% (2008 WA) |
| **Equity Ratio (Latest Allowed):** | 49.50% (2003 OR)<br>50.74% (2008 WA) |
| **Earnings Sharing:** | Tied to PGA option; see Fuel/Gas Cost Recovery |
| **Deferral Mechanisms:**[i] | Pipeline integrity management program<br>Pension expense and OPEB deferral<br>Environmental cost deferral<br>Infrastructure cost recovery mechanism |
| **Fuel/Gas Cost Recovery:** | PGA in Oregon – contains an incentive mechanism whereby a percentage of various between companies' cost of gas in rates and actual cost is absorbed or retained by the LDC - subject to annual earnings review<br>PGA in Washington requires 100% pass through of prudently incurred gas cost deferrals |
| **Sales and Weather Normalization:** | Revenue decoupling in Oregon; Weather normalization adjustment in Oregon (through 2012). |

(NWN cont'd)

| | |
|---|---|
| **RRA Regulatory Climate:**[ii] | Average 3 (OR and WA) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): A<br>Financial Strength (40%): Baa |
| **S&P's Regulatory Comment** | "..supportive rate design and incentive programs that allow exceptionally stable cash flows that are largely insulated from gas price, weather, and usage rate fluctuations." |

## Piedmont Natural Gas

| | |
|---|---|
| **Operating Characteristics:** | |
| **Operations:** | *Regulated* – distribution of natural gas<br>*Unregulated* – retail natural gas marketing, storage and transportation |
| **Total Assets:** | $3,050 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 97% |
| **State(s) of Operation:** | North Carolina (72% net utility plant), South Carolina, Tennessee |
| **Number of Customers:** | 968,188 customers |
| **Customers by Type:** | **Customer Type** — **2011 % of Revenues**<br>Residential 56%<br>Commercial 32%<br>Industrial 9% |
| **Regulatory Environment:** | |
| **Test Year:** | Historic test period in NC and SC (adjusted for known and measurable changes)<br>Forward test year in TN |
| **Return on Equity (Latest Allowed):** | 10.6% (2008 NC)<br>11.3% (2011 SC)<br>10.2% (2011 TN, stipulation) |
| **Equity Ratio (Latest Allowed):** | 51% (2008 NC)<br>61% (2011 SC)<br>52.71% (2011 TN, stipulation) |
| **Earnings Sharing:** | Rate stabilization tariffs in SC: revenues adjusted annually such that earned ROE remains within a range of +/- 50 basis points of the allowed ROE of 11.3%. |
| **Deferral Mechanisms:**[i] | Pension and retirement benefits expense<br>Environmental remediation<br>Demand side management<br>Pipeline integrity expense<br>Bad debt cost recovery mechanism (NC, SC & TN) |
| **Fuel/Gas Cost Recovery:** | PGA recovers 100% of costs |

(PNY cont'd)

| | |
|---|---|
| **Sales and Weather Normalization:** | Decoupling tariffs in NC only. In NC the Customer Utilization Tracker (CUT) is in effect, accounting for the impact of both weather and utilization.<br>Weather normalization in all other areas. |
| **RRA Regulatory Climate:**[ii] | Above Average 3 (NC)<br>Average 1 (SC and TN) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): A<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): A<br>Financial Strength (40%): A |
| **S&P's Regulatory Comment** | "Supportive regulatory environment" |

## Southern Co.

| Operating Characteristics: | |
|---|---|
| **Operations:** | **Traditional Operating Companies:**<br>Each own generation, transmission and distribution facilities:<br>*Alabama Power* (Alabama)<br>*Georgia Power* (Georgia)<br>*Gulf Power* (Florida)<br>*Mississippi Power* (Mississippi).<br>**Southern Power:**<br>Public utility which constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates. Subject to FERC regulation.<br>**Non-Utility Operations:**<br>Digital wireless communications, operates and provides services to utilities' nuclear plants, acquires, owns, and constructs renewable generation assets. |
| **Total Assets:** | $55,700 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 92% |
| **State(s) of Utility Operations:** | Majority of operations in Alabama and Georgia, along with the northwestern portion of Florida and southeastern Mississippi. |
| **Number of Customers:** | 4.4 million customers (traditional operating companies) |
| **Customers by Type:** | **Customer Type** / **2010 % of Operating Revenues**<br>Residential 38%<br>Commercial 31%<br>Industrial 19%<br>Other - Retail 1%<br>Wholesale 12% |
| **Regulatory Environment:** | |
| **Test Year:** | AL: Historic with adjustments for known and measurable changes<br>FL: Partial or full forecast<br>GA: Partial forecast<br>MS: Full forecast |

(SO cont'd)

| | |
|---|---|
| **Return on Equity (Latest Allowed):** | 13.75% (2005 AL)<br>10.25% (2012 FL)<br>11.15% (2010 GA)<br>10.701% (2011 MS) ROE is performance adjusted and reflects Alternative Rate Plan (ARP) filing |
| **Equity Ratio (Latest Allowed):** | 45.00% (2005 AL)<br>46.26% (2012 FL)<br>51.67% (2001 GA)<br>47.51% (2011 MS) based on ARP filing |
| **Earnings Sharing:** | **AL:** Alabama Power operates under a Rate Stabilization and Equalization framework. Annual rate increases limited to 5% and rate increases for any two-year period, when averaged, cannot exceed 4% per year. If projected ROE is outside the allowed ROE range of 13%-14.5% rates are adjusted, subject to the limits above, to establish a 13.75% ROE. If actual earned ROE is above 14.5%, customers are refunded revenues that caused the earned ROE to exceed 14.5%. No provision for recovering shortfalls if the earned ROE is below 13%.<br>**GA:** Georgia Power operating under an alternative rate plan since 1996; current version applies to years 2011-2013. Not permitted to file a general rate case unless earnings are projected to fall below a 10.25% ROE. Two-thirds of earnings above a 12.25% ROE are refunded to customers. No automatic recovery of any earnings shortfall below a 10.25% ROE, but may petition to utilize an Interim Cost Recovery Tariff to adjust earnings to a 10.25% ROE in lieu of filing a rate case. Permitted to retain 15% of the net present value of the net benefits generated by certain demand-side management programs. |
| **Deferral Mechanisms:**[i] | Pension and employee benefit expense, Environmental remediation costs, Storm damage cost recovery.<br>**AL:** Rate Certificated New Plant (CNP) mechanism adjusts rates annually to recognize the cost of placing new generating facilities in retail service and recovery of retail costs associated with certificated PPAs. CNP includes environmental costs and return on invested capital. Plant outage costs.<br>**GA**: CWIP in rate base; plant outage costs. |

(SO cont'd)

| | |
|---|---|
| **Fuel/Gas Cost Recovery:** | **AL:** Energy Cost Recovery (ECR) rate in place established on the basis of estimates of electric sales, fuel, and net purchased energy costs, and reflects accumulated over- or under-recovered amounts.<br>**GA:** non-automatic fuel adjustment mechanism is in place.<br>**FL:** the fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established base upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during with the PSC sets fuel factors for the next calendar year.<br>**MS**: an automatic electric fuel adjustment clause is in effect, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates. |
| **Sales and Weather Normalization:** | n/a |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (AL)<br>Above Average 3 (MS)<br>Average 1 (FL and GA) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): A<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): Baa<br>Financial Strength (40%): A/Baa |
| **S&P's Regulatory Comment** | "Operations under generally constructive regulatory environments" |

## Vectren Corp

| **Operating Characteristics:** | |
|---|---|
| **Operations:** | *Vectren Utility Holdings* – comprised of Indiana Gas, Southern Indiana Gas & Electric Company and Ohio operations.<br>*Vectren Enterprises* – support services to utility operations. |
| **Total Assets:** | $4,795 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 82% |
| **State(s) of Operation:** | Nearly 2/3rds of the state of Indiana (gas and electric) and part of Ohio (gas). |
| **Number of Customers:** | 681,000 gas and 142,000 electric customers in central and southern Indiana. 314,000 gas customers in west central Ohio. |
| **Customers by Type:** | **Customer Type** — **2010 % of Margin**<br>Residential & Comm. — 86%<br>Industrial — 12%<br>Other — 3% |
| **Regulatory Environment:** | |
| **Test Year:** | Historic with adjustments for known and measurable changes for Indiana<br>Partial forecast for Ohio |
| **Return on Equity (Latest Allowed):** | **Electric:**<br>SIGECO: 10.4% (2011)<br>Vectren Energy Delivery Ohio: 8.89% overall return (2009) settlement<br>**Gas:**<br>Indiana Gas: 10.20% (2008)<br>SIGECO: 10.15% (2007) |
| **Equity Ratio (Latest Allowed):** | SIGECO: 49.93% (2011)<br>Indiana Gas: 48.99% (2008 IN)<br>Vectren Energy Delivery: 48.10% (2005 OH); 2009 not specified |
| **Earnings Sharing:** | n/a |

(VVC cont'd)

| | |
|---|---|
| **Deferral Mechanisms:**[i] | Employee benefit deferral<br>Demand side management expense<br>Pipeline integrity expense<br>Bad debt recovery mechanism (IN, OH)<br>Environmental CWIP tracker<br>Infrastructure cost recovery (IN, OH) |
| **Fuel/Gas Cost Recovery:** | Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC) |
| **Sales and Weather Normalization:** | Decoupling (gas) in IN through weather normalization and conservation tariffs<br>Straight fixed variable rate design (OH) |
| **RRA Regulatory Climate:**[ii] | Above Average 3 (IN)<br>Average 2 (OH) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses<br>Note: Info for Vectren Utility Hldgs. | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): Baa<br>Financial Strength (40%):A |
| **S&P's Regulatory Comment** | "... supportive regulation and a lack of competition" |

## WGL Holdings Inc.

| | |
|---|---|
| **Operating Characteristics:** | |
| **Operations:** | *Regulated Utility* – Washington Gas (DC,MD & VA) and Hampshire (FERC)<br>*Retail Energy-Marketing* –sales of natural gas and electric commodity<br>*Design-Build energy systems*-energy efficiency solutions to government and commercial customers |
| **Total Assets:** | $3,930 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 87% |
| **State(s) of Operation:** | District of Columbia, Maryland and Virginia |
| **Number of Customers:** | 1.1 Million – 14% DC, 41% MD, 45% VA |
| **Customers by Type:** | **Customer Type** / **2009 % of Therms Delivered**<br>Residential: 77.3%<br>Commercial and Industrial: 22.7% |
| **Regulatory Environment:** | |
| **Test Year:** | Partial forecast for Maryland and Washington D.C. Historic with adjustments for known and measurable changes for Virginia |
| **Return on Equity (Latest Allowed):** | District of Columbia: 10.0% (2006)<br>Maryland: 9.6% (2011)<br>Virginia: 10.0% (2011) |
| **Equity Ratio (Latest Allowed):** | 50.30% (2003 DC); unspecified in 2006<br>57.88% (2011 MD)<br>55.70% (2011 VA) |
| **Earnings Sharing:** | n/a |
| **Deferral Mechanisms:**[i] | Trackers for pension and OPEB; accelerated recovery mechanisms for costs of eligible infrastructure replacement programs in VA |
| **Fuel/Gas Cost Recovery:** | PGAs recover 100% of costs. A Gas Administrative Charge (GAC) permits company to recover bad debts relating to gas costs through the purchased gas charge clause rather than base rates. |

(WGL cont'd)

| | |
|---|---|
| **Sales and Weather Normalization:** | Weather normalization (VA)<br>Decoupling (MD)<br>Declining block rates (MD, VA) |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (VA)<br>Average 2 (DC)<br>Below Average 2 (MD) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses<br>Note: Info for Washington Gas Light | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): A<br>Financial Strength (40%): A |
| **S&P's Regulatory Comment** | "excellent business risk profile reflects an affluent and stable service territory, supportive regulatory mechanisms, moderate regulatory and market diversification, and low operating risk. Supportive regulatory mechanisms enhance Washington Gas Light's cash flow stability, which further supports credit quality." |

## Wisconsin Energy Corp.

<table>
<tr><td colspan="2">Operating Characteristics:</td></tr>
<tr><td>Operations:</td><td>Utility Energy – electric and gas utilities operating together under the trade name of We Energies (Wisconsin Electric, Wisconsin Gas). Completed sale of Edison Sault in 2010.<br>Non-Utility Energy –We Power designs, constructs, owns, and leases generating capacity.</td></tr>
<tr><td>Total Assets:</td><td>$14,911million</td></tr>
<tr><td>Percentage of Assets in Regulated Operations:</td><td>Approximately 80%</td></tr>
<tr><td>State(s) of Operation:</td><td>Wisconsin and the Upper Peninsula of Michigan</td></tr>
<tr><td>Number of Customers:</td><td>1.1 million electric customers in Wisconsin & Michigan’s Upper Peninsula<br>1.0 million gas customers in Wisconsin<br>0.5 million steam customers in Milwaukee</td></tr>
<tr><td>Customers by Type:</td><td><table>
<tr><th></th><th colspan="2">2010% Revenues</th></tr>
<tr><th>Customer Type</th><th>Electric</th><th>Gas</th></tr>
<tr><td>Residential</td><td>38%</td><td>63%</td></tr>
<tr><td>Comm./Industrial</td><td>55%</td><td>31%</td></tr>
<tr><td>Other</td><td>7%</td><td>6%</td></tr>
</table></td></tr>
<tr><td colspan="2">Regulatory Environment:</td></tr>
<tr><td>Test Year:</td><td>MI: Partial forecast<br>WI: Forecast</td></tr>
<tr><td>Return on Equity (Latest Allowed):</td><td>Electric:<br>10.40% (2009 WI)<br>10.25% (2010 MI)<br>Gas:<br>10.40% (2009 WI)</td></tr>
<tr><td>Equity Ratio (Latest Allowed):</td><td>Electric:<br>53.02% (2009 WI)<br>52.48% (2010 MI)<br>Gas:<br>53.02% (2009 WI)</td></tr>
<tr><td>Earnings Sharing:</td><td>n/a</td></tr>
<tr><td>Deferral Mechanisms:[i]</td><td>Bad debt expense, recovery of unrecovered transmission costs, pension and OPEB</td></tr>
</table>

(WEC cont’d)

| | |
|---|---|
| **Fuel/Gas Cost Recovery:** | Gas: Full recovery. One-for-one recovery measured against a monthly benchmark with 2% tolerance. Costs above the benchmark subject to further review.<br>Fuel and Purchased Power: no automatic adjustments; no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis. |
| **Sales and Weather Normalization:** | n/a |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (WI)<br>Average 1 (MI) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): A<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): Baa<br>Financial Strength (40%): Baa |
| **S&P's Regulatory Comment** | "benefits from responsive regulation in Wisconsin, characterized by supportive cost-recovery ratemaking mechanisms" |

## Xcel Energy Inc.

| Operating Characteristics: | |
|---|---|
| **Operations:** | Regulated Utilities:<br>*Northern States Power Minnesota*: electric distribution in Minnesota, North Dakota, and South Dakota. Gas distribution in Minnesota and North Dakota<br>*Northern States Power Wisconsin*: electric and gas distribution in Wisconsin and Michigan<br>*Public Service Co. of Colorado*: electric and gas distribution in Colorado<br>*Southwestern Public Service*: electric distribution in Texas and New Mexico<br>WestGas InterState-a small interstate natural gas pipeline.<br>WYCO Development-50% ownership, develops and leases natural gas pipeline, storage, and compression facilities.<br><br>Unregulated subsidiaries-rental housing projects |
| **Total Assets:** | $30,000 million |
| **Percentage of Assets in Regulated Operations:** | Approximately 95% |
| **State(s) of Operation:** | Colorado, Michigan (western Upper Peninsula), Minnesota, New Mexico, North Dakota, South Dakota, Texas, northwestern Wisconsin and Texas |
| **Number of Customers:** | 3.4 million electric customers and 1.9 million gas customers. |
| **Customers by Type:** | see below |

| Electric | 2010 % of Revenues |
|---|---|
| Residential | 31% |
| Commercial and Industrial | 53% |
| Public Authorities & Other | 2% |
| Wholesale | 11% |
| Other | 3% |
| **Gas Customer Type** | |
| Residential | 63% |
| Commercial and Industrial | 33% |
| Transportation & Other | 4% |

(XEL cont'd)

| Regulatory Environment: | |
|---|---|
| **Test Year:** | CO, NM, SD, TX: Historic with adjustments for known and measurable changes<br>MN, MI: Partial forecast<br>ND: Partial or full forecast<br>WI: Full forecast |
| **Return on Equity (Latest Allowed):** | **Electric:**<br>10.0% (2012 CO)<br>10.37% (2012 MN)<br>10.40% (2012 ND)<br>10.18% (2008 NM)<br>8.32% (2010 SD) overall ROE, settlement<br>10.40% (2011 WI)<br>**Gas:**<br>10.10% (2011 CO)<br>10.09% (2010 MN)<br>10.75% (2007 ND)<br>10.40% (2011 WI) |
| **Equity Ratio (Latest Allowed):** | **Electric:**<br>56.0% (2012 CO)<br>52.56% (2012 MN)<br>51.77% (2008 ND)<br>51.23% (2008 NM)<br>52.59% (2011 WI)<br>**Gas:**<br>56.0% (2011 CO)<br>52.46% (2010 MN)<br>51.77% (2008 ND)<br>52.59% (2011 WI) |
| **Earnings Sharing:** | ND: earnings in excess of 10.75% ROE are shared with customers. If earnings are between 10.75%-11.25% ROE, they are shared equally. Earnings above 11.25% ROE are shared 75% to ratepayers and 25% to shareholders.<br>CO: customers receive bill credits if company did not achieve certain performance targets relating to electric reliability, customer service, and natural gas leak repair time. |

(XEL cont'd)

| | |
|---|---|
| **Deferral Mechanisms:**[i] | Pension and OPEB<br>CO, MN: Enhanced cost recovery for emissions reduction provides a return on CWIP and an incentive based ROE (energy savings goals)<br>CO: specific retail rate rider for certain costs associated with renewable energy resources; Transmission Cost Adjustment recovers costs associated with investments in transmission facilities<br>TX: recovery of certain transmission investments and other transmission costs through TCRF rider |
| **Fuel/Gas Cost Recovery:** | Cost-of-Energy Adjustment mechanisms for purchases of coal, nuclear fuel and natural gas in all states except Wisconsin: no automatic adjustments; no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis. |
| **Sales and Weather Normalization:** | n/a |
| **RRA Regulatory Climate:**[ii] | Above Average 2 (WI)<br>Average 1 (CO, MI, ND)<br>Average 2 (MN)<br>Average 3 (SD)<br>Below Average 1 (NM and TX) |
| **Moody's Rating Methodology:**[iii]<br>Weight accorded to category in parentheses | Regulatory Framework (25%): Baa<br>Ability to Recover Costs/Earn Return (25%): A<br>Diversification (10%): A<br>Financial Strength (40%): A/Baa |
| **S&P's Regulatory Comment** | "credit-supportive regulation" |

[i] Lost and Unaccounted for Gas Trackers (LUAF) are in 47 of 50 states (excluding Michigan, Montana and South Dakota) (AGA, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List As of March 2012)*

[ii] RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects RRA's assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

[iii] Financial strength is comprised 10% liquidity and four metrics each weighted 7.5% for a total of 40%. The four metrics measured are: i) (Cash from operations (CFO) pre-working capital (WC) plus interest) over interest expense; ii) CFO Pre-WC/Debt; iii) (CFO Pre-WC less dividends)/Debt; and iv) Debt/Book Capitalization.

APPENDIX C

# DISCOUNTED CASH FLOW TEST

## 1. CONCEPTUAL UNDERPINNINGS

The discounted cash flow (DCF) approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return, which is the rate that equates the price of the stock to the discounted value of future cash flows.

## 2. DCF MODELS

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. To estimate the DCF cost of equity, both constant growth and a three-stage growth models were utilized. These two models are discussed below.

### a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) \quad = \quad \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[30]

$\mathbf{P_o}$ = current price

$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

### b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

Using the three-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

[30] Alternatively expressed as $D_o$ (1 + g), where $D_o$ is the most recently paid dividend.

The cash flow per share in Year 1 is equal to:

**Last Paid Annualized Dividend x (1 + Stage 1 Growth)**

For Years 2 through 5, cash flow is defined as:

**Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)**

For Years 6 through 10, cash flow is defined as:

**Cash Flow $_{t-1}$ x (1 + Stage 2 Growth)**

Cash flows from Year 11 onward are estimated as:

**Cash Flow $_{t-1}$ x (1 + GDP Growth)**

## 3. GROWTH COMPONENT OF THE DCF MODELS

The growth component of the DCF models is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.) Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be.

**a. Constant Growth Model Growth Rates**

In the application of the constant growth model, two estimates of investors' expectations of long-term earnings growth were relied upon: a consensus of investment analysts' earnings forecasts and an estimate of the sustainable growth rate. The consensus earnings growth forecasts were obtained from four different sources, Bloomberg, Reuters, *Value Line* and Zacks. Bloomberg[31] and Reuters[32] are both global providers of real time financial news and data. *Value Line* provides investment research and forecasts for approximately 1,700 large capitalization stocks as well as investment research on 1,800 mid and small capitalization stocks. Its publications are broadly accessible to both individual and institutional investors. Zacks provides consensus estimates and ratings for approximately 4,500 US and Canadian companies that have at least one sell-side analyst covering them. In general, all of these long-term earnings forecasts refer to a period of between three and five years and are intended to represent the normalized ("smoothed") rate of earnings growth over a business cycle. The consensus earnings forecasts are reflective of the analyst community's views and, therefore, are a reasonable proxy of (unobservable) investor growth expectations.

As an alternative to the consensus of investment analysts' earnings forecasts, constant growth DCF costs of equity for the sample were estimated based on sustainable growth rates derived from *Value Line* forecasts of returns on equity, earnings retention rates and earnings growth from external financing.

Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and

[31] Bloomberg data are available for a fee on the internet and through "Bloomberg terminals". Bloomberg has offices in more than 200 places around the world.
[32] Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries. Reuters is part of Thomson Reuters, which also publishes I/B/E/S and First Call consensus earnings growth estimates.

dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (B) expected to be retained multiplied by expected return on equity (R). The external financing portion of the sustainable growth rate is estimated as the forecast growth in the number of shares of common stock outstanding (S) multiplied by the equity accretion rate (V) which is the fraction of sales of new equity investment expected to accrue to existing stockholders. The V term is calculated as 1-(Book Value per Share/Market Price per Share). The sustainable growth rate is then calculated as the sum of BR and SV. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.

### b. Expected Long-Term Growth in the Economy (Stage 3 Growth)

The use of forecast GDP growth in a multi-stage model as the proxy for the rate of growth to which companies will migrate over the longer term is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

### c. Reliability of Analysts' Earnings Forecasts

The reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because some studies have concluded that analysts' earnings growth forecasts have been optimistic. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns.

Analyst optimism became a high profile issue during the irrational exuberance phase of the technology boom during the 1990s, when analysts were accused of fueling the market by exaggerating the prospects of dot.com firms. It was this behaviour that ultimately led to Regulation FD (Fair Disclosure) in 2000 and the Global Analyst Research Settlements of 2002 in the U.S. which removed incentives for sell-side analysts to curry favor with company management by issuing inflated earnings forecasts.

A study conducted after the Global Settlement found that following the settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared.[33] There are also studies which have shown that analyst optimism is at least in part related to the difference between forecasting earnings for firms who report losses versus firms who report profits. For example, Jeffery Abarbanell and Reuven Lehavy, "Biased Forecasts or Biased Earnings? The Role of Reported Earnings in Explaining Apparent Bias and Over/Underreaction in Analysts' Earnings Forecasts", *Journal of Accounting and Economics 36* (2003), pages 105-146, found that while, on an average basis, there appeared to be a forecast bias, the median forecast error was zero. The same article cited an earlier study, Michael P. Keane and David E. Runkle, "Are Financial Analysts' Forecasts of Corporate Profits Rational?", *Journal of Political Economy 100* (1998), pages 768-805, which, when the authors eliminated observations from their data

[33] Armen Hovakimian and Ekkachai Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation", Arizona State University, April 20, 2009.

sample based on the size of negative special items “nearly eliminate evidence of mean optimism in their sample.”

Given the greater transparency of the utility business model (e.g., regulatory filing requirements) relative to some other industries, the more stable operations of utilities, and the value rather than “glamour” nature of utility shares, analyst optimism should be less of an issue with utility earnings forecasts.

The potential bias of the analysts’ growth rates for U.S. utilities was assessed in three separate ways. First, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the Thomson Reuters I/B/E/S ("I/B/E/S") earnings growth forecasts, for which Foster Associates maintains a data base which contains monthly consensus forecasts for utilities back to 1976, were compared to the consensus forecasts of long-term growth. From 1998-2012(Q1), the period of analysis used in the DCF-based risk premium test, the average I/B/E/S forecast long-term earnings growth rate for the sample of low risk U.S. utilities was 5.2%. That growth rate is virtually identical to the average consensus forecast of long-term nominal growth in the economy over the same period. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March and October editions, 1998-2012), was 5.1% from 1998-2012(Q1). The similar expected nominal growth in the economy compared to the I/B/E/S forecasts suggests that the consensus long-term earnings growth forecasts are not an upwardly biased measure of investor expectations.

Second, the I/B/E/S forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* has no incentive to “inflate” its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Since 1998, the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 5.5%, compared to the average I/B/E/S long-term earnings growth rate forecast for the same companies of 5.2%. Again, the higher *Value Line* than I/B/E/S forecasts suggest that the consensus long-term earnings forecasts are not upwardly biased.[34]

Third, allowed returns for U.S. utilities are derived in large part by reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favour the use of forecast growth, while another may favour the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to the estimated constant growth DCF costs of equity for the sample of U.S. utilities estimated using the consensus long-term earnings forecasts over the same period (1998-2012 Q1), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the constant growth DCF models as follows:

[34] In Order G-158-09, December 16, 2009, (page 45), the BCUC stated:

> The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

**Table C-1**

| | | |
|---|---|---|
| **Average Allowed ROEs 1998-2012(Q1)**[1/] | 10.5% | **Average Difference From Allowed ROEs** |
| **Constant Growth DCF Cost of Equity 1998-2012(Q1)** | 9.9% | -0.6% |

[1/] Weighted average.
Sources: Regulatory Research Associates and Schedule 16, page 1 of 4.

The comparison of the DCF costs of equity to the ROEs allowed by regulators provides a further indication that the earnings forecasts are not an upwardly biased measure of investor expectations.

## 4. APPLICATION OF THE DCF MODELS

### a. Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of June 15, 2012 as $D_o$; and,

(2) the average of the daily close prices for the period March 15, 2012 to June 15, 2012 as $P_o$.

The constant growth model was applied using two estimates of long-term growth, the average of four investment analysts' consensus long-term earnings growth forecasts compiled by Bloomberg, Reuters, *Value Line* and Zacks, and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the average of the four consensus earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The sustainable growth rate was derived from the first and second quarter 2012 *Value Line* forecasts as described on page C-5 above.

**b. Three-Stage Model**

The three-stage DCF model applied to the sample of U.S. low risk utilities relied on the average of the four sources of analysts' earnings forecasts for the first five years (Stage 1), the average of the Stage 1 forecast and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). In the three-stage DCF test, the long-run expected nominal rate of growth in GDP of 4.9% was based on the consensus of economists' forecasts for the period 2013-2023 found in Blue Chip *Economic Indicators*, March 1, 2012.[35]

The three-stage DCF test determines the utility cost of equity as the internal rate of return derived from the forecast stream of annual cash flows.

[35] Published twice annually in March and October.

**APPENDIX D**

# DCF-BASED EQUITY RISK PREMIUM TEST

## 1. INTRODUCTION

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model and long-term government bond yields to estimate expected utility returns and risk premiums over time. The utility equity risk premium is measured as the difference between the DCF cost of equity and the yield on long-term government bond yields. The advantage of the DCF-based equity risk premium test is that it allows for testing of the relationship between the utility cost of equity (or the utility equity risk premium) and interest rates.

## 2. SAMPLE OF LOW RISK U.S. UTILITIES

The same sample of U.S. utilities was used to perform the DCF-based equity risk premium tests as for the DCF test. The selection criteria for the sample of U.S. utilities are described in Appendix B.

## 3. CONSTRUCTION OF THE CONSTANT GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

To estimate each monthly sample DCF cost of equity, the monthly published long-term earnings growth rate forecast (**g**) for each of the sample utilities was retrieved from the I/B/E/S data base, from which the monthly sample median was calculated. For each month of the analysis, the current dividend yield (**DY**) for each utility was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield (**$DY_e$**) for the sample was then calculated by adjusting the monthly median dividend yield for the monthly median forecast earnings growth rate **($DY_e$=DY x (1+g))**. The sample DCF cost of equity (DCF) in each month was calculated by combining the forecast growth rate and the expected dividend yield. The monthly utility sample equity risk premium **(ERP)** was calculated by subtracting the corresponding 30-year Treasury bond yield **(TY)** from the DCF cost of equity **(ERP=DCF–TY)**. The annual averages of the monthly utility sample constant growth DCF costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 16, page 1 of 4.

## 4. CONSTRUCTION OF THE THREE-STAGE GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

A three-stage growth model was also used in the application of the DCF-based equity risk premium test. As with the constant growth model, monthly estimates of the DCF cost of equity were made for the sample, using the sample median dividend yield as the point of departure.

For the forecast growth rates, the first stage (Years 1 to 5) of the model used the sample median I/B/E/S forecast growth rate published in that month. For the third stage (Years 11 and beyond), the expected growth rate was represented by the most recent long-term nominal GDP growth rate forecast available in that month from Blue Chip *Financial Forecasts*. Blue Chip *Financial Forecasts* publishes long-term GDP growth forecasts in June and December of each year. Therefore, as examples, the Stage 3 expected growth rate for the months June through November 2009 was represented by the nominal GDP growth forecast published in June 2009. The Stage 3 expected growth rate for the months December 2009 through May 2010 was represented by the December 2009 long-term nominal GDP forecast. Similar to the three-stage DCF test, Stage 2 growth (Years 6 to 10) is equal to the average of Stage 1 and Stage 3 growth rates.

For each month of the analysis, the DCF cost of equity was then determined for the utility sample using the forecast stream of annual cash flows to derive the internal rate of return.

As with the constant growth DCF-based risk premium test, the utility sample monthly equity risk premium **(ERP)** was calculated by subtracting the corresponding 30-year Treasury bond yield **(TY)** from the monthly DCF cost of equity **(ERP=DCF–TY).** The annual averages of the three-stage DCF model costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 16, page 3 of 4.

**APPENDIX E**

# COMPARABLE EARNINGS TEST

## 1. SELECTION OF CANADIAN UNREGULATED COMPANIES

The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonably comparable investment risk to utilities.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[36] The resulting universe contained 516 firms. Companies were removed which:

1. For which no common equity balance data was reported for any year 2000-2010 by S&P's Research Insight data base,
2. Had negative common equity for any year from 1994-2011 for which data were available from S&P's Research Insight data base,

[36] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

3. Are income trusts or incorporated outside Canada,
4. Paid no dividends in any year 2007 to 2011,
5. Had less than five years of market data,
6. Had total assets less than $500 million,
7. Had a 2010 equity ratio (including short term debt) less than 50%,
8. Had an average 2010-2011 "raw" beta over 1.0, and
9. Had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor's.

The final sample of low risk Canadian unregulated companies is comprised of 21 companies (Schedule 24).

## 2. TIME PERIOD FOR MEASURING RETURNS

Since unregulated companies' returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1995-2011 constitutes a full business cycle, commencing with 1995 (the third full year of expansion following the 1991-1992 recession), including the 2008-2009 recession and the first two full years of recovery (2010-2011). Over the period 1995-2011, the experienced returns on equity of the sample of 21 low risk unregulated Canadian companies were as follows.

**Table E-1**

| ROEs for Low Risk Canadian Unregulated Companies (1995-2011) | |
|---|---|
| Average | 13.7% |
| Median | 12.8% |
| Average of Annual Medians | 13.4% |

Source: Schedule 25.

Based on these data, the ROEs for the low risk Canadian unregulated companies are in the approximate range of 12.75-13.75%.

The annual nominal economic compound growth for Canada during the 1995-2011 business cycle was 4.8%. The historic annual nominal compound growth rate over the full business cycle is somewhat higher than the forecast nominal GDP growth rate of approximately 4.3% from 2013 to 2022.[37]

In light of the lower forecast economic growth compared to the historical level, the achieved equity returns for the sample were also calculated over a shorter and more recent period of time (2004 to 2011) with a rate of economic growth closer to the forecast rate. This period commences with the third full year following the 2001 economic downturn, and, similar to the longer period, includes the 2008-2009 recession and the first two full years of recovery. Over the period 2004-2011, the nominal economic compound growth in Canada was 4.5%, slightly higher than the average rate of growth forecast for the period 2012-2022**.**

[37] Based on Consensus Economics, *Consensus Forecasts*, April 2012, which anticipate real GDP growth of 2.25% and CPI inflation of 2.0% from 2013 to 2022.

The experienced returns on equity of the sample of 21 low risk unregulated Canadian companies during 2004-2011 were as follows.

**Table E-2**

| **ROEs for Low Risk Canadian Unregulated Companies (2004-2011)** | |
|---|---|
| Average | 13.2% |
| Median | 12.3% |
| Average of Annual Medians | 13.5% |

Source: Schedule 25

Since nominal growth is forecast to be only slightly higher than that experienced rate during 2004-2011, the experienced returns on book equity for this period of approximately 12.25% to 13.5%, absent extraordinary events, provide a reasonable proxy for the future.

## 3. RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian unregulated companies relative to Canadian utilities, comparisons of debt ratings and betas indicate that the unregulated companies are of somewhat higher risk than the utilities. For the unregulated companies with debt ratings, the median S&P and DBRS ratings are BBB and BBB/BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 4 and 24). Based on medians, the average adjusted monthly beta for the unregulated companies for the five-year periods ending December 2004-2011 was 0.64 (see Schedule 24), compared to a 0.48 adjusted monthly beta for the major publicly-traded Canadian utilities over the same time period (Schedule 14 page 1 of 6).

There is no universally accepted methodology for making a downward adjustment to the unregulated low risk company returns on common equity for the lower risk of utilities. The difference in yields on A-rated utility bonds and BBB-rated corporate bonds provides one measure of a reasonable downward adjustment. Historically the average difference has been close to 75 basis points. Relative adjusted betas of the unregulated companies and Canadian utilities were also used as an alternative indicator of the magnitude of the downward adjustment warranted, with the caveat that the recent low calculated Canadian utility betas may result in an overestimate of the downward adjustment required. When applied to the difference between the achieved ROEs and the longer-term forecast 30-year Canada bond yield of approximately 5.0%, the relative historic adjusted betas suggest a downward adjustment of approximately 2.0%. Together the bond yield spreads and relative adjusted betas indicate that a downward adjustment to the unregulated companies' ROEs in the range of 0.75% to 2.0% (mid-point of approximately 1.25% to 1.50%) would be reasonably conservative. The resulting fair ROE for the benchmark BC utility based on the comparable earnings test is approximately 11.0% to 12.0%.

## 4. MARKET/BOOK RATIOS

The argument that a downward adjustment to the comparable earnings test results for the market/book ratios of the unregulated companies has been made on the following bases:

a. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.

b. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

Both of these arguments are without merit. With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the "Q Ratio", a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.[38] Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the "Q Ratio" (market value/replacement cost) should trend toward 1.0.

The "Q Ratio" has since gained stature as an investment tool,[39] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

> Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin's work.
>
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. <u>While the Q ratio – as Tobin's Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today</u>. [emphasis added]

Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

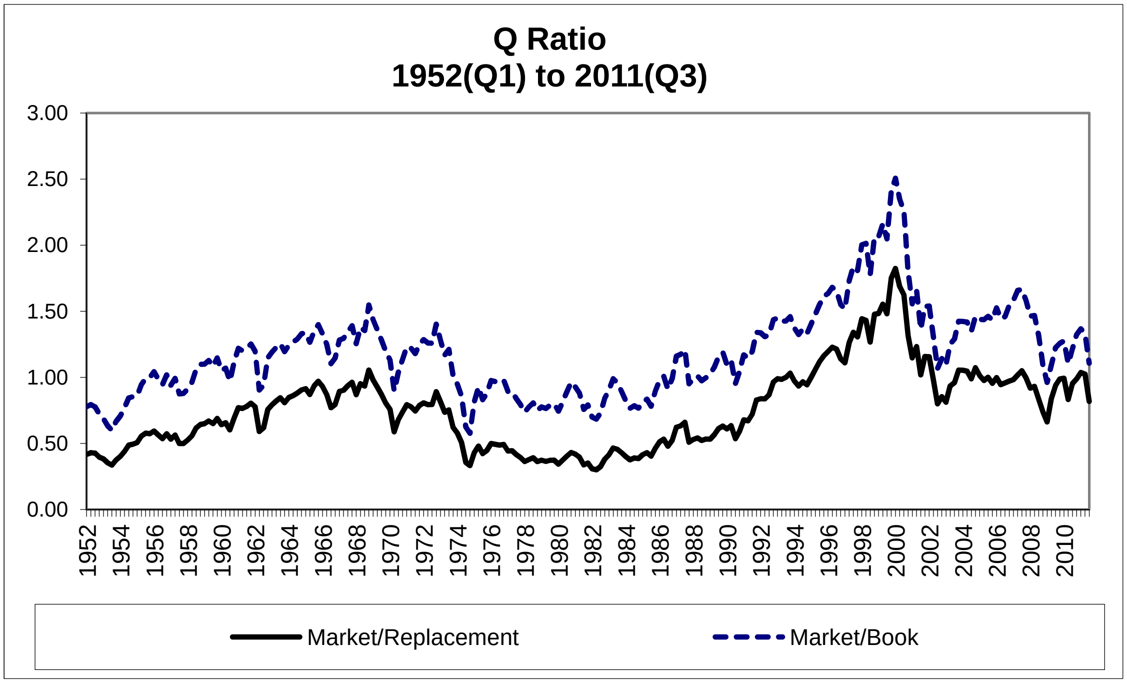
---

[38] The general idea had been expressed decades earlier by the economist John Keynes.

[39] The Federal Reserve Board tracks the "Q Ratio" of the U.S. equity market. It was the level of the "Q Ratio", along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

As indicated in Figure E-1 below, market/replacement cost ratios for U.S. firms, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations[40] has averaged approximately 30% lower than the market/book ratio over the business cycle 1995-2011Q3

**Figure E-1**

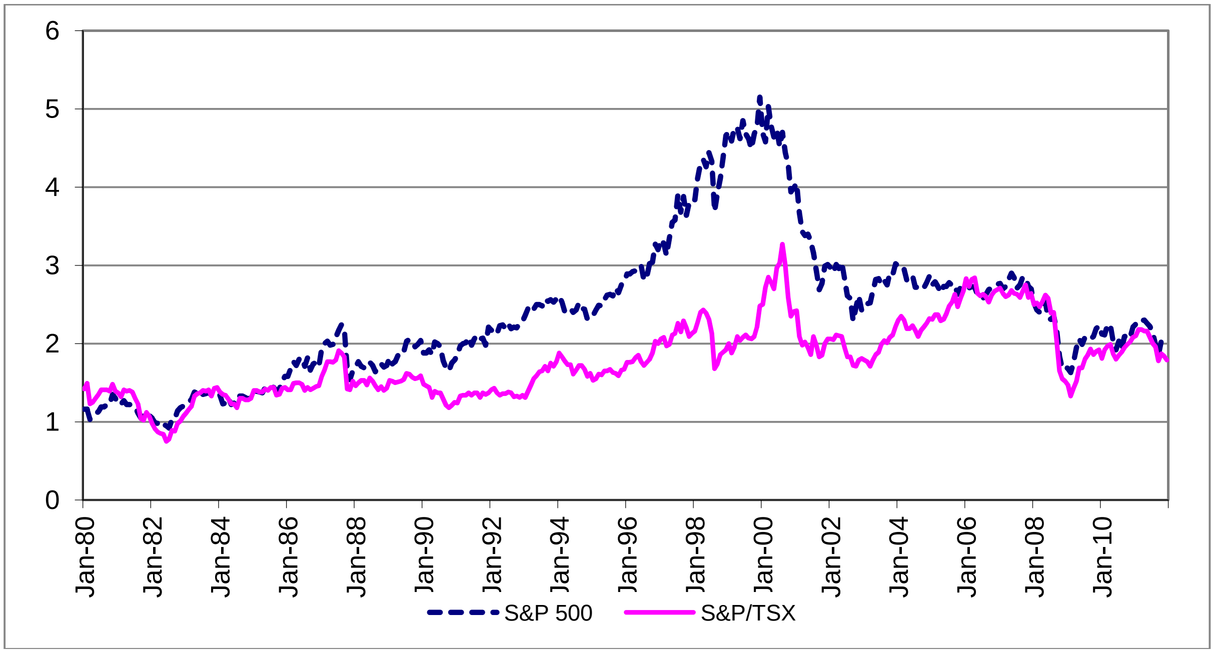



Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the sample of low risk unregulated Canadian firms used in the comparable earnings test, their market/book ratios were compared to those of Canadian and U.S. equity market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2011.

[40] Based on non-farm, non-financial corporate businesses.

**Figure E-2**




Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.8 times from 1980-2011, and 2.1 times from 1995-2011, the last full business cycle and 2.2 times from 2004-2011, the period over which the comparable earnings test was conducted. Based on over three decades of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.8 times, not 1.0 times. For the S&P 500, the market/book ratios were approximately 2.4 times, 3.0 times, and 2.4 times respectively, over the same three periods. Over the periods 1995-2011 and 2004-2011, the market/book ratios for the sample of comparable Canadian unregulated companies averaged 2.3 times and 2.2 times, respectively, approximately equal to the average market/book ratios for the S&P/TSX Composite and lower than the market/book ratio of the S&P 500. The similar to lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian and U.S. equity market composites permit the inference that the sample average returns are not characterized by market power. Thus, no adjustment to the comparable earnings results is warranted for the market/book ratios of the low risk unregulated companies.

# APPENDIX F

# FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[41]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

[41] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[42]

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for \$100,000 and took out a mortgage for the full amount. My home is currently worth \$250,000 and my mortgage is now \$85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be \$165,000 (market value of \$250,000 less the \$85,000 unpaid mortgage), not

---

[42] The minimum financing flexibility allowance can be estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x "bare-bones" Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a retention rate of 25% and a "bare-bones" cost of equity of 9.5%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \times 9.5\%}{1 + [.25\,(1.075 - 1.0)]}$$

$$\text{ROE} = 10.0\%$$

The difference of 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

the "book value" of the equity in my home of $15,000, which reflects the original purchase price less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

The rationale for the differences in the required return on equity for companies of similar business risk but different financial risk begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. In the absence of both the deductibility of interest expense for corporate income tax purposes and costs associated with excessive debt (e.g., bankruptcy), the overall cost of capital to a firm would not change when a firm changes its capital structure.[43]

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. However, in a competitive environment, the sum of the available cash flows does not change when debt is added to the capital structure. The available cash flows are now split between debt and equity holders. Since there are fixed debt costs that must be paid before the equity shareholder receives any return, the variability of the equity return increases as debt rises. The higher the debt ratio, the higher the potential volatility of the equity return and the greater the risk that equity shareholders will not recover their invested capital and a compensatory return thereon. Hence, as the debt ratio rises, the cost of equity rises. The higher cost rates of both the debt and equity offset the higher proportion of debt in the capital structure, so that the overall cost of capital does not change.

The deductibility of interest expense for corporate income tax purposes alters the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense

[43] The seminal theory, which was premised on no risk to excessive debt, was set out in Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48: 261-297 (June 1958).

for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. In the absence of offsetting factors, when interest expense is deductible for corporate income tax purposes, the after-tax cost of capital declines as more debt is used.[44]

Offsetting some of the advantage of debt at the corporate level are the higher personal tax rates on interest income than on dividend income and capital gains. When personal income tax rates on dividends and capital gains are lower than the personal income tax rate on interest income, all other things equal, taxable investors would prefer firms to use equity rather than debt. If taxes were the only consideration, there are combinations of corporate and personal income taxes at which the corporate tax advantages of using debt are completely offset by the personal tax advantages to holding equity rather than debt.[45]

However, factors other than taxes impact the choice of capital structure. The addition of debt to the capital structure is not risk-free. There is a loss of financial flexibility and an increasing potential for bankruptcy as the debt ratio rises. The result is an increase in the cost of capital as leverage is increased. For example, as the percentage of debt in the capital structure increases, the company's credit rating may decline and its cost of debt will increase. When the loss of financing flexibility and costs of financial distress impair a firm's ability to operate efficiently, e.g., to pursue opportunities to grow the business or even to obtain trade credit as required, the cost of equity and the overall cost of capital will likely increase more than pure theory would indicate.

It is impossible to state with precision whether, within a specific range of capital structures, raising the debt ratio will leave the overall cost of capital unchanged or result in some decline. However, what is indisputable is that the cost of equity does change when the debt ratio changes, increasing when the debt ratio increases and, conversely, decreasing when the debt ratio falls.

---

[44] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

[45] The offsetting impacts of lower personal tax rates on equity income compared to interest income were examined in Merton H. Miller, "Debt and Taxes," *The Journal of Finance*, 32: 261-276 (May 1977). At the 2011 marginal corporate and personal income tax rates (on interest, dividends and capital gains) in Canada, the gain from corporate leverage is relatively small.

The cost of equity has been estimated using samples of comparable proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the book value capital structure. Regulatory convention applies the allowed ROE to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Three approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity when interest expense is deductible for income tax purposes.

Approach 1 is based on the theory that the overall after-tax cost of capital and the pre-tax cost of capital do not change materially over a relatively broad range of capital structures. This approach effectively assumes that the benefit of the deductibility of interest expense for corporate income tax purposes (which would tend to lower the overall cost of capital) is offset by personal income taxes on interest.

Approach 2 is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

Approach 3 assumes for utility cost of capital purposes that the corporate income tax rate is zero. The underlying premise is that the benefits of the corporate tax deductibility of interest accrue to rate payers, not shareholders, as is the case with unregulated companies. As with the first approach, the overall cost of capital remains unchanged as the capital structure changes. However, since the cost of capital contains no income tax component, the impact on the cost of equity due to changing leverage is less than in the presence of corporate income tax and interest deductibility.

Table F-1 below shows the adjustments to the cost of equity that are required to recognize the difference in financial risk between the market value capital structures of the Canadian and U.S. utility samples and the book value capital structures under the three approaches. Schedule 27 provides the formulas for estimating the change in the cost of equity due to capital structure differences under Approaches 1 and 2. When the corporate income tax rate is zero, Approach 1 and 2 result in the same adjustment to the ROE as Approach 3.

**Table F-1**

| | Cost of Equity | Market Value Equity Ratio | Book Value Equity Ratio | Adjustment to ROE for Book Value Capital Structure | | |
|---|---|---|---|---|---|---|
| | | | | Approach 1 26.25% tax rate | Approach 2 26.25% tax rate | Approach 3 0% tax rate |
| Canadian Utilities | 9.6% | 57% | 40% | 2.4% | 1.5% | 1.8% |
| U.S. Utilities | 9.6% | 62% | 49% | 1.4% | 0.9% | 1.0% |

Notes: Based on incremental utility cost of long-term debt of 5.35%.
Corporate income tax rate of 26.25% is estimated combined 2013 federal/provincial tax rate for Canada.

Source: Schedule 27

Full recognition of the difference in financial risk between the market value equity ratios of the publicly-traded Canadian utilities (57%) and the U.S. utilities (62%) and the average book value common equity ratio of investor-owned Canadian regulated utilities (40%) and the U.S. utilities (49%) equity (Schedules 5, 6, and 26) results in an adjustment to the "bare bones" cost of equity in the range of approximately 1.0% to 2.0% (mid-point of approximately 1.5%, or 150 basis points).

**APPENDIX G**

# QUALIFICATIONS OF KATHLEEN C. MCSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

## PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?*, presented at the 24$^{th}$ Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

**EXPERT TESTIMONY/OPINIONS**
**ON**
**RATE OF RETURN AND CAPITAL STRUCTURE**

***Alberta Natural Gas***
1994

***Alberta Utilities Generic Cost of Capital***
2011

***AltaGas Utilities***
2000

***Ameren (Central Illinois Public Service)***
2000, 2002, 2005, 2007 (2 cases),
2009 (2 cases)

***Ameren (Central Illinois Light Company)***
2005, 2007 (2 cases), 2009 (2 cases)

***Ameren (Illinois Power)***
2004, 2005, 2007 (2 cases), 2009 (2 cases)

***Ameren (Union Electric)***
2000 (2 cases), 2002 (2 cases), 2003,
2006 (2 cases)

***ATCO Electric***
1989, 1991, 1993, 1995, 1998, 1999, 2000,
2003, 2010

***ATCO Gas***
2000, 2003, 2007

***ATCO Pipelines***
2000, 2003, 2007, 2011

***ATCO Utilities***
(Generic Cost of Capital) 2008

***Bell Canada***
1987, 1993

***Benchmark Utility Cost of Equity (British Columbia)***
1999

***Canadian Western Natural Gas***
1989, 1996, 1998, 1999

***Centra Gas B.C.***
1992, 1995, 1996, 2002

***Centra Gas Ontario***
1990, 1991, 1993, 1994, 1995

***Direct Energy Regulated Services***
2005

***Dow Pool A Joint Venture***
1992

***Electricity Distributors Association***
2009

***Enbridge Gas Distribution***
1988, 1989, 1991, 1992, 1993, 1994, 1995,
1996, 1997, 2001, 2002

***Enbridge Gas New Brunswick***
2000, 2010

***Enbridge Pipelines (Line 9)***
2007, 2009

***Enbridge Pipelines (Southern Lights)***
2007

***EPCOR Water Services Inc.***
1994, 2000, 2006, 2008, 2011

***FortisBC***
1995, 1999, 2001, 2004

***FortisBC Energy Inc.***
1992, 1994, 2005, 2009, 2011

***FortisBC Energy (Whistler) Inc.***
2008

***Gas Company of Hawaii***
2000, 2008

***Gaz Métro***
1988

***Gazifère***
1993, 1994, 1995, 1996, 1997, 1998, 2010

***Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)***
2003

***Heritage Gas***
2004, 2008, 2011

***Hydro One***
1999, 2001, 2006 (2 cases)

***Insurance Bureau of Canada (Newfoundland)***
2004

***Laclede Gas Company***
1998, 1999, 2001, 2002, 2005

***Laclede Pipeline***
2006

***Mackenzie Valley Pipeline***
2005

***Maritime Electric***
2010

***Maritimes NRG (Nova Scotia) and (New Brunswick)***
1999

***MidAmerican Energy Company***
2009

***Multi-Pipeline Cost of Capital Hearing (National Energy Board)***
1994

***Natural Resource Gas***
1994, 1997, 2006, 2010

***New Brunswick Power Distribution***
2005

***Newfoundland & Labrador Hydro***
2001, 2003

***Newfoundland Power***
1998, 2002, 2007, 2009, 2012

***Newfoundland Telephone***
1992

***Northland Utilities***
2008 (2 cases)

***Northwestel, Inc.***
2000, 2006

***Northwestern Utilities***
1987, 1990

***Northwest Territories Power Corp***.
1990, 1992, 1993, 1995, 2001, 2006

***Nova Scotia Power Inc.***
2001, 2002, 2005, 2008, 2011, 2012

***Ontario Power Generation***
2007, 2010

***Ozark Gas Transmission***
2000

***Pacific Northern Gas***
1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009

***Plateau Pipe Line Ltd.***
2007

***Platte Pipeline Co.***
2002

***St. Lawrence Gas***
1997, 2002

***Southern Union Gas***
1990, 1991, 1993

***Stentor***
1997

***Tecumseh Gas Storage***
1989, 1990

***Telus Québec***
2001

***TransCanada PipeLines***
1988, 1989, 1991 (2 cases), 1992, 1993

***TransGas and SaskEnergy LDC***
1995

***Trans Québec & Maritimes Pipeline***
1987

***Union Gas***
1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001

***Westcoast Energy***
1989, 1990, 1992 (2 cases), 1993, 2005

***Yukon Electrical Company***
1991, 1993, 2008

***Yukon Energy***
1991, 1993

# EXPERT TESTIMONY/OPINIONS
ON
# OTHER ISSUES

| Client | Issue | Date |
|---|---|---|
| Greater Toronto Airports Authority | Financial Performance Metrics | 2012 |
| Heritage Gas | Criteria for a Mature Utility | 2011 |
| Alberta Utilities | Management Fee on CIAC | 2011 |
| Maritimes & Northeast Pipeline | Return on Escrow Account | 2010 |
| Nova Scotia Power | Calculation of ROE | 2009 |
| Alberta Oilsands Pipeline | Cash Working Capital | 2007 |
| New Brunswick Power Distribution | Interest Coverage/Capital Structure | 2007 |
| Heritage Gas | Revenue Deficiency Account | 2006 |
| Hydro Québec | Cash Working Capital | 2005 |
| Nova Scotia Power | Cash Working Capital | 2005 |
| Ontario Electricity Distributors | Stand-Alone Income Taxes | 2005 |
| Caisse Centrale de Réassurance | Collateral Damages | 2004 |
| Hydro Québec | Cost of Debt | 2004 |
| Enbridge Gas New Brunswick | AFUDC | 2004 |
| Heritage Gas | Deferral Accounts | 2004 |
| ATCO Electric | Carrying Costs on Deferral Account | 2001 |
| Newfoundland & Labrador Hydro | Rate Base, Cash Working Capital | 2001 |
| Gazifère Inc. | Cash Working Capital | 2000 |
| Maritime Electric | Rate Subsidies | 2000 |
| Enbridge Gas Distribution | Principles of Cost Allocation | 1998 |
| Enbridge Gas Distribution | Unbundling/Regulatory Compact | 1998 |
| Maritime Electric | Form of Regulation | 1995 |
| Northwest Territories Power | Rate Stabilization Fund | 1995 |
| Canadian Western Natural Gas | Cash Working Capital/Compounding Effect | 1989 |
| Gaz Métro/Province of Québec | Cost Allocation/Incremental vs. Rolled-In Tolling | 1984 |

# SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

| | | Canada | | | | | | | United States | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Gross Domestic Product | | | | | After-Tax Profits | | Gross Domestic Product | | | | | After-Tax Profits | |
| Year | | Constant Dollars (1) | Current Dollars (2) | Industrial Production (3) | GDP Deflator Index (4) | Consumer Price Index (5) | Billions of Dollars (6) | As Percent of GDP (7) | Constant Dollars (8) | Current Dollars (9) | Industrial Production (10) | Implicit Price Index (11) | Consumer Price Index (12) | Billions of Dollars (13) | As Percent of GDP (14) |
| 1989 | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 41 | 6.3% | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 244 | 4.5% |
| 1990 | | 100.2 | 103.4 | 97.2 | 103.2 | 104.8 | 28 | 4.1% | 101.9 | 105.8 | 101.0 | 103.9 | 105.4 | 266 | 4.6% |
| 1991 | | 98.1 | 104.2 | 93.5 | 106.2 | 110.7 | 18 | 2.6% | 101.6 | 109.3 | 99.4 | 107.5 | 109.8 | 287 | 4.8% |
| 1992 | | 99.0 | 106.5 | 94.5 | 107.6 | 112.3 | 18 | 2.6% | 105.1 | 115.7 | 102.2 | 110.1 | 113.2 | 326 | 5.1% |
| 1993 | | 101.3 | 110.6 | 98.8 | 109.2 | 114.4 | 25 | 3.4% | 108.1 | 121.6 | 105.6 | 112.5 | 116.5 | 348 | 5.2% |
| 1994 | | 106.1 | 117.2 | 105.1 | 110.4 | 114.6 | 46 | 6.0% | 112.5 | 129.2 | 111.1 | 114.9 | 119.5 | 406 | 5.7% |
| 1995 | | 109.1 | 122.7 | 109.9 | 112.9 | 117.1 | 54 | 6.7% | 115.3 | 135.3 | 116.4 | 117.3 | 122.9 | 466 | 6.3% |
| 1996 | | 110.9 | 126.8 | 111.8 | 114.7 | 118.9 | 54 | 6.5% | 119.6 | 143.0 | 121.6 | 119.5 | 126.5 | 509 | 6.5% |
| 1997 | | 115.6 | 133.5 | 118.0 | 116.1 | 120.8 | 56 | 6.3% | 125.0 | 152.0 | 130.4 | 121.6 | 129.5 | 556 | 6.7% |
| 1998 | | 120.3 | 139.2 | 122.2 | 115.6 | 122.0 | 55 | 6.0% | 130.4 | 160.4 | 137.9 | 123.0 | 131.5 | 475 | 5.4% |
| 1999 | | 127.0 | 149.4 | 129.8 | 117.6 | 124.2 | 71 | 7.3% | 136.7 | 170.6 | 143.9 | 124.8 | 134.4 | 522 | 5.6% |
| 2000 | | 133.6 | 163.5 | 139.6 | 122.5 | 127.5 | 88 | 8.1% | 142.4 | 181.5 | 149.6 | 127.5 | 138.9 | 507 | 5.1% |
| 2001 | | 136.0 | 168.5 | 134.6 | 123.9 | 130.8 | 91 | 8.2% | 143.9 | 187.6 | 144.5 | 130.4 | 142.8 | 509 | 5.0% |
| 2002 | | 140.0 | 175.3 | 137.5 | 125.2 | 133.7 | 99 | 8.6% | 146.5 | 194.1 | 144.7 | 132.5 | 145.1 | 573 | 5.4% |
| 2003 | | 142.6 | 184.4 | 137.7 | 129.4 | 137.4 | 105 | 8.6% | 150.2 | 203.2 | 146.5 | 135.3 | 148.4 | 570 | 5.9% |
| 2004 | | 147.0 | 196.3 | 139.8 | 133.5 | 139.9 | 122 | 9.4% | 155.4 | 216.2 | 149.9 | 139.1 | 152.3 | 923 | 7.8% |
| 2005 | | 151.5 | 208.9 | 142.1 | 137.9 | 143.0 | 138 | 10.0% | 160.2 | 230.3 | 154.8 | 143.7 | 157.5 | 1,228 | 9.7% |
| 2006 | | 155.8 | 220.5 | 142.1 | 141.6 | 145.9 | 140 | 9.7% | 164.5 | 244.0 | 158.2 | 148.4 | 162.6 | 1,349 | 10.1% |
| 2007 | | 159.2 | 232.6 | 141.4 | 146.1 | 149.0 | 146 | 9.5% | 167.6 | 255.9 | 162.1 | 152.7 | 167.2 | 1,293 | 9.2% |
| 2008 | | 160.3 | 243.8 | 137.1 | 152.1 | 152.6 | 168 | 10.5% | 167.0 | 260.7 | 156.4 | 156.1 | 173.6 | 1,051 | 7.3% |
| 2009 | | 155.8 | 232.5 | 124.1 | 149.2 | 153.0 | 96 | 6.3% | 161.2 | 254.3 | 138.5 | 157.7 | 173.0 | 1,183 | 8.5% |
| 2010 | | 160.9 | 247.0 | 130.2 | 153.6 | 155.7 | 126 | 7.7% | 166.1 | 265.0 | 146.0 | 159.5 | 175.9 | 1,408 | 9.7% |
| 2011 | | 164.8 | 261.3 | 134.7 | 158.6 | 160.3 | 153 | 8.9% | 169.0 | 275.3 | 152.0 | 162.9 | 181.4 | 1,480 | 9.8% |
| 2007 | Q1 | 157.6 | 227.6 | 142.4 | 144.4 | 147.4 | 139 | 9.3% | 165.7 | 251.0 | 160.5 | 151.5 | 164.3 | 1,264 | 9.2% |
| | Q2 | 158.9 | 232.5 | 142.3 | 146.3 | 149.6 | 144 | 9.4% | 167.2 | 255.0 | 162.3 | 152.5 | 167.5 | 1,316 | 9.4% |
| | Q3 | 159.7 | 233.4 | 141.4 | 146.2 | 149.6 | 148 | 9.6% | 168.4 | 257.7 | 162.7 | 153.0 | 167.9 | 1,284 | 9.1% |
| | Q4 | 160.5 | 236.7 | 139.7 | 147.4 | 149.5 | 152 | 9.8% | 169.1 | 260.0 | 163.0 | 153.7 | 169.1 | 1,308 | 9.2% |
| 2008 | Q1 | 160.3 | 240.3 | 138.2 | 150.0 | 150.0 | 163 | 10.3% | 168.4 | 260.4 | 162.5 | 154.6 | 171.0 | 1,188 | 8.3% |
| | Q2 | 160.5 | 246.5 | 137.6 | 153.6 | 153.1 | 181 | 11.2% | 168.9 | 263.0 | 160.1 | 155.7 | 174.8 | 1,208 | 8.4% |
| | Q3 | 160.9 | 249.3 | 138.0 | 155.0 | 154.7 | 186 | 11.4% | 167.4 | 262.6 | 154.8 | 156.9 | 176.8 | 1,163 | 8.1% |
| | Q4 | 159.4 | 239.0 | 134.4 | 150.0 | 152.4 | 142 | 9.0% | 163.5 | 256.9 | 148.2 | 157.1 | 171.8 | 644 | 4.6% |
| 2009 | Q1 | 156.1 | 230.7 | 128.0 | 147.8 | 151.9 | 105 | 6.9% | 160.7 | 253.4 | 140.4 | 157.7 | 171.0 | 1,000 | 7.2% |
| | Q2 | 154.7 | 229.3 | 122.6 | 148.3 | 153.2 | 93 | 6.2% | 160.4 | 252.7 | 136.2 | 157.5 | 172.8 | 1,099 | 7.9% |
| | Q3 | 155.3 | 232.0 | 121.6 | 149.5 | 153.4 | 91 | 6.0% | 161.1 | 253.9 | 137.9 | 157.6 | 174.0 | 1,244 | 8.9% |
| | Q4 | 157.2 | 237.8 | 124.1 | 151.3 | 153.6 | 93 | 6.0% | 162.6 | 257.0 | 139.8 | 158.0 | 174.3 | 1,390 | 9.9% |
| 2010 | Q1 | 159.4 | 243.4 | 127.3 | 152.7 | 154.4 | 109 | 6.8% | 164.2 | 260.4 | 142.4 | 158.6 | 175.0 | 1,416 | 9.9% |
| | Q2 | 160.3 | 244.8 | 130.1 | 152.8 | 155.3 | 114 | 7.1% | 165.7 | 263.9 | 145.4 | 159.2 | 175.8 | 1,466 | 10.1% |
| | Q3 | 161.3 | 247.1 | 131.0 | 153.3 | 156.2 | 133 | 8.2% | 166.8 | 266.4 | 147.8 | 159.8 | 176.0 | 1,414 | 9.7% |
| | Q4 | 162.5 | 252.7 | 132.3 | 155.6 | 157.1 | 146 | 8.8% | 167.7 | 269.1 | 148.6 | 160.5 | 176.5 | 1,338 | 9.1% |
| 2011 | 1Q | 164.0 | 257.5 | 134.3 | 157.1 | 158.4 | 152 | 9.0% | 167.9 | 271.2 | 150.2 | 161.6 | 178.8 | 1,455 | 9.8% |
| | 2Q | 163.7 | 258.9 | 132.8 | 158.2 | 160.6 | 144 | 8.5% | 168.4 | 273.9 | 150.6 | 162.6 | 181.9 | 1,470 | 9.8% |
| | 3Q | 165.4 | 262.4 | 135.4 | 158.7 | 160.9 | 152 | 8.8% | 169.2 | 276.8 | 152.7 | 163.6 | 182.6 | 1,502 | 9.9% |
| | 4Q | 166.1 | 266.4 | 136.2 | 160.5 | 161.3 | 164 | 9.4% | 170.4 | 279.4 | 154.5 | 164.0 | 182.3 | 1,494 | 9.8% |

Note: Data are based on Chain Weighted Indexes.

Source: www.bea.gov, www.cansim2.statcan.ca, www.federalreserve.gov

**TREND IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS**
**(Percent Per Annum)**

| | Canada | | | | | | | | | | | Moody's U.S. Utility Long-Term A-Rated Bonds | Exchange Rate (Cdn$/US$) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Government Securities | | | | | | | | | | | | |
| | T-Bills | | 10 Year | | Long-Term | | Bonds Over 10 Years [3] | Inflation Indexed Bonds | A-Rated Utility Bonds [4] | Median Utility Dividend Yield [5] | A-Rated Utility/ Long Canada Bond Yield Spread | | |
| Year | Canadian | U.S. [1] | Canadian | U.S. | Canadian | U.S. [2] | | | | | | | |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
| Annual | | | | | | | | | | | | | |
| 1990 | 12.81 | 7.49 | 10.76 | 8.55 | 10.69 | 8.61 | 10.85 | | 12.13 | | 1.44 | 9.86 | 0.86 |
| 1991 | 8.73 | 5.38 | 9.42 | 7.86 | 9.72 | 8.14 | 9.76 | | 11.00 | | 1.28 | 9.36 | 0.84 |
| 1992 | 6.59 | 3.43 | 8.05 | 7.01 | 8.68 | 7.67 | 8.77 | 4.62 | 10.01 | | 1.33 | 8.69 | 0.82 |
| 1993 | 4.84 | 3.02 | 7.22 | 5.87 | 7.86 | 6.59 | 7.85 | 4.28 | 9.08 | 6.08 | 1.22 | 7.59 | 0.77 |
| 1994 | 5.54 | 4.34 | 8.43 | 7.08 | 8.69 | 7.39 | 8.63 | 4.41 | 9.81 | 6.12 | 1.12 | 8.30 | 0.73 |
| 1995 | 6.89 | 5.44 | 8.08 | 6.58 | 8.41 | 6.85 | 8.28 | 4.68 | 9.29 | 6.42 | 0.88 | 7.89 | 0.73 |
| 1996 | 4.21 | 5.04 | 7.20 | 6.44 | 7.75 | 6.73 | 7.50 | 4.61 | 8.38 | 5.66 | 0.63 | 7.75 | 0.73 |
| 1997 | 3.26 | 5.11 | 6.11 | 6.32 | 6.66 | 6.58 | 6.42 | 4.14 | 7.19 | 4.57 | 0.53 | 7.60 | 0.72 |
| 1998 | 4.73 | 4.79 | 5.30 | 5.26 | 5.59 | 5.54 | 5.47 | 4.02 | 6.38 | 4.23 | 0.79 | 7.04 | 0.68 |
| 1999 | 4.69 | 4.71 | 5.55 | 5.68 | 5.72 | 5.91 | 5.69 | 4.07 | 6.92 | 5.00 | 1.20 | 7.62 | 0.67 |
| 2000 | 5.45 | 5.85 | 5.89 | 5.98 | 5.71 | 5.88 | 5.89 | 3.69 | 7.05 | 5.63 | 1.34 | 8.24 | 0.67 |
| 2001 | 3.78 | 3.34 | 5.49 | 4.99 | 5.77 | 5.50 | 5.76 | 3.59 | 7.10 | 4.57 | 1.33 | 7.74 | 0.65 |
| 2002 | 2.55 | 1.63 | 5.27 | 4.56 | 5.67 | 5.41 | 5.65 | 3.49 | 7.08 | 3.97 | 1.41 | 7.34 | 0.64 |
| 2003 | 2.86 | 1.03 | 4.78 | 4.02 | 5.31 | 5.03 | 5.26 | 3.04 | 6.65 | 3.80 | 1.33 | 6.54 | 0.72 |
| 2004 | 2.21 | 1.44 | 4.55 | 4.27 | 5.11 | 5.08 | 5.05 | 2.34 | 6.14 | 3.69 | 1.03 | 6.14 | 0.77 |
| 2005 | 2.73 | 3.29 | 4.04 | 4.27 | 4.38 | 4.52 | 4.36 | 1.81 | 5.43 | 3.23 | 1.05 | 5.62 | 0.83 |
| 2006 | 4.05 | 4.86 | 4.21 | 4.79 | 4.26 | 4.87 | 4.28 | 1.67 | 5.36 | 3.19 | 1.09 | 6.06 | 0.89 |
| 2007 | 4.13 | 4.42 | 4.25 | 4.58 | 4.30 | 4.80 | 4.31 | 1.95 | 5.52 | 3.26 | 1.22 | 6.06 | 0.94 |
| 2008 | 2.26 | 1.28 | 3.56 | 3.61 | 4.04 | 4.22 | 4.03 | 1.90 | 6.29 | 3.62 | 2.26 | 6.54 | 0.94 |
| 2009 | 0.31 | 0.15 | 3.27 | 3.29 | 3.85 | 4.10 | 3.85 | 1.86 | 6.10 | 4.20 | 2.24 | 5.99 | 0.88 |
| 2010 | 0.59 | 0.14 | 3.17 | 3.14 | 3.70 | 4.17 | 3.63 | 1.36 | 5.20 | 3.78 | 1.51 | 5.38 | 0.97 |
| 2011 | 0.91 | 0.06 | 2.76 | 2.75 | 3.26 | 3.86 | 3.19 | 0.92 | 4.82 | 3.50 | 1.56 | 5.00 | 1.02 |
| 2012 (Jun) | 0.93 | 0.08 | 1.92 | 1.88 | 2.50 | 2.99 | 2.39 | 0.45 | 4.09 | 3.62 | 1.59 | 4.26 | 0.99 |

[1/] Rates on new issues.

[2/] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006, when no 30-year Treasury bonds were issued. The theoretical 30-year Treasury bond yield represents the yield on all outstanding Treasury bonds with a term to maturity greater than 25 years plus an extrapolation factor published by the U.S. Department of the Treasury to allow the estimation of a 30-year rate; 30-year maturities February 2006 forward.

[3/] Terms to maturity of l0 years or more.

[4/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Uilities Index from 1996- August 2000; a series of long-term utility bonds maintained by Foster Associates from September 2000 forward.

[5/] Monthly dividend yields of Canadian Utilities, Emera Inc., Enbridge Inc., Fortis Inc., and Transcanada Corp.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
www.ustreas.gov

# TREND IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

| | | Canada | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Government Securities | | | | | | | | | | | Moody's U.S. Utility Long-Term A-Rated Bonds | Exchange Rate (Cdn$/US$) |
| | | T-Bills | | 10 Year | | Long-Term | | Bonds Over 10 Years [3] | Inflation Indexed Bonds | A-Rated Utility Bonds [4] | Median Utility Dividend Yield [5] | A-Rated Utility/ Long Canada Bond Yield Spread | | |
| Year | | Canadian | U.S. [1] | Canadian | U.S. | Canadian | U.S. [2] | | | | | | | |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
| 2005 | Q1 | 2.47 | 2.67 | 4.27 | 4.33 | 4.72 | 4.70 | 4.69 | 2.05 | 5.78 | 3.58 | 1.06 | 5.72 | 0.82 |
| | Q2 | 2.46 | 3.01 | 3.93 | 4.05 | 4.39 | 4.36 | 4.35 | 1.86 | 5.47 | 3.38 | 1.09 | 5.43 | 0.81 |
| | Q3 | 2.73 | 3.50 | 3.88 | 4.21 | 4.20 | 4.39 | 4.19 | 1.75 | 5.20 | 2.92 | 0.99 | 5.49 | 0.84 |
| | Q4 | 3.25 | 4.00 | 4.07 | 4.49 | 4.19 | 4.63 | 4.21 | 1.59 | 5.25 | 3.04 | 1.06 | 5.82 | 0.85 |
| 2006 | Q1 | 3.70 | 4.57 | 4.18 | 4.65 | 4.23 | 4.70 | 4.25 | 1.53 | 5.32 | 3.28 | 1.09 | 5.92 | 0.87 |
| | Q2 | 4.17 | 4.84 | 4.51 | 5.11 | 4.54 | 5.19 | 4.57 | 1.81 | 5.65 | 3.39 | 1.10 | 6.41 | 0.90 |
| | Q3 | 4.14 | 5.00 | 4.14 | 4.79 | 4.21 | 4.91 | 4.23 | 1.67 | 5.34 | 3.18 | 1.12 | 6.09 | 0.89 |
| | Q4 | 4.16 | 5.04 | 4.00 | 4.59 | 4.07 | 4.70 | 4.08 | 1.68 | 5.13 | 2.92 | 1.06 | 5.82 | 0.87 |
| 2007 | Q1 | 4.17 | 5.11 | 4.10 | 4.68 | 4.17 | 4.82 | 4.18 | 1.77 | 5.23 | 3.19 | 1.06 | 5.92 | 0.86 |
| | Q2 | 4.29 | 4.82 | 4.39 | 4.85 | 4.35 | 4.98 | 4.38 | 1.94 | 5.49 | 3.34 | 1.14 | 6.08 | 0.92 |
| | Q3 | 4.17 | 4.26 | 4.43 | 4.64 | 4.45 | 4.86 | 4.46 | 2.09 | 5.75 | 3.36 | 1.30 | 6.19 | 0.97 |
| | Q4 | 3.90 | 3.48 | 4.09 | 4.16 | 4.21 | 4.53 | 4.21 | 2.01 | 5.61 | 3.13 | 1.39 | 6.05 | 1.02 |
| 2008 | Q1 | 2.76 | 1.73 | 3.65 | 3.55 | 4.07 | 4.35 | 4.03 | 1.80 | 5.65 | 3.31 | 1.58 | 6.16 | 0.99 |
| | Q2 | 2.60 | 1.74 | 3.68 | 3.94 | 4.10 | 4.58 | 4.07 | 1.60 | 5.84 | 3.63 | 1.74 | 6.30 | 0.99 |
| | Q3 | 2.23 | 1.44 | 3.66 | 3.89 | 4.11 | 4.44 | 4.13 | 1.78 | 6.21 | 3.66 | 2.10 | 6.58 | 0.95 |
| | Q4 | 1.45 | 0.19 | 3.26 | 3.06 | 3.88 | 3.50 | 3.91 | 2.42 | 7.47 | 3.87 | 3.60 | 7.13 | 0.82 |
| 2009 | Q1 | 0.61 | 0.24 | 2.99 | 2.87 | 3.68 | 3.62 | 3.65 | 2.13 | 7.06 | 4.38 | 3.38 | 6.44 | 0.80 |
| | Q2 | 0.21 | 0.16 | 3.28 | 3.39 | 3.90 | 4.24 | 3.86 | 1.97 | 6.27 | 4.37 | 2.37 | 6.35 | 0.87 |
| | Q3 | 0.22 | 0.16 | 3.38 | 3.41 | 3.89 | 4.17 | 3.94 | 1.76 | 5.49 | 4.14 | 1.60 | 5.54 | 0.92 |
| | Q4 | 0.21 | 0.06 | 3.42 | 3.49 | 3.95 | 4.35 | 3.96 | 1.57 | 5.56 | 3.91 | 1.62 | 5.65 | 0.94 |
| 2010 | Q1 | 0.20 | 0.12 | 3.43 | 3.69 | 4.01 | 4.59 | 3.94 | 1.54 | 5.45 | 3.91 | 1.44 | 5.80 | 0.96 |
| | Q2 | 0.46 | 0.17 | 3.36 | 3.32 | 3.80 | 4.22 | 3.73 | 1.45 | 5.37 | 4.09 | 1.57 | 5.46 | 0.96 |
| | Q3 | 0.74 | 0.15 | 2.88 | 2.65 | 3.49 | 3.73 | 3.42 | 1.35 | 5.00 | 3.71 | 1.51 | 4.96 | 0.96 |
| | Q4 | 0.97 | 0.14 | 2.99 | 2.91 | 3.48 | 4.15 | 3.42 | 1.11 | 4.98 | 3.42 | 1.50 | 5.31 | 0.99 |
| 2011 | Q1 | 0.95 | 0.13 | 3.31 | 3.44 | 3.73 | 4.53 | 3.68 | 1.25 | 5.18 | 3.42 | 1.46 | 5.56 | 1.02 |
| | Q2 | 0.96 | 0.04 | 3.13 | 3.18 | 3.58 | 4.33 | 3.50 | 1.00 | 5.07 | 3.56 | 1.49 | 5.37 | 1.04 |
| | Q3 | 0.88 | 0.05 | 2.48 | 2.32 | 3.05 | 3.54 | 2.96 | 0.83 | 4.65 | 3.58 | 1.60 | 4.74 | 1.01 |
| | Q4 | 0.86 | 0.01 | 2.13 | 2.05 | 2.70 | 3.04 | 2.61 | 0.58 | 4.37 | 3.46 | 1.67 | 4.35 | 0.99 |
| 2012 | Q1 | 0.91 | 0.07 | 1.99 | 2.01 | 2.59 | 3.12 | 2.48 | 0.44 | 4.10 | 3.62 | 1.51 | 4.35 | 1.00 |
| | Q2 | 0.95 | 0.09 | 1.84 | 1.74 | 2.41 | 2.85 | 2.31 | 0.45 | 4.08 | 3.62 | 1.67 | 4.17 | 0.99 |
| 2008 | Jan | 3.38 | 1.96 | 3.88 | 3.67 | 4.18 | 4.35 | 4.16 | 1.96 | 5.67 | 3.07 | 1.49 | 6.07 | 1.00 |
| | Feb | 3.04 | 1.85 | 3.64 | 3.53 | 4.09 | 4.41 | 4.04 | 1.85 | 5.66 | 3.44 | 1.57 | 6.22 | 1.02 |
| | Mar | 1.87 | 1.38 | 3.43 | 3.45 | 3.94 | 4.30 | 3.88 | 1.60 | 5.63 | 3.42 | 1.69 | 6.20 | 0.97 |
| | Apr | 2.68 | 1.43 | 3.58 | 3.77 | 4.08 | 4.49 | 4.02 | 1.72 | 5.78 | 3.60 | 1.70 | 6.22 | 0.99 |
| | May | 2.64 | 1.89 | 3.71 | 4.06 | 4.13 | 4.72 | 4.09 | 1.61 | 5.83 | 3.66 | 1.70 | 6.36 | 0.99 |
| | Jun | 2.48 | 1.90 | 3.74 | 3.99 | 4.08 | 4.53 | 4.10 | 1.47 | 5.89 | 3.65 | 1.81 | 6.32 | 0.98 |
| | Jul | 2.39 | 1.68 | 3.70 | 3.99 | 4.10 | 4.59 | 4.11 | 1.54 | 5.92 | 3.63 | 1.82 | 6.44 | 0.98 |
| | Aug | 2.40 | 1.72 | 3.53 | 3.83 | 4.01 | 4.43 | 4.02 | 1.57 | 6.09 | 3.58 | 2.08 | 6.32 | 0.94 |
| | Sep | 1.89 | 0.92 | 3.75 | 3.85 | 4.23 | 4.31 | 4.25 | 2.23 | 6.64 | 3.77 | 2.41 | 6.98 | 0.94 |
| | Oct | 1.85 | 0.46 | 3.76 | 4.01 | 4.28 | 4.35 | 4.33 | 2.51 | 7.61 | 3.80 | 3.33 | 8.01 | 0.82 |
| | Nov | 1.67 | 0.01 | 3.32 | 2.93 | 3.90 | 3.45 | 3.96 | 2.65 | 7.48 | 3.74 | 3.58 | 7.18 | 0.81 |
| | Dec | 0.83 | 0.11 | 2.69 | 2.25 | 3.45 | 2.69 | 3.45 | 2.10 | 7.33 | 4.07 | 3.88 | 6.20 | 0.82 |
| 2009 | Jan | 0.86 | 0.24 | 3.06 | 2.87 | 3.77 | 3.58 | 3.80 | 2.27 | 7.33 | 4.11 | 3.56 | 6.52 | 0.81 |
| | Feb | 0.59 | 0.26 | 3.12 | 3.02 | 3.70 | 3.71 | 3.70 | 2.32 | 7.07 | 4.33 | 3.37 | 6.38 | 0.79 |
| | Mar | 0.39 | 0.21 | 2.79 | 2.71 | 3.57 | 3.56 | 3.46 | 1.81 | 6.78 | 4.70 | 3.21 | 6.41 | 0.79 |
| | Apr | 0.20 | 0.14 | 3.09 | 3.16 | 3.84 | 4.05 | 3.74 | 2.05 | 6.71 | 4.70 | 2.87 | 6.55 | 0.84 |
| | May | 0.20 | 0.14 | 3.39 | 3.47 | 3.99 | 4.34 | 3.93 | 2.00 | 6.14 | 4.33 | 2.15 | 6.53 | 0.91 |
| | Jun | 0.24 | 0.19 | 3.36 | 3.53 | 3.86 | 4.32 | 3.91 | 1.86 | 5.94 | 4.09 | 2.08 | 5.96 | 0.86 |
| | Jul | 0.24 | 0.18 | 3.46 | 3.52 | 3.95 | 4.31 | 4.01 | 1.73 | 5.54 | 4.08 | 1.59 | 5.68 | 0.93 |
| | Aug | 0.20 | 0.15 | 3.37 | 3.40 | 3.89 | 4.18 | 3.94 | 1.81 | 5.45 | 4.18 | 1.56 | 5.54 | 0.91 |
| | Sep | 0.22 | 0.14 | 3.31 | 3.31 | 3.84 | 4.03 | 3.87 | 1.74 | 5.49 | 4.16 | 1.65 | 5.41 | 0.93 |
| | Oct | 0.22 | 0.05 | 3.42 | 3.41 | 3.92 | 4.23 | 3.95 | 1.60 | 5.49 | 4.11 | 1.57 | 5.55 | 0.93 |
| | Nov | 0.21 | 0.06 | 3.22 | 3.21 | 3.84 | 4.20 | 3.83 | 1.58 | 5.50 | 3.98 | 1.66 | 5.54 | 0.95 |
| | Dec | 0.19 | 0.06 | 3.61 | 3.85 | 4.08 | 4.63 | 4.09 | 1.53 | 5.69 | 3.63 | 1.61 | 5.86 | 0.96 |
| 2010 | Jan | 0.16 | 0.08 | 3.34 | 3.63 | 3.94 | 4.51 | 3.90 | 1.49 | 5.42 | 3.75 | 1.48 | 5.73 | 0.94 |
| | Feb | 0.16 | 0.13 | 3.39 | 3.61 | 4.02 | 4.55 | 3.94 | 1.58 | 5.49 | 4.11 | 1.47 | 5.77 | 0.95 |
| | Mar | 0.28 | 0.16 | 3.56 | 3.84 | 4.07 | 4.72 | 3.99 | 1.56 | 5.44 | 3.88 | 1.37 | 5.89 | 0.98 |
| | Apr | 0.39 | 0.16 | 3.65 | 3.69 | 4.01 | 4.53 | 3.94 | 1.49 | 5.40 | 3.99 | 1.39 | 5.60 | 0.99 |
| | May | 0.50 | 0.16 | 3.36 | 3.31 | 3.73 | 4.22 | 3.65 | 1.45 | 5.46 | 4.15 | 1.73 | 5.57 | 0.96 |
| | Jun | 0.50 | 0.18 | 3.08 | 2.97 | 3.65 | 3.91 | 3.59 | 1.42 | 5.24 | 4.12 | 1.59 | 5.21 | 0.94 |
| | Jul | 0.66 | 0.15 | 3.11 | 2.94 | 3.69 | 3.98 | 3.62 | 1.51 | 5.17 | 3.83 | 1.48 | 5.17 | 0.97 |
| | Aug | 0.70 | 0.14 | 2.78 | 2.47 | 3.44 | 3.52 | 3.36 | 1.34 | 5.01 | 3.80 | 1.57 | 4.78 | 0.94 |
| | Sep | 0.87 | 0.16 | 2.75 | 2.53 | 3.35 | 3.69 | 3.27 | 1.20 | 4.82 | 3.51 | 1.47 | 4.93 | 0.97 |
| | Oct | 0.92 | 0.12 | 2.80 | 2.63 | 3.44 | 3.99 | 3.32 | 1.09 | 4.89 | 3.46 | 1.45 | 5.21 | 0.98 |
| | Nov | 1.01 | 0.17 | 3.07 | 2.81 | 3.48 | 4.12 | 3.45 | 1.12 | 5.04 | 3.49 | 1.56 | 5.28 | 0.97 |
| | Dec | 0.97 | 0.12 | 3.11 | 3.30 | 3.52 | 4.34 | 3.48 | 1.11 | 5.00 | 3.30 | 1.48 | 5.45 | 1.01 |
| 2011 | Jan | 0.96 | 0.15 | 3.27 | 3.42 | 3.73 | 4.58 | 3.68 | 1.38 | 5.18 | 3.25 | 1.45 | 5.61 | 1.00 |
| | Feb | 0.96 | 0.15 | 3.30 | 3.42 | 3.70 | 4.49 | 3.65 | 1.22 | 5.14 | 3.52 | 1.44 | 5.51 | 1.03 |
| | Mar | 0.93 | 0.09 | 3.35 | 3.47 | 3.75 | 4.51 | 3.70 | 1.15 | 5.23 | 3.50 | 1.48 | 5.57 | 1.03 |
| | Apr | 0.98 | 0.04 | 3.20 | 3.32 | 3.69 | 4.40 | 3.62 | 1.00 | 5.19 | 3.57 | 1.50 | 5.46 | 1.05 |
| | May | 0.96 | 0.06 | 3.07 | 3.05 | 3.49 | 4.22 | 3.38 | 0.98 | 4.97 | 3.51 | 1.48 | 5.23 | 1.03 |
| | Jun | 0.93 | 0.03 | 3.11 | 3.18 | 3.55 | 4.38 | 3.49 | 1.03 | 5.04 | 3.59 | 1.49 | 5.41 | 1.04 |
| | Jul | 0.91 | 0.10 | 2.79 | 2.82 | 3.29 | 4.12 | 3.21 | 0.79 | 4.73 | 3.66 | 1.44 | 5.09 | 1.05 |
| | Aug | 0.93 | 0.02 | 2.49 | 2.23 | 3.10 | 3.60 | 3.00 | 0.88 | 4.74 | 3.55 | 1.64 | 4.74 | 1.02 |
| | Sep | 0.80 | 0.02 | 2.15 | 1.92 | 2.77 | 2.90 | 2.68 | 0.82 | 4.49 | 3.52 | 1.72 | 4.38 | 0.96 |
| | Oct | 0.89 | 0.01 | 2.29 | 2.17 | 2.92 | 3.16 | 2.81 | 0.67 | 4.54 | 3.44 | 1.62 | 4.42 | 1.01 |
| | Nov | 0.86 | 0.01 | 2.15 | 2.08 | 2.69 | 3.06 | 2.61 | 0.61 | 4.41 | 3.46 | 1.72 | 4.38 | 0.98 |
| | Dec | 0.82 | 0.02 | 1.94 | 1.89 | 2.49 | 2.89 | 2.41 | 0.45 | 4.17 | 3.48 | 1.68 | 4.24 | 0.98 |
| 2012 | Jan | 0.88 | 0.06 | 1.89 | 1.83 | 2.50 | 2.94 | 2.40 | 0.38 | 4.05 | 3.47 | 1.55 | 4.22 | 0.99 |
| | Feb | 0.93 | 0.08 | 1.98 | 1.98 | 2.60 | 3.08 | 2.48 | 0.44 | 4.10 | 3.68 | 1.50 | 4.30 | 1.01 |
| | Mar | 0.91 | 0.07 | 2.11 | 2.23 | 2.66 | 3.35 | 2.55 | 0.51 | 4.14 | 3.72 | 1.48 | 4.54 | 1.00 |
| | Apr | 1.05 | 0.10 | 2.04 | 1.95 | 2.61 | 3.12 | 2.51 | 0.57 | 4.22 | 3.50 | 1.61 | 4.33 | 1.01 |
| | May | 0.93 | 0.07 | 1.74 | 1.59 | 2.29 | 2.67 | 2.16 | 0.34 | 4.00 | 3.65 | 1.71 | 4.04 | 0.97 |
| | Jun | 0.87 | 0.09 | 1.74 | 1.67 | 2.33 | 2.76 | 2.25 | 0.44 | 4.03 | 3.72 | 1.70 | 4.13 | 0.98 |

[1] Rates on new issues.
[2] Theoretical 30-year yield, 2005 to January 2006. 30-year maturities February 2006 forward.
[3] Terms to maturity of 10 years or more.
[4] Series of long-term utility bonds maintained by Foster Associates.
[5] Monthly dividend yields of Canadian Utilities, Emera Inc., Enbridge Inc., Fortis Inc., and Transcanada Corp.
Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
RBC Capital Markets, www.ustreas.gov

**EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES**
**(Percentages)**

| | Decision Date | Regulator | Order/ File Number | Debt | Preferred Stock | Common Stock Equity | Equity Return | Forecast 30-Year Bond Yield | |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | |
| **Gas Distributors** | | | | | | | | | |
| AltaGas Utilities | 12/11 | AUC | 2011-474 | 57.00 | 0.00 | 43.00 | 8.75 | 3.60 | |
| ATCO Gas | 12/11 | AUC | 2011-474 | 53.09 | 7.91 | 39.00 | 8.75 | 3.60 | |
| Enbridge Gas Distribution Inc | 1/04; 7/07; 2/08 | OEB | RP-2002-0158; EB-2006-0034; EB-2007-0615 | 61.33 | 2.67 | 36.00 | 8.39 | 4.23 | |
| FortisBC Energy Inc. | 12/09 | BCUC | G-158-09 | 60.00 | 0.00 | 40.00 | 9.50 | 4.30 | |
| FortisBC Energy (Vancouver Island) | 12/09 | BCUC | G-14-06; G-158-09 | 60.00 | 0.00 | 40.00 | 10.00 | 4.30 | |
| FortisBC Energy Inc (Whistler) | 4/09; 12/09 | BCUC | G-35-09; G-158-09 | 60.00 | 0.00 | 40.00 | 10.00 | 4.30 | |
| Gazifère | 11/10;12/11 | Régie | D-2010-147;D-2011-189 | 60.00 | 0.00 | 40.00 | 8.29 | 3.10 | |
| Gaz Métro | 11/11 | Régie | D-2011-182 | 54.00 | 7.50 | 38.50 | 8.90 | 4.00 | |
| Pacific Northern Gas-West | 12/09; 5/10 | BCUC | G-158-09; G-84-10 | 51.15 | 3.85 | 45.00 | 10.15 | 4.30 | |
| Pacific Northern Gas-Fort St. John/Dawson Creek | 12/09; 5/10 | BCUC | G-158-09; G-84-10 | 60.00 | 0.00 | 40.00 | 9.90 | 4.30 | |
| Pacific Northern Gas-Tumbler Ridge | 12/09; 5/10 | BCUC | G-158-09; G-84-10 | 60.00 | 0.00 | 40.00 | 10.15 | 4.30 | |
| Union Gas | 1/04; 5/06; 1/08 | OEB | RP-2002-0158; EB-2006-0520; EB-2007-0606 | 60.60 | 3.40 | 36.00 | 8.54 | 4.23 | |
| **Electric Utilities** | | | | | | | | | |
| AltaLink | 12/11 | AUC | 2011-474 | 63.00 | 0.00 | 37.00 | 8.75 | 3.60 | |
| ATCO Electric | | | | | | | | | |
| Transmission | 12/11 | AUC | 2011-474 | 52.81 | 10.19 | 37.00 | 8.75 | 3.60 | |
| Distribution | 12/11 | AUC | 2011-474 | 50.95 | 10.05 | 39.00 | 8.75 | 3.60 | |
| ENMAX | | | | | | | | | |
| Transmission | 12/11 | AUC | 2011-474 | 63.00 | 0.00 | 37.00 | 8.75 | 3.60 | |
| Distribution | 12/11 | AUC | 2011-474 | 59.00 | 0.00 | 41.00 | 8.75 | 3.60 | |
| EPCOR | | | | | | | | | |
| Transmission | 12/11 | AUC | 2011-474 | 63.00 | 0.00 | 37.00 | 8.75 | 3.60 | |
| Distribution | 12/11 | AUC | 2011-474 | 59.00 | 0.00 | 41.00 | 8.75 | 3.60 | |
| FortisAlberta Inc. | 12/11 | AUC | 2011-474 | 59.00 | 0.00 | 41.00 | 8.75 | 3.60 | |
| FortisBC Inc. | 5/05; 12/09 | BCUC | G-52-05; G-158-09 | 60.00 | 0.00 | 40.00 | 9.90 | 4.30 | |
| Hydro One Transmission | 12/10; 3/12 | OEB | EB-2010-0002; Letter Cost of Capital Parameters | 60.00 | 0.00 | 40.00 | 9.12 | 2.93 | |
| Maritime Electric | 7/10 | IRAC | UE-10-03 | 59.50 | 0.00 | 40.50 | 9.75 | n/a | 1/ |
| Newfoundland Power | 12/09; 12/10 | NLPub | P.U. 46 (2009); P.U. 32 (2010) | 54.27 | 1.04 | 44.69 | 8.38 | 3.72 | |
| Nova Scotia Power | 11/11 | NSUARB | 2011 NSUARB 184 | 53.30 | 9.20 | 37.50 | 9.20 | n/a | |
| Ontario Electricity Distributors | 12/09; 3/12 | OEB | EB-2009-0084; Letter Cost of Capital Parameters | 60.00 | 0.00 | 40.00 | 9.12 | 2.93 | |
| Ontario Power Generation | 3/11 | OEB | EB-2010-0008 | 53.00 | 0.00 | 47.00 | 9.55 | 3.85 | |
| **Gas Pipelines** | | | | | | | | | |
| Foothills Pipe Lines Ltd. | 6/10 | NEB | TG-03-2010 | 60.00 | 0.00 | 40.00 | 9.70 | n/a | |
| Nova Gas Transmission Ltd. | 9/10 | NEB | TG-05-2010 | 60.00 | 0.00 | 40.00 | 9.70 | n/a | |
| TransCanada PipeLines | 5/07; 11/10 | NEB | RH-2-94;TG-06-2007; NEB Letter 11-10 | 60.00 | 0.00 | 40.00 | 9.70 | n/a | |
| Trans Québec & Maritimes Pipeline | 3/09; 11/10 | NEB | RH-1-2008; TG-07-2010 | 60.00 | 0.00 | 40.00 | 8.08 | 3.72 | |
| Westcoast Energy | 1/11 | NEB | TG-01-2011 | 60.00 | 0.00 | 40.00 | 9.70 | n/a | 2/ |

1/ In 2010, the Electric Power Amendment Act reduced electricity rates and froze them until March 2013.
2/ Settlement for 2010-2012 does not specify return on rate base; AFUDC rate, income taxes and capital variances based on a 9.7% ROE, 60%/40% debt/equity capital structure and TQM's embedded cost of debt.
Source: Regulatory Decisions.

**RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES**

| | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas Distributors** | | | | | | | | | | | | | | | | | | | | | | | |
| AltaGas Utilities | NA | 13.50 | 13.25 | NA | NA | 12.00 | 11.75 | 11.75 | 11.75 | 11.75 | 9.90 | 9.70 | 9.70 | 9.50 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 | 9.00 | 9.00 | 8.75 | 8.75 |
| ATCO Gas | 13.25 | 13.25 | 12.25 | 12.25 | NA | NA | NA | 10.50 | 9.38 | NA | NA | 9.75 | 9.75 | 9.50 | 9.50 | 9.50 | 8.93 | 8.51 | 8.75 | 9.00 | 9.00 | 8.75 | 8.75 |
| Enbridge Gas Distribution | 13.25 | 13.13 | 13.13 | 12.30 | 11.60 | 11.65 | 11.88 | 11.50 | 10.30 | 9.51 | 9.73 | 9.54 | 9.66 | 9.69 | NA | 9.57 | 8.74 | 8.39 | 8.39 | 8.39 | 8.39 | 8.39 | 8.39 |
| FortisBC Energy [1/] | NA | NA | 12.25 | NA | 10.65 | 12.00 | 11.00 | 10.25 | 10.00 | 9.25 | 9.50 | 9.25 | 9.13 | 9.42 | 9.15 | 9.03 | 8.80 | 8.37 | 8.62 | 8.47 | 9.50 | 9.50 | 9.50 |
| Gaz Métro | 14.25 | 14.25 | 14.00 | 12.50 | 12.00 | 12.00 | 12.00 | 11.50 | 10.75 | 9.64 | 9.72 | 9.60 | 9.67 | 9.89 | 9.45 | 9.69 | 8.95 | 8.73 | 9.05 | 8.76 | 9.20 | 9.09 | 8.90 |
| Pacific Northern Gas [1/] | 15.00 | 14.00 | 13.25 | NA | 11.50 | 12.75 | 11.75 | 11.00 | 10.75 | 10.00 | 10.25 | 10.00 | 9.88 | 10.17 | 9.80 | 9.68 | 9.45 | 9.02 | 9.27 | 9.12 | 10.15 | 10.15 | 10.15 |
| Union Gas | 13.75 | 13.50 | 13.50 | 13.00 | 12.50 | 11.75 | 11.75 | 11.00 | 10.44 | 9.61 | 9.95 | 9.95 | 9.95 | 9.95 | 9.62 | 9.62 | 8.89 | 8.54 | 8.54 | 8.54 | 8.54 | 8.54 | 8.54 |
| **Mean of Gas Distributors** | **13.90** | **13.60** | **13.09** | **12.51** | **11.65** | **12.03** | **11.69** | **11.07** | **10.48** | **9.96** | **9.84** | **9.68** | **9.68** | **9.73** | **9.52** | **9.51** | **8.96** | **8.58** | **8.77** | **8.75** | **9.11** | **9.02** | **9.00** |
| **Electric Utilities** | | | | | | | | | | | | | | | | | | | | | | | |
| AltaLink | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.40 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 | 9.00 | 9.00 | 8.75 | 8.75 |
| ATCO Electric | 13.50 | 13.50 | 13.25 | 11.88 | NA | NA | 11.25 | 2/ | 2/ | 2/ | 2/ | 2/ | 2/ | 9.40 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 | 9.00 | 9.00 | 8.75 | 8.75 |
| FortisAlberta Inc. | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.50 | 9.50 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 | 9.00 | 9.00 | 8.75 | 8.75 |
| FortisBC Inc. [1/] | 13.50 | NA | 11.75 | 11.50 | 11.00 | 12.25 | 11.25 | 10.50 | 10.25 | 9.50 | 10.00 | 9.75 | 9.53 | 9.82 | 9.55 | 9.43 | 9.20 | 8.77 | 9.02 | 8.87 | 9.90 | 9.90 | 9.90 |
| Newfoundland Power | 13.95 | 13.25 | NA | NA | NA | NA | 11.00 | NA | 9.25 | 9.25 | 9.59 | 9.59 | 9.05 | 9.75 | 9.75 | 9.24 | 9.24 | 8.60 | 8.95 | 8.95 | 9.00 | 8.38 | 8.80 |
| Nova Scotia Power | NA | NA | NA | 11.75 | NA | NA | 10.75 | NA | NA | NA | NA | NA | 10.15 | NA | NA | 9.55 | 9.55 | 9.55 | NA | 9.35 | NA | NA | 9.20 |
| Ontario Electricity Distributors | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.35 | 9.88 | 9.88 | 9.88 | 9.88 | 9.88 | 9.88 | 9.00 | 9.00 | 8.57 | 8.01 | 9.85 | 9.58 | 9.42 |
| TransAlta Utilities | 13.50 | 13.50 | 13.25 | 11.88 | NA | 12.25 | 11.25 | 2/ | 3/ | 9.25 | 9.25 | NA | 9.40 | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| **Mean of Electric Utilities** | **13.61** | **13.42** | **12.75** | **11.75** | **11.00** | **12.25** | **11.10** | **10.50** | **9.75** | **9.34** | **9.68** | **9.74** | **9.59** | **9.63** | **9.66** | **9.51** | **9.11** | **8.78** | **8.80** | **8.88** | **9.29** | **9.02** | **9.08** |
| **Gas Pipelines (NEB)** | | | | | | | | | | | | | | | | | | | | | | | |
| TransCanada PipeLines | 13.25 | 13.50 | 13.25 | 12.25 | 11.25 | 12.25 | 11.25 | 10.67 | 10.21 | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 | 9.46 | 8.88 | 8.46 | 8.72 | 8.57 | 8.52 | 8.08 | NA[4/] |
| Westcoast Energy | 13.25 | 13.75 | 12.50 | 12.25 | 11.50 | 12.25 | 11.25 | 10.67 | 10.21 | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 | 9.46 | 8.88 | 8.46 | 8.72 | 8.57 | 8.52 | 9.70 | 9.70 |
| **Mean of Gas Pipelines** | **13.25** | **13.63** | **12.88** | **12.25** | **11.38** | **12.25** | **11.25** | **10.67** | **10.21** | **9.58** | **9.90** | **9.61** | **9.53** | **9.79** | **9.56** | **9.46** | **8.88** | **8.46** | **8.72** | **8.57** | **8.52** | **8.89** | **9.70** |
| **Mean of All Companies** | **13.68** | **13.56** | **12.97** | **12.16** | **11.50** | **12.12** | **11.39** | **10.93** | **10.30** | **9.69** | **9.80** | **9.69** | **9.62** | **9.70** | **9.59** | **9.51** | **9.01** | **8.65** | **8.77** | **8.79** | **9.10** | **9.00** | **9.08** |

1/ Allowed ROE for 2009 for first six months

2/ Negotiated settlement, details not available.

3/ Negotiated settlement, implicit ROE made public is 10.5%.

4/ Rate case ongoing for 2012.

Note: The allowed ROEs for ENMAX Distribution, EPCOR Distribution and EPCOR Transmission have been identical to those of the other Alberta utilities since 2004 (ENMAX Transmission since 2006).
Source: Regulatory Decisions

## DEBT RATINGS OF CANADIAN UTILITIES

| Company | Ratings: DBRS Issuer Rating (1) | DBRS Debt Rating (2) | Moody's Issuer Rating (3) | Moody's Debt Rating (4) | S&P Corporate Credit Rating (5) | S&P Debt Rating (6) | S&P Business Risk Profile (7) |
|---|---|---|---|---|---|---|---|
| **Gas Distributors** | | | | | | | |
| Enbridge Gas Distribution | | A (Unsecured) | | | A- | A- (Senior Unsecured) | Excellent |
| FortisBC Energy Inc. | | A (Unsecured) | | A3 (Senior Unsecured)<br>A1 (Senior Secured) | | 1/ | |
| FortisBC Energy Inc. (Vancouver Island) | | BBB(high) (Debentures) | | A3 (Senior Unsecured) | | | |
| Gaz Métro Inc. | | A (First Mortgage) | | | A- | A (Senior Secured) | Excellent |
| Pacific Northern Gas | | 2/ | | | | | |
| Union Gas Limited | | A (Unsecured) | | | BBB+ | BBB+ (Senior Unsecured) | Strong |
| **Median** | | **A** | | **A3** | **A-** | **A-** | **Excellent** |
| **Electric Utilities** | | | | | | | |
| AltaLink L.P. | | A (Senior Secured) | | | A- | A- (Senior Secured) | Excellent |
| CU Inc. | | A(high) (Unsecured) | | | A | A (Senior Unsecured) | Excellent |
| Enersource | A | A (Senior Unsecured) | | | | | |
| ENMAX Corp. | | A(low) (Unsecured) | | | BBB+ | BBB+ (Senior Unsecured) | Strong |
| ENTEGRUS Inc. 3/ | | | | | A | | Excellent |
| EPCOR Utilities Inc. | | A(low) (Senior Unsecured) | | | BBB+ | BBB+ (Senior Unsecured) | Strong |
| FortisAlberta Inc. | | A(low) (Senior Unsecured) | | Baa1 (Senior Unsecured) | A- | A- (Senior Unsecured) | Excellent |
| FortisBC Inc. | | A(low) (Unsecured) | | Baa1 (Senior Unsecured) | | | |
| Guelph Hydro Electric Systems | | | | | A | A (Senior Unsecured) | Excellent |
| Hamilton Utilities | | | | | A | A (Senior Unsecured) | Excellent |
| Hydro One Inc. | | A(high) (Senior Unsecured) | | A1 (Senior Unsecured) 4/ | A+ 4/ | A+ (Senior Unsecured) 4/ | Excellent |
| Hydro Ottawa Holding Inc. | | A (Senior Unsecured) | | | A | A (Senior Unsecured) | Excellent |
| London Hydro | | | | | A | | Excellent |
| Maritime Electric | | | | | BBB+ | A- (Senior Secured) | Strong |
| Newfoundland Power | | A (First Mortgage) | Baa1 | A2 (First Mortgage) | | | |
| Nova Scotia Power | | A(low) (Unsecured) | 5/ | 5/ | BBB+ | BBB+ (Senior Unsecured) | Strong |
| Ontario Power Generation | | A(low) (Unsecured) | | | A- | | Strong |
| Toronto Hydro | | A(high) (Senior Unsecured) | | | A | A (Senior Unsecured) | Excellent |
| Veridian Corp. | A | | | | | | |
| **Median** | | **A** | | **A3** | **A** | **A/A-** | **Excellent** |
| **Pipelines** | | | | | | | |
| Enbridge Pipelines Inc. | | A (Unsecured) | | | A- | A- (Senior Unsecured) | Excellent |
| NOVA Gas Transmission Ltd. | | A (Unsecured) | | A3 (Senior Unsecured) | A- | A- (Senior Unsecured) | |
| Trans Québec & Maritimes Pipeline | | A(low) (Senior Unsecured) | | | BBB+ | BBB+ (Senior Unsecured) | Strong |
| TransCanada PipeLines Ltd. | | A (Unsecured) | A3 | A3 (Senior Unsecured) | A- | A- (Senior Unsecured) | Excellent |
| Westcoast Energy Inc. | | A(low) (Unsecured) | | | BBB+ | BBB+ (Senior Unsecured) | Strong |
| **Median** | | **A** | | **A3** | **A-** | **A-** | **Excellent/Strong** |
| **Medians** | | | | | | | |
| **All Companies** | | **A** | | **A3** | **A-** | **A-** | **Excellent** |
| **All Investor-Owned Companies** | | **A** | | **A3** | **A-** | **A-** | **Excellent** |
| **All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI** | | **A** | | **Baa1** | **A-** | **A-** | **Excellent** |

1/ S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.
2/ DBRS rating discontinued March 12, 2012. Previously BBB(low) for Senior Secured.
3/ Previously Chatham-Kent Energy Inc.
4/ Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.
5/ Ratings withdrawn at request of company March 2010; unsecured debt previously rated Baa1.

## TOTAL CAPITAL STRUCTURE RATIOS OF CANADIAN UTILITIES WITH RATED DEBT
## (2011)

| Company | Total Debt [2/] | Preferred Stock [3/] | Common Stock Equity [4/] |
|---|---|---|---|
| | (1) | (2) | (3) |
| **Gas Distributors [1/]** | | | |
| Enbridge Gas Distribution | 57.3% | 2.1% | 40.5% |
| FortisBC Energy Inc. | 59.7% | 0.0% | 40.3% |
| Gaz Métro L.P. | 60.0% | 0.0% | 40.0% |
| Pacific Northern Gas | 48.0% | 2.6% | 49.3% |
| Union Gas Limited | 61.5% | 2.5% | 36.0% |
| **Median** | **59.7%** | **2.1%** | **40.3%** |
| **Electric Utilities** | | | |
| AltaLink L.P. | 56.7% | 0.0% | 43.3% |
| CU Inc. | 56.0% | 6.9% | 37.2% |
| Enersource [5/] | 55.0% | 0.0% | 45.0% |
| ENMAX Corp. | 45.6% | 0.0% | 54.4% |
| EPCOR Utilities Inc. | 42.0% | 0.0% | 58.0% |
| FortisAlberta Inc. | 57.4% | 0.0% | 42.6% |
| FortisBC Inc. | 58.4% | 0.0% | 41.6% |
| Hamilton Utilities | 37.4% | 0.0% | 62.6% |
| Hydro One Inc. | 55.5% | 2.2% | 42.3% |
| Hydro Ottawa Holding Inc. [5/] | 42.3% | 0.0% | 57.7% |
| London Hydro | 43.2% | 0.0% | 56.8% |
| Maritime Electric | 56.5% | 0.0% | 43.5% |
| Newfoundland Power | 54.7% | 1.0% | 44.2% |
| Nova Scotia Power [6/] | 57.9% | 3.8% | 38.3% |
| Toronto Hydro | 57.0% | 0.0% | 43.0% |
| Veridian Corp. [5/] | 44.1% | 0.0% | 55.9% |
| **Median** | **55.2%** | **0.0%** | **43.9%** |
| **Pipelines** | | | |
| Enbridge Pipelines Inc. | 52.9% | 0.0% | 47.1% |
| Nova Gas Transmission Ltd. | 65.4% | 0.0% | 34.6% |
| Trans Québec & Maritimes Pipeline | 59.9% | 0.0% | 40.1% |
| TransCanada PipeLines Ltd. | 53.3% | 0.9% | 45.8% |
| Westcoast Energy Inc. | 59.0% | 3.6% | 37.4% |
| **Median** | **59.0%** | **0.0%** | **40.1%** |
| **Medians** | | | |
| **All Companies** | **56.2%** | **0.0%** | **43.1%** |
| **All Investor-Owned Companies** | **57.4%** | **0.0%** | **40.5%** |
| **All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI** | **57.4%** | **1.0%** | **40.5%** |

[1/] The average of the four quarters ending December 2011 for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.

[2/] Includes preferred securities classified as debt.

[3/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

[4/] Includes non-controlling interests in common shares of subsidiary companies.

[5/] 2010 capital structure.

[6/] Common equity ratio excludes Accumulated Other Comprehensive Income.

Notes:

Financial statements for FortisBC Energy (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

**TOTAL CAPITAL STRUCTURE RATIOS
OF INVESTOR-OWNED CANADIAN UTILITIES WITH RATED DEBT
(Short-Term and Long-Term Debt Separated)**

| Company | 2008 Long-Term Debt [2] | 2008 Short-Term Debt | 2008 Preferred Stock [3] | 2008 Common Stock Equity [4] | 2009 Long-Term Debt [2] | 2009 Short-Term Debt | 2009 Preferred Stock [3] | 2009 Common Stock Equity [4] |
|---|---|---|---|---|---|---|---|---|
| **Gas Distributors [1]** | | | | | | | | |
| Enbridge Gas Distribution | 49.0% | 9.6% | 2.1% | 39.2% | 48.7% | 6.6% | 2.3% | 42.4% |
| FortisBC Energy Inc. | 56.1% | 9.5% | 0.0% | 34.5% | 59.4% | 4.8% | 0.0% | 35.8% |
| Gaz Métro L.P. | 62.4% | 1.4% | 0.0% | 36.2% | 62.0% | 1.0% | 0.0% | 37.0% |
| Pacific Northern Gas | 44.9% | 2.4% | 3.0% | 49.7% | 45.9% | 0.4% | 3.0% | 50.8% |
| Union Gas Limited | 56.6% | 4.0% | 2.9% | 36.5% | 59.7% | 0.0% | 0.0% | 40.3% |
| **Median** | **56.1%** | 4.0% | 2.1% | 36.5% | 59.4% | 1.0% | 0.0% | 40.3% |
| **Electric Utilities** | | | | | | | | |
| AltaLink L.P. | 61.7% | 0.0% | 0.0% | 38.3% | 54.1% | 0.0% | 0.0% | 45.9% |
| CU Inc. | 56.4% | 0.3% | 5.1% | 38.2% | 53.6% | 0.1% | 7.7% | 38.6% |
| FortisAlberta Inc. | 60.0% | 0.5% | 0.0% | 39.4% | 56.4% | 0.9% | 0.0% | 42.7% |
| FortisBC Inc. | 59.1% | 0.0% | 0.0% | 40.9% | 59.2% | 0.0% | 0.0% | 40.8% |
| Maritime Electric | 53.6% | 6.2% | 0.0% | 40.2% | 52.4% | 6.1% | 0.0% | 41.5% |
| Newfoundland Power | 53.4% | 0.0% | 1.1% | 45.5% | 55.1% | 0.0% | 1.0% | 43.8% |
| Nova Scotia Power [5] | 54.3% | 0.8% | 4.7% | 40.1% | 51.3% | 6.8% | 4.6% | 37.2% |
| **Median** | 56.4% | 0.3% | 0.0% | 40.1% | 54.1% | 0.1% | 0.0% | 41.5% |
| **Pipelines** | | | | | | | | |
| Enbridge Pipelines Inc. | 52.7% | 7.0% | 0.0% | 40.4% | 44.4% | 12.7% | 0.0% | 42.9% |
| Nova Gas Transmission Ltd. | 61.4% | 0.6% | 0.0% | 38.0% | 63.8% | 0.5% | 0.0% | 35.7% |
| Trans Québec & Maritimes Pipeline | 69.9% | 0.0% | 0.0% | 30.1% | 62.9% | 0.0% | 0.0% | 37.1% |
| TransCanada PipeLines Ltd. | 54.4% | 5.0% | 1.1% | 39.5% | 51.8% | 4.7% | 1.1% | 42.4% |
| Westcoast Energy Inc. | 51.3% | 3.6% | 4.8% | 40.3% | 57.1% | 1.5% | 5.4% | 36.0% |
| **Pipelines** | 54.4% | 3.6% | 0.0% | 39.5% | 57.1% | 1.5% | 0.0% | 37.1% |
| **Median** | | | | | | | | |
| **All Companies** | 56.1% | 1.4% | 0.0% | 39.4% | 55.1% | 0.9% | 0.0% | 40.8% |
| **All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI** | 56.6% | 0.5% | 1.1% | 39.2% | 55.1% | 0.1% | 0.0% | 40.8% |

| Company | 2010 Long-Term Debt [2] | 2010 Short-Term Debt | 2010 Preferred Stock [3] | 2010 Common Stock Equity [4] | 2011 Long-Term Debt [2] | 2011 Short-Term Debt | 2011 Preferred Stock [3] | 2011 Common Stock Equity [4] |
|---|---|---|---|---|---|---|---|---|
| **Gas Distributors [1]** | | | | | | | | |
| Enbridge Gas Distribution | 49.7% | 6.7% | 2.2% | 41.3% | 50.3% | 7.0% | 2.1% | 40.5% |
| FortisBC Energy Inc. | 56.2% | 3.8% | 0.0% | 40.0% | 56.6% | 3.1% | 0.0% | 40.3% |
| Gaz Métro L.P. | 61.7% | 1.7% | 0.0% | 36.7% | 59.0% | 1.0% | 0.0% | 40.0% |
| Pacific Northern Gas | 47.3% | 1.6% | 2.7% | 48.4% | 46.2% | 1.8% | 2.6% | 49.3% |
| Union Gas Limited | 55.4% | 4.7% | 2.5% | 37.4% | 57.0% | 4.5% | 2.5% | 36.0% |
| **Median** | 55.4% | 3.8% | 2.2% | 40.0% | 56.6% | 3.1% | 2.1% | 40.3% |
| **Electric Utilities** | | | | | | | | |
| AltaLink L.P. | 56.0% | 0.0% | 0.0% | 44.0% | 52.3% | 4.5% | 0.0% | 43.3% |
| CU Inc. | 52.4% | 1.0% | 8.3% | 38.3% | 55.6% | 0.4% | 6.9% | 37.2% |
| FortisAlberta Inc. | 56.8% | 0.5% | 0.0% | 42.7% | 57.1% | 0.3% | 0.0% | 42.6% |
| FortisBC Inc. | 59.5% | 0.0% | 0.0% | 40.5% | 58.4% | 0.0% | 0.0% | 41.6% |
| Maritime Electric | 47.1% | 9.6% | 0.0% | 43.3% | 55.6% | 0.9% | 0.0% | 43.5% |
| Newfoundland Power | 53.7% | 0.0% | 1.0% | 45.2% | 54.7% | 0.0% | 1.0% | 44.2% |
| Nova Scotia Power [5] | 58.1% | 1.5% | 4.1% | 36.4% | 56.1% | 1.8% | 3.8% | 38.3% |
| **Median** | 56.0% | 0.5% | 0.0% | 42.7% | 55.6% | 0.4% | 0.0% | 42.6% |
| **Pipelines** | | | | | | | | |
| Enbridge Pipelines Inc. | 46.7% | 7.7% | 0.0% | 45.6% | 47.0% | 4.8% | 0.0% | 48.2% |
| Nova Gas Transmission Ltd. | 55.8% | 7.2% | 0.0% | 37.1% | 61.7% | 3.7% | 0.0% | 34.6% |
| Trans Québec & Maritimes Pipeline | 60.0% | 0.0% | 0.0% | 40.0% | 59.9% | 0.0% | 0.0% | 40.1% |
| TransCanada PipeLines Ltd. | 51.5% | 5.5% | 1.0% | 42.0% | 47.7% | 4.4% | 0.9% | 47.0% |
| Westcoast Energy Inc. | 57.6% | 0.4% | 5.2% | 36.9% | 55.9% | 2.9% | 3.6% | 37.6% |
| **Median** | 55.8% | 5.5% | 0.0% | 40.0% | 55.9% | 3.7% | 0.0% | 40.1% |
| **Medians** | | | | | | | | |
| **All Companies** | 55.8% | 1.6% | 0.0% | 40.5% | 55.9% | 1.8% | 0.0% | 40.5% |
| **All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI** | 56.0% | 1.0% | 1.0% | 40.5% | 56.1% | 1.0% | 1.0% | 40.5% |

[1] The average of the four quarters ending December for gas distributors was used to better measure
[2] Includes preferred securities classified as debt.
[3] Includes preferred securities classified as equity and non-controlling interests in subsidiary
[4] Includes non-controlling interests in common shares of subsidiary companies.
[5] 2011 Common equity ratio excludes Accumulated Other Comprehensive Income.
Notes:
FortisBC Energy (Vancouver Island) excluded as financial statements not publicly available.
Source: Reports to Shareholders

## CAPITAL STRUCTURE RATIOS OF SAMPLE OF U.S. UTILITIES
### (Four Quarters Ending December 2011)

| Company | Total Debt [1/] (1) | Preferred Stock [2/] (2) | Common Stock Equity [3/] (3) |
|---|---|---|---|
| AGL Resources Inc. | 56.6 | 0.0 | 43.4 |
| Alliant Energy Corp. | 47.3 | 2.6 | 50.1 |
| Atmos Energy Corp. | 50.3 | 0.0 | 49.7 |
| Consolidated Edison | 48.3 | 1.0 | 50.8 |
| Integrys Energy Group Inc. | 43.9 | 0.9 | 55.2 |
| Northwest Natural Gas | 53.0 | 0.0 | 47.0 |
| Piedmont Natural Gas [4/] | 48.6 | 0.0 | 51.4 |
| Southern Company | 53.9 | 1.8 | 44.3 |
| Vectren Corp. | 54.8 | 0.0 | 45.2 |
| WGL Holdings Inc. | 36.5 | 1.4 | 62.1 |
| Wisconsin Energy Corp. | 51.6 | 0.6 | 47.8 |
| Xcel Energy Inc. | 54.3 | 0.4 | 45.3 |
| **Median** | **51.0** | **0.5** | **48.7** |

[1/] Includes preferred securities classified as debt.

[2/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

[3/] Includes non-controlling interests in common shares of subsidiary companies.

[4/] Trailing four quarters ending October 31, 2011.

Source: Reports to Shareholders.

## CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

| Company | EBIT Coverage 2008 | EBIT Coverage 2009 | EBIT Coverage 2010 | EBIT Coverage 3 Year Average | | FFO Interest Coverage 2008 | FFO Interest Coverage 2009 | FFO Interest Coverage 2010 | FFO Interest Coverage 3 Year Average | | FFO To Debt 2008 | FFO To Debt 2009 | FFO To Debt 2010 | FFO To Debt 3 Year Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas Distributors** | | | | | | | | | | | | | | | |
| Enbridge Gas Distribution | 2.30 | 2.40 | 2.30 | 2.33 | | 3.30 | 3.50 | 3.40 | 3.40 | | 16.30 | 18.10 | 16.30 | 16.90 | |
| FortisBC Energy Inc. | 1.90 | 1.90 | 2.10 | 1.97 | 1/ | 2.50 | 2.60 | 2.70 | 2.60 | 2/ | 9.80 | 10.20 | 10.60 | 10.20 | 2/ |
| Gaz Métro L.P. | 2.20 | 2.20 | 2.40 | 2.27 | 3/ | 4.50 | 4.30 | 4.40 | 4.40 | | 21.50 | 21.90 | 20.20 | 21.20 | |
| Pacific Northern Gas | 2.13 | 2.59 | 2.49 | 2.40 | 1/ | 2.26 | 2.60 | 3.90 | 2.92 | 4/ | 11.20 | 11.70 | 19.60 | 14.17 | 1/ |
| Union Gas Limited | 2.40 | 2.40 | 2.60 | 2.47 | | 3.42 | 2.90 | 3.50 | 3.27 | | 15.10 | 14.80 | 16.50 | 15.47 | |
| **Median** | **2.20** | **2.40** | **2.40** | **2.33** | | **3.30** | **2.90** | **3.50** | **3.27** | | **15.10** | **14.80** | **16.50** | **15.47** | |
| **Electric Utilities** | | | | | | | | | | | | | | | |
| AltaLink L.P. | 1.80 | 1.80 | 2.20 | 1.93 | | 3.20 | 3.00 | 3.50 | 3.23 | | 12.70 | 12.70 | 13.70 | 13.03 | |
| CU Inc. | 2.10 | 2.40 | 2.40 | 2.30 | | 3.50 | 3.40 | 3.10 | 3.33 | | 16.90 | 17.90 | 14.90 | 16.57 | |
| Enersource | 2.50 | 2.20 | 2.20 | 2.30 | | 3.50 | 3.60 | 3.80 | 3.63 | | 18.10 | 18.40 | 19.40 | 18.63 | |
| ENMAX Corp. | 2.70 | 2.30 | 1.90 | 2.30 | | 3.80 | 3.30 | 3.10 | 3.40 | | 13.70 | 13.60 | 13.70 | 13.67 | |
| ENTEGRUS Inc. | 3.50 | 3.70 | 4.00 | 3.73 | | 5.50 | 5.40 | 5.50 | 5.47 | | 34.90 | 29.50 | 29.70 | 31.37 | |
| EPCOR Utilities Inc. | 1.50 | 2.10 | 2.20 | 1.93 | | 2.90 | 2.60 | 2.70 | 2.73 | | 15.10 | 16.40 | 13.20 | 14.90 | |
| FortisAlberta Inc. | 2.00 | 2.10 | 2.00 | 2.03 | | 3.80 | 3.80 | 3.90 | 3.83 | | 12.50 | 13.20 | 13.90 | 13.20 | |
| FortisBC Inc. | 2.05 | 2.04 | 2.10 | 2.06 | 1/ | 2.80 | 2.90 | 3.00 | 2.90 | 2/ | 11.20 | 11.90 | 11.60 | 11.57 | 2/ |
| Hamilton Utilities | 3.30 | 3.30 | 3.10 | 3.23 | | 5.10 | 4.60 | 5.20 | 4.97 | | 35.30 | 29.60 | 27.00 | 30.63 | |
| Hydro One Inc. | 2.80 | 2.10 | 2.30 | 2.40 | | 4.00 | 2.80 | 3.00 | 3.27 | | 14.50 | 11.40 | 12.20 | 12.70 | |
| Hydro Ottawa Holding Inc. | 4.10 | 4.30 | 4.30 | 4.23 | | 6.20 | 6.20 | 6.40 | 6.27 | | 25.50 | 27.30 | 27.80 | 26.87 | |
| London Hydro | 2.90 | 3.30 | 3.10 | 3.10 | 3/ | 4.80 | 5.20 | 5.50 | 5.17 | | 26.20 | 27.50 | 25.60 | 26.43 | |
| Maritime Electric | 2.30 | 2.30 | 2.40 | 2.33 | | 3.20 | 3.10 | 2.80 | 3.03 | | 17.40 | 16.30 | 13.60 | 15.77 | |
| Newfoundland Power | 2.53 | 2.40 | 2.41 | 2.45 | 1/ | 3.00 | 3.10 | 3.40 | 3.17 | 2/ | 15.80 | 15.00 | 17.60 | 16.13 | 2/ |
| Nova Scotia Power | 2.40 | 2.20 | 1.80 | 2.13 | | 3.10 | 3.00 | 3.40 | 3.17 | | 15.90 | 14.50 | 14.60 | 15.00 | |
| Toronto Hydro | 1.80 | 1.60 | 1.80 | 1.73 | | 3.40 | 3.30 | 3.60 | 3.43 | | 17.50 | 16.30 | 16.00 | 16.60 | |
| Veridian Corp. | 3.16 | 3.59 | 3.49 | 3.41 | 1/ | na | na | na | na | | 22.40 | 33.50 | 29.00 | 28.30 | 1/ |
| **Median** | **2.50** | **2.30** | **2.30** | **2.30** | | **3.50** | **3.30** | **3.45** | **3.37** | | **16.90** | **16.30** | **14.90** | **16.13** | |
| **Pipelines** | | | | | | | | | | | | | | | |
| Enbridge Pipelines Inc. | 2.90 | 2.70 | 2.30 | 2.63 | | 2.60 | 2.80 | 3.00 | 2.80 | | 6.60 | 8.10 | 13.20 | 9.30 | |
| NOVA Gas Transmission Ltd. | 2.15 | 1.94 | 2.18 | 2.09 | 1/ | na | na | na | na | | 14.20 | 14.20 | 14.30 | 14.23 | 1/ |
| Trans Québec & Maritimes Pipeline | 2.10 | 3.50 | 3.00 | 2.87 | | 3.60 | 4.40 | 4.10 | 4.03 | | 15.80 | 20.20 | 16.50 | 17.50 | |
| TransCanada PipeLines Ltd. | 2.30 | 1.90 | 1.80 | 2.00 | | 3.00 | 2.80 | 2.90 | 2.90 | | 13.00 | 12.40 | 11.90 | 12.43 | |
| Westcoast Energy Inc. | 2.70 | 2.40 | 2.60 | 2.57 | | 3.50 | 2.90 | 3.50 | 3.30 | | 17.90 | 13.30 | 15.80 | 15.67 | |
| **Median** | **2.30** | **2.40** | **2.30** | **2.57** | | **3.25** | **2.85** | **3.25** | **3.10** | | **14.20** | **13.30** | **14.30** | **14.23** | |
| **Medians** | | | | | | | | | | | | | | | |
| **All Companies** | **2.30** | **2.30** | **2.30** | **2.33** | | **3.42** | **3.10** | **3.50** | **3.30** | | **15.80** | **15.00** | **15.80** | **15.67** | |
| **All Investor Owned Companies** | **2.20** | **2.30** | **2.30** | **2.30** | | **3.20** | **3.00** | **3.40** | **3.20** | | **15.10** | **14.20** | **14.60** | **15.00** | |
| **All Gas & Electric Investor-Owned Companies Currently Rated by DBRS excl. FEI** | **2.20** | **2.20** | **2.30** | **2.27** | | **3.30** | **3.10** | **3.40** | **3.27** | | **15.80** | **14.80** | **14.90** | **15.47** | |

1/ Data from DBRS.
2/ Data from Moody's.
3/ 2010 data from S&P Credit Stats.
4/ Calculated from Annual Reports.
Source: Standard & Poor's Debt Rating Reports except where noted.

## DBRS CREDIT METRICS FOR INVESTOR-OWNED CANADIAN UTILITIES

| | EBIT Coverage | | | | | | EBITDA Coverage | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | 2007-11 Average | 2007 | 2008 | 2009 | 2010 | 2011 | 2007-11 Average |
| **FortisBC Energy Inc** | **1.99** | **1.92** | **1.96** | **2.17** | **2.17** | **2.04** | **2.72** | **2.62** | **2.72** | **3.04** | **3.00** | **2.82** |
| AltaLink L.P. | 1.78 | 1.84 | 1.94 | 2.31 | 2.51 | 2.08 | 3.44 | 3.60 | 3.79 | 3.99 | 4.02 | 3.77 |
| CU Inc. | 2.30 | 2.20 | 2.00 | 2.40 | 3.00 | 2.38 | 3.90 | 3.80 | 3.00 | 3.70 | 4.30 | 3.74 |
| Enbridge Gas Distribution | 2.62 | 2.55 | 2.87 | 2.62 | 2.69 | 2.67 | 4.06 | 3.92 | 4.51 | 4.41 | 4.65 | 4.31 |
| FortisAlberta Inc. | 2.05 | 2.02 | 2.17 | 2.09 | 2.06 | 2.08 | 4.17 | 4.02 | 4.12 | 4.28 | 4.11 | 4.14 |
| FortisBC Inc. | 2.04 | 2.05 | 2.04 | 2.10 | 2.40 | 2.13 | 3.04 | 3.09 | 3.06 | 3.21 | 3.52 | 3.18 |
| Gaz Metro | 2.52 | 2.52 | 2.43 | 2.37 | 2.41 | 2.45 | 4.16 | 4.18 | 4.21 | 3.97 | 4.08 | 4.12 |
| Newfoundland Power [1/] | 2.20 | 2.53 | 2.40 | 2.41 | 2.38 | 2.38 | 3.17 | 3.84 | 3.71 | 3.71 | 4.01 | 3.69 |
| Nova Scotia Power | 2.83 | 2.67 | 2.69 | 2.04 | 1.67 | 2.38 | 4.30 | 4.22 | 4.42 | 3.72 | 3.23 | 3.98 |
| Union Gas Limited | 2.18 | 2.36 | 2.35 | 2.55 | 2.66 | 2.42 | 3.29 | 3.56 | 3.54 | 3.81 | 3.99 | 3.64 |
| **Median (Excluding FEI)** | **2.20** | **2.36** | **2.35** | **2.37** | **2.41** | **2.38** | **3.90** | **3.84** | **3.79** | **3.81** | **4.02** | **3.77** |

| | Cash Flow/Total Debt | | | | | |
|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | 2007-11 Average |
| **FortisBC Energy Inc** | **8.9** | **10.1** | **10.3** | **10.9** | **11.8** | **10.4** |
| AltaLink L.P. | 12.6 | 13.3 | 14.8 | 14.8 | 13.2 | 13.7 |
| CU Inc. | 17.9 | 18.5 | 13.2 | 18.3 | 17.7 | 17.1 |
| Enbridge Gas Distribution | 16.8 | 17.1 | 21.7 | 19.5 | 19.4 | 18.9 |
| FortisAlberta Inc. | 18.2 | 15.7 | 15.9 | 17.4 | 16.5 | 16.7 |
| FortisBC Inc. | 11.4 | 11.4 | 12.2 | 12.4 | 13.3 | 12.1 |
| Gaz Metro | 29.9 | 21.5 | 22.3 | 18.4 | 24.0 | 23.2 |
| Newfoundland Power [1/] | 12.9 | 16.2 | 15.0 | 17.8 | 17.5 | 15.9 |
| Nova Scotia Power | 21.7 | 19.6 | 17.1 | 12.6 | 15.1 | 17.2 |
| Union Gas Limited | 15.1 | 14.9 | 14.1 | 16.7 | 16.2 | 15.4 |
| **Median (Excluding FEI)** | **16.8** | **16.2** | **15.0** | **17.4** | **16.5** | **16.7** |

[1/] Newfoundland Power 2011 data 12 months ending September 30, 2011.

Source: DBRS Reports

## CREDIT METRICS FOR U.S. A-RATED GAS UTILITIES
## (2010)

| | EBIT Coverage (1) | FFO Interest Coverage (2) | FFO To Debt (3) | EBITDA Coverage (4) | Equity Ratio (5) |
|---|---|---|---|---|---|
| **Indiana Gas** | 3.3 | 4.3 | 19.8 | 5.0 | 49.2% |
| **Laclede Group** | 4.4 | 5.6 | 30.3 | 4.9 | 56.0% |
| Laclede Gas | | | | | |
| **New Jersey Natural Gas** | 6.8 | 8.4 | 32.0 | 8.2 | 57.0% |
| **Integrys Energy Group** | 3.7 | 5.7 | 25.2 | 4.0 | 49.3% |
| North Shore Gas | | | | | |
| Peoples Gas Light & Coke | | | | | |
| **Northwest Natural Gas** | 3.8 | 5.4 | 21.9 | 5.3 | 44.3% |
| **NStar LLC** | 5.0 | 6.1 | 21.2 | 5.8 | 39.6% |
| NStar Gas | | | | | |
| **Piedmont Natural Gas** | 4.9 | 5.5 | 26.2 | 5.3 | 51.0% |
| **Questar Gas** | 3.6 | 6.1 | 25.9 | 5.0 | 43.9% |
| **Southern California Gas** | 4.6 | 5.7 | 27.1 | 6.9 | 42.3% |
| **WGL Holdings** | 5.5 | 7.1 | 30.4 | 7.5 | 53.7% |
| Washington Gas Light | | | | | |
| **Wisconsin Energy Corp** | 2.8 | 4.8 | 18.4 | 3.8 | 42.5% |
| Wisconsin Gas | | | | | |
| **Median** | **4.4** | **5.7** | **25.9** | **5.3** | **49.2%** |

Source: Standard and Poor's

## CREDIT METRICS OF SAMPLE OF U.S. UTILITIES

| Company | EBIT Coverage 2008 | 2009 | 2010 | 3 Year Average | EBITDA Coverage 2008 | 2009 | 2010 | 3 Year Average |
|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 3.70 | 4.10 | 4.40 | 4.07 | 4.90 | 5.50 | 5.80 | 5.40 |
| Alliant Energy Corp. | 3.20 | 2.60 | 3.30 | 3.03 | 4.60 | 3.90 | 4.80 | 4.43 |
| Atmos Energy Corp. | 2.88 | 2.63 | 2.93 | 2.81 | 4.20 | 3.90 | 4.20 | 4.10 |
| Consolidated Edison | 3.00 | 3.10 | 3.50 | 3.20 | 4.10 | 4.30 | 4.80 | 4.40 |
| Integrys Energy Group Inc. | 2.00 | 3.10 | 3.70 | 2.93 | 3.00 | 4.10 | 5.00 | 4.03 |
| Northwest Natural Gas | 3.80 | 3.80 | 3.80 | 3.80 | 5.60 | 5.10 | 5.10 | 5.27 |
| Piedmont Natural Gas | 3.70 | 4.90 | 4.90 | 4.50 | 4.70 | 6.20 | 5.30 | 5.40 |
| Southern Company | 3.30 | 3.20 | 3.60 | 3.37 | 4.80 | 4.50 | 4.90 | 4.73 |
| Vectren Corp. | 3.10 | 2.90 | 2.90 | 2.97 | 4.60 | 4.80 | 5.00 | 4.80 |
| WGL Holdings Inc. | 5.20 | 5.20 | 5.10 | 5.17 | 6.80 | 7.20 | 7.50 | 7.17 |
| Wisconsin Energy Corp. | 1.10 | 2.20 | 2.80 | 2.03 | 2.30 | 3.50 | 3.80 | 3.20 |
| Xcel Energy Inc. | 2.50 | 2.70 | 2.90 | 2.70 | 3.80 | 4.00 | 4.20 | 4.00 |
| **Median** | **3.15** | **3.10** | **3.55** | **3.12** | **4.60** | **4.40** | **4.95** | **4.58** |

| Company | FFO Interest Coverage 2008 | 2009 | 2010 | 3 Year Average | | FFO To Debt 2008 | 2009 | 2010 | 3 Year Average |
|---|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 3.50 | 4.37 | 4.52 | 4.13 | [1/] | 18.80 | 20.90 | 20.00 | 19.90 |
| Alliant Energy Corp. | 4.50 | 4.50 | 5.30 | 4.77 | | 20.00 | 22.70 | 24.80 | 22.50 |
| Atmos Energy Corp. | 4.24 | 3.91 | 4.48 | 4.21 | | 21.95 | 21.36 | 25.52 | 22.94 |
| Consolidated Edison | 3.20 | 4.30 | 5.30 | 4.27 | | 9.30 | 16.40 | 21.00 | 15.57 |
| Integrys Energy Group Inc. | 5.20 | 5.50 | 5.70 | 5.47 | | 18.20 | 25.50 | 25.20 | 22.97 |
| Northwest Natural Gas | 5.30 | 3.70 | 5.40 | 4.80 | | 21.90 | 17.40 | 21.90 | 20.40 |
| Piedmont Natural Gas | 4.60 | 6.40 | 5.50 | 5.50 | | 21.80 | 24.80 | 26.20 | 24.27 |
| Southern Company | 4.20 | 4.40 | 4.90 | 4.50 | | 17.20 | 18.10 | 20.10 | 18.47 |
| Vectren Corp. | 5.10 | 5.00 | 5.40 | 5.17 | | 21.20 | 21.40 | 25.50 | 22.70 |
| WGL Holdings Inc. | 7.00 | 6.70 | 6.30 | 6.67 | | 30.40 | 26.90 | 27.60 | 28.30 |
| Wisconsin Energy Corp. | 5.00 | 4.70 | 4.80 | 4.83 | | 18.40 | 16.70 | 18.40 | 17.83 |
| Xcel Energy Inc. | 3.90 | 4.20 | 4.40 | 4.17 | | 17.10 | 18.80 | 19.00 | 18.30 |
| **Median** | **4.55** | **4.45** | **5.30** | **4.78** | | **19.40** | **21.13** | **23.35** | **21.45** |

[1/] Data from S&P Credit Stats.

Source: Standard & Poor's Debt Rating Reports except where noted.

# HISTORIC EQUITY MARKET RISK PREMIUMS
## (Arithmetic Averages)

### Canada
### (1947-2011)

| Stock Return | Bond Total Return | Risk Premium |
|---|---|---|
| 11.8 | 7.1 | 4.7 |
| Stock Return | Bond Income Return | Risk Premium |
| 11.8 | 6.7 | 5.0 |

### United States
### (1947-2011)

| Stock Return | Bond Total Return | Risk Premium |
|---|---|---|
| 12.3 | 6.6 | 5.7 |
| Stock Return | Bond Income Return | Risk Premium |
| 12.3 | 5.9 | 6.4 |

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

# HISTORIC EQUITY MARKET RISK PREMIUMS
## (Arithmetic Averages)

### Canada
### (1924-2011)

| Stock Return | Bond Total Return | Risk Premium |
|---|---|---|
| 11.4 | 6.6 | 4.8 |
| Stock Return | Bond Income Return | Risk Premium |
| 11.4 | 6.0 | 5.4 |

### United States
### (1926-2011)

| Stock Return | Bond Total Return | Risk Premium |
|---|---|---|
| 11.8 | 6.1 | 5.6 |
| Stock Return | Bond Income Return | Risk Premium |
| 11.8 | 5.2 | 6.6 |

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

**FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE**
**(Percentages)**

| Five Year Periods Ending: | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **S&P / TSX Composite** | **3.57** | **4.68** | **4.84** | **5.40** | **5.87** | **5.83** | **4.97** | **4.59** | **4.04** | **3.24** | **2.86** | **4.35** | **4.88** | **4.88** | **4.95** | **4.60** |
| **10 Sector Indices** | | | | | | | | | | | | | | | | |
| Consumer Discretionary | 3.69 | 4.36 | 4.62 | 4.99 | 5.38 | 5.73 | 5.35 | 5.00 | 4.35 | 3.69 | 3.08 | 3.84 | 4.07 | 4.04 | 4.13 | 4.42 |
| Consumer Staples | 3.57 | 4.01 | 3.70 | 4.04 | 4.17 | 4.76 | 4.45 | 4.37 | 4.05 | 3.88 | 2.97 | 3.24 | 3.36 | 3.68 | 3.54 | 3.85 |
| Energy | 5.60 | 6.16 | 7.31 | 7.97 | 8.30 | 8.10 | 6.98 | 5.72 | 5.56 | 5.46 | 5.40 | 7.04 | 7.37 | 6.71 | 6.72 | 6.69 |
| Financials | 4.27 | 5.89 | 5.92 | 6.22 | 6.17 | 6.06 | 4.58 | 4.23 | 3.77 | 3.36 | 2.97 | 3.99 | 5.38 | 5.59 | 5.62 | 4.93 |
| Health Care | 6.62 | 7.73 | 8.19 | 9.38 | 9.00 | 9.39 | 8.93 | 8.68 | 6.98 | 6.57 | 5.45 | 4.92 | 5.38 | 5.89 | 7.47 | 7.37 |
| Industrials | 4.13 | 4.93 | 4.69 | 5.12 | 6.50 | 7.18 | 6.92 | 6.87 | 6.48 | 5.16 | 4.08 | 4.87 | 5.48 | 5.51 | 5.66 | 5.57 |
| Information Technology | 7.99 | 9.17 | 10.35 | 12.27 | 15.16 | 17.12 | 16.64 | 17.09 | 15.81 | 13.36 | 10.20 | 11.82 | 11.68 | 12.14 | 12.60 | 12.89 |
| Materials | 5.87 | 6.98 | 7.22 | 7.29 | 7.40 | 7.25 | 5.89 | 5.65 | 5.67 | 5.88 | 5.59 | 7.96 | 8.48 | 8.60 | 8.69 | 6.96 |
| Telecommunication Services | 3.66 | 5.82 | 7.37 | 7.87 | 8.46 | 8.71 | 7.54 | 5.74 | 4.97 | 4.64 | 4.18 | 5.08 | 5.07 | 4.93 | 4.59 | 5.91 |
| Utilities | 3.12 | 3.80 | 4.00 | 4.80 | 5.06 | 4.88 | 4.49 | 4.09 | 3.36 | 3.13 | 3.49 | 4.04 | 4.32 | 4.30 | 4.09 | 4.07 |
| **Mean** | **4.85** | **5.89** | **6.34** | **7.00** | **7.56** | **7.92** | **7.18** | **6.75** | **6.10** | **5.51** | **4.74** | **5.68** | **6.06** | **6.14** | **6.31** | **6.27** |
| **Median** | **4.20** | **5.85** | **6.57** | **6.76** | **6.95** | **7.21** | **6.41** | **5.68** | **5.27** | **4.90** | **4.13** | **4.90** | **5.38** | **5.55** | **5.64** | **5.69** |

**Ratios of Standard Deviations**

| S&P/TSX Utilities Index as a Percent of: | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **10 Sector Indices (Mean)** | **0.64** | **0.65** | **0.63** | **0.69** | **0.67** | **0.62** | **0.63** | **0.61** | **0.55** | **0.57** | **0.74** | **0.71** | **0.71** | **0.70** | **0.65** | **0.65** |
| **10 Sector Indices (Median)** | **0.74** | **0.65** | **0.61** | **0.71** | **0.73** | **0.68** | **0.70** | **0.72** | **0.64** | **0.64** | **0.85** | **0.82** | **0.80** | **0.77** | **0.73** | **0.72** |

Source: *TSX Review*

**5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES**

| | Consumer Discretionary (1) | Consumer Staples (2) | Energy (3) | Financials (4) | Health Care (5) | Industrials (6) | Information Technology (7) | Materials (8) | Telecommunication Services (9) | Utilities (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 0.82 | 0.62 | 0.97 | 0.94 | 0.60 | 0.97 | 1.57 | 1.32 | 0.64 | 0.53 |
| 1998 | 0.80 | 0.60 | 0.85 | 1.12 | 1.01 | 0.93 | 1.41 | 1.12 | 0.92 | 0.55 |
| 1999 | 0.73 | 0.44 | 0.90 | 1.00 | 1.00 | 0.78 | 1.55 | 1.04 | 1.11 | 0.30 |
| 2000 | 0.69 | 0.23 | 0.66 | 0.78 | 1.09 | 0.72 | 1.78 | 0.74 | 0.92 | 0.14 |
| 2001 | 0.68 | 0.10 | 0.49 | 0.66 | 0.98 | 0.82 | 2.13 | 0.60 | 0.94 | -0.03 |
| 2002 | 0.73 | 0.08 | 0.43 | 0.66 | 0.99 | 0.86 | 2.28 | 0.57 | 0.93 | -0.06 |
| 2003 | 0.74 | -0.08 | 0.26 | 0.38 | 0.85 | 0.91 | 2.74 | 0.43 | 0.83 | -0.25 |
| 2004 | 0.80 | -0.07 | 0.17 | 0.39 | 0.82 | 1.05 | 2.87 | 0.41 | 0.58 | -0.13 |
| 2005 | 0.83 | 0.07 | 0.48 | 0.56 | 0.72 | 1.13 | 2.68 | 0.77 | 0.74 | 0.00 |
| 2006 | 0.86 | 0.37 | 1.03 | 0.68 | 0.85 | 1.06 | 2.07 | 1.32 | 0.52 | 0.25 |
| 2007 | 0.73 | 0.54 | 1.44 | 0.51 | 0.54 | 0.96 | 1.12 | 1.45 | 0.62 | 0.46 |
| 2008 | 0.59 | 0.32 | 1.43 | 0.61 | 0.48 | 0.81 | 1.43 | 1.30 | 0.55 | 0.49 |
| 2009 | 0.56 | 0.28 | 1.35 | 0.80 | 0.41 | 0.83 | 1.22 | 1.24 | 0.47 | 0.41 |
| 2010 | 0.55 | 0.33 | 1.24 | 0.85 | 0.39 | 0.87 | 1.37 | 1.22 | 0.46 | 0.42 |
| 2011 | 0.52 | 0.31 | 1.25 | 0.85 | 0.37 | 0.89 | 1.49 | 1.19 | 0.45 | 0.43 |

Source: *TSX Review*

## TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS
## (1956-2003)

| | Sub-Index Compound Returns [1/] | | | | | | Sub-Index Betas | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 56-03 | 56-97 | 64-73 | 74-83 | 84-93 | 94-03 | 56-03 | 56-97 | 64-73 | 74-83 | 84-93 | 94-03 |
| Metals/Minerals | 7.8 | 7.6 | 7.5 | 11.2 | 6.8 | 7.2 | 1.15 | 1.23 | 1.14 | 1.22 | 1.37 | 0.87 |
| Gold/Precious Metals | 9.5 | 10.4 | 16.2 | 16.0 | 11.0 | -2.7 | 0.85 | 0.96 | 0.36 | 1.31 | 1.24 | 0.64 |
| Oil and Gas | 9.5 | 8.4 | 14.6 | 11.9 | 4.5 | 15.3 | 1.06 | 1.20 | 1.25 | 1.40 | 0.98 | 0.52 |
| Paper/Forest Products | 7.1 | 7.4 | 4.8 | 11.8 | 10.3 | 2.6 | 1.02 | 1.07 | 1.15 | 1.00 | 1.27 | 0.85 |
| Consumer Products | 11.3 | 11.9 | 10.2 | 13.8 | 11.2 | 9.6 | 0.83 | 0.86 | 0.84 | 0.90 | 0.89 | 0.73 |
| Industrial Products | 7.2 | 9.6 | 8.3 | 10.9 | 6.0 | 1.1 | 1.17 | 1.02 | 1.11 | 0.87 | 1.08 | 1.69 |
| Real Estate [2/] | 5.3 | 5.5 | 0.7 | 16.7 | -2.3 | 1.3 | 1.00 | 1.18 | 1.21 | 1.28 | 1.06 | 0.46 |
| Transportation/Environmental | 10.1 | 11.4 | 12.7 | 18.4 | 3.0 | 8.8 | 0.94 | 1.04 | 0.94 | 1.08 | 1.22 | 0.62 |
| Pipelines | 11.7 | 12.1 | 5.2 | 13.8 | 13.7 | 13.1 | 0.68 | 0.85 | 0.80 | 0.92 | 0.76 | 0.02 |
| Utilities | 11.0 | 10.7 | 3.3 | 17.8 | 11.0 | 16.3 | 0.54 | 0.48 | 0.50 | 0.47 | 0.40 | 0.79 |
| Communications/Media | 13.5 | 15.0 | 19.1 | 15.3 | 12.9 | 7.5 | 0.77 | 0.77 | 0.96 | 0.69 | 0.95 | 0.80 |
| Merchandising | 10.1 | 10.7 | 10.6 | 12.2 | 8.7 | 7.2 | 0.78 | 0.86 | 0.93 | 0.84 | 0.83 | 0.46 |
| Finance | 12.4 | 12.8 | 12.0 | 11.7 | 11.6 | 17.9 | 0.83 | 0.85 | 0.95 | 0.71 | 0.93 | 0.77 |
| Conglomerates | 10.8 | 10.8 | 12.8 | 15.2 | 9.5 | 13.9 | 0.94 | 1.03 | 1.26 | 0.97 | 1.20 | 0.68 |
| **Adjusted R Square [3/]** | | | | | | | **47%** | **44%** | **1%** | **1%** | **11%** | **9%** |
| **Beta [4/]** | | | | | | | **-0.088** | **-0.082** | **-0.020** | **-0.008** | **-0.056** | **-0.053** |

[1/] Annualized rate of return at which capital has compounded over time.

[2/] Data only available starting July 1961

[3/] Represents percentage of variation in sub-index returns explained by the sub-index betas.

[4/] Represents relationship between sub-index returns and sub-index betas.

Source: *TSX Review*

## S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS
## (1988-2011)

| | Sector Compound Returns [1] | | | Sector Betas | | |
|---|---|---|---|---|---|---|
| | 88-11 | 88-97 | 02-11 | 88-11 | 88-97 | 02-11 |
| Consumer Discretionary | 5.9 | 10.2 | 1.3 | 0.72 | 0.90 | 0.63 |
| Consumer Staples | 11.2 | 12.7 | 7.5 | 0.34 | 0.73 | 0.34 |
| Energy | 10.2 | 8.4 | 13.3 | 0.82 | 0.76 | 1.19 |
| Financials | 12.4 | 18.3 | 8.4 | 0.80 | 1.04 | 0.80 |
| Health Care | 6.4 | 15.5 | -0.9 | 0.73 | 0.81 | 0.50 |
| Industrials | 6.3 | 8.3 | 4.7 | 0.94 | 1.13 | 0.92 |
| Information Technology | 2.2 | 21.8 | -19.8 | 1.72 | 1.21 | 1.68 |
| Materials | 6.6 | 3.4 | 13.6 | 0.99 | 1.26 | 1.23 |
| Telecommunication Services | 13.0 | 15.4 | 4.4 | 0.66 | 0.58 | 0.46 |
| Utilities | 10.4 | 11.5 | 12.3 | 0.29 | 0.62 | 0.38 |
| **Adjusted R Square [2]** | | | | **52%** | **1%** | **18%** |
| **Beta [3]** | | | | **-0.063** | **-0.017** | **-0.094** |

[1] Data only available starting December 1987. Annualized rate of return at which capital has compounded over time.

[2] Represents percentage of variation in sector returns explained by the sector betas.

[3] Represents relationship between sector returns and sector betas.

Source: *TSX Review*

# MONTHLY BETAS FOR REGULATED CANADIAN UTILITIES

## "Raw" Monthly Price Betas
Five Year Period Ending:

| COMPANY | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities Limited | 0.46 | 0.54 | 0.48 | 0.55 | 0.63 | 0.62 | 0.54 | 0.38 | 0.27 | 0.19 | 0.05 | 0.03 | 0.20 | 0.32 | 0.58 | 0.19 | 0.06 | 0.06 | 0.03 |
| Emera Inc. | na | na | na | 0.52 | 0.40 | 0.55 | 0.41 | 0.27 | 0.20 | 0.15 | -0.05 | 0.01 | 0.07 | 0.12 | 0.24 | 0.17 | 0.16 | 0.21 | 0.21 |
| Enbridge Inc. | 0.35 | 0.53 | 0.46 | 0.44 | 0.43 | 0.48 | 0.26 | 0.07 | -0.10 | -0.18 | -0.37 | -0.32 | -0.19 | 0.22 | 0.54 | 0.30 | 0.30 | 0.32 | 0.30 |
| Fortis Inc. | 0.35 | 0.44 | 0.51 | 0.37 | 0.30 | 0.49 | 0.33 | 0.23 | 0.14 | 0.13 | -0.06 | 0.01 | 0.21 | 0.48 | 0.65 | 0.21 | 0.20 | 0.16 | 0.14 |
| TransCanada Corporation | 0.40 | 0.57 | 0.56 | 0.52 | 0.36 | 0.55 | 0.21 | 0.15 | -0.08 | -0.09 | -0.38 | -0.16 | -0.15 | 0.34 | 0.52 | 0.38 | 0.39 | 0.39 | 0.37 |
| **Mean** | 0.39 | 0.52 | 0.50 | 0.48 | 0.42 | 0.54 | 0.35 | 0.22 | 0.08 | 0.04 | -0.16 | -0.08 | 0.03 | 0.30 | 0.51 | 0.25 | 0.22 | 0.23 | 0.21 |
| **Median** | 0.38 | 0.54 | 0.50 | 0.52 | 0.40 | 0.55 | 0.33 | 0.23 | 0.14 | 0.13 | -0.06 | 0.01 | 0.07 | 0.32 | 0.54 | 0.21 | 0.20 | 0.21 | 0.21 |
| **TSE Gas/Electric Index** | 0.42 | 0.48 | 0.52 | 0.52 | 0.46 | 0.55 | 0.38 | 0.21 | 0.17 | 0.14 | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| **S&P/TSX Utilities** | 0.55 | 0.63 | 0.67 | 0.65 | 0.53 | 0.55 | 0.30 | 0.14 | -0.03 | -0.06 | -0.25 | -0.13 | 0.00 | 0.25 | 0.46 | 0.49 | 0.41 | 0.42 | 0.43 |

## Adjusted Betas [1/]
Five Year Period Ending:

| COMPANY | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities Limited | 0.64 | 0.69 | 0.65 | 0.70 | 0.75 | 0.75 | 0.69 | 0.58 | 0.51 | 0.46 | 0.37 | 0.35 | 0.47 | 0.54 | 0.72 | 0.45 | 0.37 | 0.37 | 0.35 |
| Emera Inc. | NA | NA | NA | 0.68 | 0.60 | 0.70 | 0.60 | 0.51 | 0.46 | 0.43 | 0.29 | 0.33 | 0.38 | 0.41 | 0.49 | 0.44 | 0.44 | 0.47 | 0.47 |
| Enbridge Inc. | 0.56 | 0.69 | 0.64 | 0.62 | 0.62 | 0.65 | 0.50 | 0.38 | 0.26 | 0.21 | 0.08 | 0.12 | 0.21 | 0.48 | 0.69 | 0.53 | 0.53 | 0.54 | 0.53 |
| Fortis Inc. | 0.57 | 0.62 | 0.67 | 0.58 | 0.53 | 0.66 | 0.55 | 0.48 | 0.42 | 0.41 | 0.29 | 0.34 | 0.47 | 0.65 | 0.77 | 0.47 | 0.46 | 0.44 | 0.42 |
| TransCanada Corporation | 0.60 | 0.71 | 0.71 | 0.68 | 0.57 | 0.70 | 0.47 | 0.43 | 0.28 | 0.27 | 0.08 | 0.22 | 0.23 | 0.56 | 0.68 | 0.58 | 0.59 | 0.59 | 0.58 |
| **Mean** | 0.59 | 0.68 | 0.67 | 0.65 | 0.61 | 0.69 | 0.56 | 0.48 | 0.39 | 0.36 | 0.22 | 0.27 | 0.35 | 0.53 | 0.67 | 0.50 | 0.48 | 0.48 | 0.47 |
| **Median** | 0.58 | 0.69 | 0.66 | 0.68 | 0.60 | 0.70 | 0.55 | 0.48 | 0.42 | 0.41 | 0.29 | 0.33 | 0.38 | 0.54 | 0.69 | 0.47 | 0.46 | 0.47 | 0.47 |
| **TSE Gas/Electric Index** | 0.61 | 0.65 | 0.68 | 0.68 | 0.64 | 0.70 | 0.59 | 0.47 | 0.44 | 0.42 | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| **S&P/TSX Utilities** | 0.70 | 0.76 | 0.78 | 0.77 | 0.69 | 0.70 | 0.53 | 0.42 | 0.31 | 0.29 | 0.16 | 0.24 | 0.33 | 0.50 | 0.64 | 0.66 | 0.60 | 0.61 | 0.62 |

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

## MONTHLY BETAS AND $R^2$s FOR REGULATED CANADIAN UTILITIES

| Beta Ending | Canadian Utilities Limited | | Emera Inc. | | Enbridge Inc. | | Fortis Inc. | | TransCanada Corp. | | S&P/TSX Utilities | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Beta | $R^2$ | Beta | $R^2$ | Beta | $R^2$ | Beta | $R^2$ | Beta | $R^2$ | Beta | $R^2$ |
| 2004 | 0.03 | 0.1% | 0.01 | 0.0% | -0.32 | 7.0% | 0.01 | 0.0% | -0.16 | 1.6% | -0.13 | 2.3% |
| 2005 | 0.20 | 4.2% | 0.07 | 0.5% | -0.19 | 2.8% | 0.21 | 3.0% | -0.15 | 2.5% | 0.00 | 0.0% |
| 2006 | 0.32 | 4.9% | 0.12 | 1.1% | 0.22 | 4.2% | 0.48 | 9.0% | 0.34 | 10.0% | 0.25 | 6.8% |
| 2007 | 0.58 | 10.1% | 0.24 | 3.2% | 0.54 | 12.5% | 0.65 | 11.8% | 0.52 | 14.8% | 0.46 | 14.3% |
| 2008 | 0.19 | 1.9% | 0.17 | 3.5% | 0.30 | 7.8% | 0.21 | 2.8% | 0.38 | 16.4% | 0.49 | 28.1% |
| 2009 | 0.06 | 0.2% | 0.16 | 3.3% | 0.30 | 10.0% | 0.20 | 2.9% | 0.39 | 19.7% | 0.41 | 21.5% |
| 2010 | 0.06 | 0.2% | 0.21 | 4.9% | 0.32 | 11.2% | 0.16 | 2.3% | 0.39 | 19.1% | 0.42 | 22.3% |
| 2011 | 0.03 | 0.1% | 0.21 | 5.4% | 0.30 | 10.3% | 0.14 | 2.4% | 0.37 | 17.7% | 0.43 | 27.1% |

Source: Standard and Poor's *Research Insight*

## WEEKLY BETAS FOR REGULATED CANADIAN UTILITIES

| | "Raw" Weekly Price Betas Five Year Period Ending: | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **COMPANY** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** |
| Canadian Utilities Limited | 0.14 | 0.25 | 0.32 | 0.50 | 0.42 | 0.40 | 0.39 | 0.38 |
| Emera Inc. | 0.19 | 0.03 | 0.11 | 0.20 | 0.32 | 0.35 | 0.40 | 0.43 |
| Enbridge Inc. | 0.01 | 0.21 | 0.47 | 0.64 | 0.58 | 0.52 | 0.49 | 0.49 |
| Fortis Inc. | -0.06 | 0.21 | 0.26 | 0.38 | 0.50 | 0.46 | 0.50 | 0.53 |
| TransCanada Corporation | -0.02 | 0.14 | 0.35 | 0.48 | 0.45 | 0.44 | 0.44 | 0.44 |
| **Mean** | **0.05** | **0.17** | **0.30** | **0.44** | **0.46** | **0.43** | **0.44** | **0.45** |
| **Median** | **0.01** | **0.21** | **0.32** | **0.48** | **0.45** | **0.44** | **0.44** | **0.44** |
| **S&P/TSX Utilities** | 0.04 | 0.16 | 0.31 | 0.42 | 0.53 | 0.53 | 0.55 | 0.56 |

| | Adjusted Betas [1/] Five Year Period Ending: | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **COMPANY** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** |
| Canadian Utilities Limited | 0.43 | 0.49 | 0.55 | 0.66 | 0.61 | 0.60 | 0.59 | 0.59 |
| Emera Inc. | 0.46 | 0.35 | 0.40 | 0.47 | 0.54 | 0.56 | 0.59 | 0.62 |
| Enbridge Inc. | 0.34 | 0.47 | 0.65 | 0.76 | 0.72 | 0.68 | 0.66 | 0.66 |
| Fortis Inc. | 0.29 | 0.47 | 0.50 | 0.59 | 0.67 | 0.64 | 0.66 | 0.68 |
| TransCanada Corporation | 0.31 | 0.42 | 0.57 | 0.65 | 0.63 | 0.62 | 0.63 | 0.62 |
| **Mean** | **0.37** | **0.44** | **0.53** | **0.63** | **0.64** | **0.62** | **0.63** | **0.63** |
| **Median** | **0.34** | **0.47** | **0.55** | **0.65** | **0.63** | **0.62** | **0.63** | **0.62** |
| **S&P/TSX Utilities** | 0.36 | 0.44 | 0.53 | 0.61 | 0.69 | 0.69 | 0.70 | 0.70 |

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

## MONTHLY BETAS FOR SAMPLE OF U.S. UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

| COMPANY | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 0.33 | 0.40 | 0.39 | 0.45 | 0.62 | 0.60 | 0.45 | 0.29 | 0.29 | 0.24 | 0.21 | 0.30 | 0.37 | 0.36 | 0.50 | 0.31 | 0.40 | 0.46 | 0.45 |
| Alliant Energy Corp. | 0.46 | 0.55 | 0.61 | 0.46 | 0.26 | 0.18 | 0.08 | 0.09 | -0.02 | 0.10 | 0.24 | 0.34 | 0.40 | 0.80 | 0.72 | 0.59 | 0.57 | 0.53 | 0.53 |
| Atmos Energy Corp. | 0.32 | 0.32 | 0.50 | 0.76 | 0.08 | 0.16 | 0.19 | 0.00 | -0.17 | -0.02 | -0.03 | 0.05 | 0.18 | 0.41 | 0.85 | 0.51 | 0.50 | 0.52 | 0.52 |
| Consolidated Edison | 0.57 | 0.55 | 0.53 | 0.59 | 0.66 | 0.32 | 0.18 | 0.09 | -0.04 | -0.16 | -0.14 | -0.05 | 0.00 | 0.14 | 0.39 | 0.25 | 0.29 | 0.31 | 0.26 |
| Integrys Energy Group Inc. | 0.34 | 0.31 | 0.38 | 0.25 | 0.29 | 0.16 | 0.10 | 0.01 | -0.03 | -0.01 | 0.06 | 0.15 | 0.17 | 0.37 | 0.56 | 0.48 | 0.91 | 0.89 | 0.87 |
| Northwest Natural Gas | 0.21 | 0.19 | 0.19 | 0.14 | 0.38 | 0.46 | 0.18 | 0.11 | 0.06 | -0.11 | -0.19 | 0.01 | 0.04 | 0.14 | 0.74 | 0.36 | 0.25 | 0.31 | 0.31 |
| Piedmont Natural Gas | 0.35 | 0.43 | 0.39 | 0.27 | 0.32 | 0.51 | 0.28 | 0.13 | 0.15 | 0.09 | -0.03 | 0.13 | 0.28 | 0.35 | 0.58 | 0.06 | 0.19 | 0.23 | 0.31 |
| Southern Company | 0.51 | 0.47 | 0.39 | 0.53 | 0.42 | 0.15 | 0.11 | -0.05 | -0.36 | -0.45 | -0.47 | -0.47 | -0.49 | -0.06 | 0.34 | 0.37 | 0.34 | 0.35 | 0.30 |
| Vectren Corp. | 0.22 | 0.23 | 0.23 | 0.64 | 0.57 | 0.34 | 0.16 | 0.24 | 0.20 | 0.23 | 0.35 | 0.46 | 0.32 | 0.49 | 0.56 | 0.25 | 0.37 | 0.42 | 0.41 |
| WGL Holdings Inc. | 0.29 | 0.36 | 0.39 | 0.75 | 0.62 | 0.47 | 0.28 | 0.25 | 0.19 | 0.14 | 0.11 | 0.22 | 0.21 | 0.27 | 0.69 | 0.24 | 0.17 | 0.25 | 0.28 |
| Wisconsin Energy Corp. | 0.47 | 0.53 | 0.52 | 0.58 | 0.43 | 0.31 | 0.14 | 0.11 | -0.02 | -0.10 | -0.09 | 0.06 | 0.02 | 0.18 | 0.56 | 0.45 | 0.39 | 0.37 | 0.34 |
| Xcel Energy Inc. | 0.63 | 0.62 | 0.37 | 0.60 | 0.50 | 0.34 | 0.27 | 0.19 | -0.01 | 0.41 | 0.56 | 0.70 | 0.80 | 1.48 | 0.60 | 0.56 | 0.46 | 0.44 | 0.39 |
| **Mean** | 0.39 | 0.41 | 0.41 | 0.50 | 0.43 | 0.33 | 0.20 | 0.12 | 0.02 | 0.03 | 0.05 | 0.16 | 0.19 | 0.41 | 0.59 | 0.37 | 0.40 | 0.42 | 0.41 |
| **Median** | 0.34 | 0.41 | 0.39 | 0.56 | 0.43 | 0.33 | 0.18 | 0.11 | -0.01 | 0.04 | 0.01 | 0.14 | 0.19 | 0.35 | 0.57 | 0.37 | 0.38 | 0.40 | 0.37 |

Adjusted Betas [1/]
Five Year Period Ending:

| COMPANY | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 0.55 | 0.60 | 0.59 | 0.63 | 0.74 | 0.73 | 0.63 | 0.52 | 0.53 | 0.49 | 0.47 | 0.53 | 0.58 | 0.57 | 0.66 | 0.54 | 0.60 | 0.64 | 0.63 |
| Alliant Energy Corp. | 0.64 | 0.70 | 0.74 | 0.64 | 0.50 | 0.45 | 0.38 | 0.39 | 0.31 | 0.40 | 0.49 | 0.56 | 0.60 | 0.87 | 0.81 | 0.73 | 0.71 | 0.68 | 0.68 |
| Atmos Energy Corp. | 0.55 | 0.54 | 0.66 | 0.84 | 0.38 | 0.44 | 0.46 | 0.33 | 0.22 | 0.32 | 0.31 | 0.36 | 0.45 | 0.61 | 0.90 | 0.67 | 0.66 | 0.68 | 0.68 |
| Consolidated Edison | 0.71 | 0.70 | 0.68 | 0.73 | 0.77 | 0.54 | 0.45 | 0.39 | 0.30 | 0.22 | 0.24 | 0.30 | 0.33 | 0.43 | 0.59 | 0.50 | 0.53 | 0.54 | 0.51 |
| Integrys Energy Group Inc. | 0.56 | 0.54 | 0.59 | 0.50 | 0.52 | 0.44 | 0.40 | 0.34 | 0.31 | 0.32 | 0.37 | 0.43 | 0.45 | 0.58 | 0.71 | 0.65 | 0.94 | 0.93 | 0.91 |
| Northwest Natural Gas | 0.47 | 0.46 | 0.46 | 0.42 | 0.58 | 0.64 | 0.45 | 0.41 | 0.37 | 0.26 | 0.20 | 0.33 | 0.36 | 0.43 | 0.83 | 0.57 | 0.50 | 0.54 | 0.54 |
| Piedmont Natural Gas | 0.56 | 0.62 | 0.59 | 0.51 | 0.54 | 0.67 | 0.52 | 0.42 | 0.43 | 0.39 | 0.31 | 0.42 | 0.52 | 0.57 | 0.72 | 0.37 | 0.46 | 0.49 | 0.54 |
| Southern Company | 0.67 | 0.65 | 0.59 | 0.69 | 0.61 | 0.43 | 0.40 | 0.30 | 0.09 | 0.03 | 0.02 | 0.01 | 0.00 | 0.29 | 0.55 | 0.58 | 0.56 | 0.57 | 0.53 |
| Vectren Corp. | 0.48 | 0.48 | 0.48 | 0.76 | 0.71 | 0.56 | 0.43 | 0.49 | 0.46 | 0.48 | 0.56 | 0.64 | 0.55 | 0.66 | 0.71 | 0.49 | 0.58 | 0.61 | 0.61 |
| WGL Holdings Inc. | 0.52 | 0.57 | 0.59 | 0.83 | 0.75 | 0.64 | 0.52 | 0.50 | 0.46 | 0.42 | 0.41 | 0.47 | 0.47 | 0.51 | 0.79 | 0.49 | 0.44 | 0.50 | 0.52 |
| Wisconsin Energy Corp. | 0.64 | 0.68 | 0.68 | 0.72 | 0.62 | 0.54 | 0.42 | 0.40 | 0.32 | 0.26 | 0.27 | 0.37 | 0.34 | 0.45 | 0.71 | 0.63 | 0.59 | 0.58 | 0.56 |
| Xcel Energy Inc. | 0.75 | 0.75 | 0.58 | 0.73 | 0.67 | 0.56 | 0.51 | 0.46 | 0.32 | 0.60 | 0.70 | 0.80 | 0.87 | 1.32 | 0.73 | 0.70 | 0.64 | 0.62 | 0.59 |
| **Mean** | 0.59 | 0.61 | 0.60 | 0.67 | 0.62 | 0.55 | 0.47 | 0.41 | 0.34 | 0.35 | 0.36 | 0.43 | 0.46 | 0.61 | 0.73 | 0.58 | 0.60 | 0.61 | 0.61 |
| **Median** | 0.56 | 0.61 | 0.59 | 0.70 | 0.62 | 0.55 | 0.45 | 0.40 | 0.32 | 0.36 | 0.34 | 0.42 | 0.46 | 0.57 | 0.71 | 0.58 | 0.59 | 0.60 | 0.58 |

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight*

**WEEKLY BETAS FOR SAMPLE OF U.S. UTILITIES**

**"Raw" Weekly Price Betas**
**Five Year Period Ending:**

| COMPANY | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 0.44 | 0.56 | 0.63 | 0.74 | 0.70 | 0.70 | 0.68 | 0.68 |
| Alliant Energy Corp. | 0.38 | 0.52 | 0.72 | 0.70 | 0.72 | 0.74 | 0.78 | 0.75 |
| Atmos Energy Corp. | 0.50 | 0.50 | 0.59 | 0.70 | 0.66 | 0.64 | 0.67 | 0.65 |
| Consolidated Edison | 0.25 | 0.29 | 0.39 | 0.48 | 0.50 | 0.50 | 0.51 | 0.47 |
| Integrys Energy Group Inc. | 0.29 | 0.42 | 0.50 | 0.63 | 0.64 | 0.82 | 0.83 | 0.80 |
| Northwest Natural Gas | 0.34 | 0.46 | 0.54 | 0.83 | 0.54 | 0.51 | 0.54 | 0.53 |
| Piedmont Natural Gas | 0.42 | 0.52 | 0.61 | 0.77 | 0.61 | 0.60 | 0.61 | 0.63 |
| Southern Company | 0.05 | 0.19 | 0.29 | 0.42 | 0.42 | 0.41 | 0.41 | 0.38 |
| Vectren Corp. | 0.73 | 0.55 | 0.74 | 0.79 | 0.60 | 0.64 | 0.64 | 0.63 |
| WGL Holdings Inc. | 0.43 | 0.52 | 0.63 | 0.78 | 0.68 | 0.62 | 0.61 | 0.61 |
| Wisconsin Energy Corp. | 0.36 | 0.41 | 0.48 | 0.67 | 0.58 | 0.52 | 0.52 | 0.49 |
| Xcel Energy Inc. | 0.54 | 0.68 | 0.81 | 0.60 | 0.55 | 0.53 | 0.53 | 0.51 |
| **Mean** | **0.39** | **0.47** | **0.58** | **0.68** | **0.60** | **0.60** | **0.61** | **0.59** |
| **Median** | **0.40** | **0.51** | **0.60** | **0.70** | **0.61** | **0.61** | **0.61** | **0.62** |

**Adjusted Betas [1/]**
**Five Year Period Ending:**

| COMPANY | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 0.62 | 0.71 | 0.75 | 0.82 | 0.80 | 0.80 | 0.79 | 0.79 |
| Alliant Energy Corp. | 0.58 | 0.68 | 0.81 | 0.80 | 0.81 | 0.83 | 0.85 | 0.83 |
| Atmos Energy Corp. | 0.66 | 0.66 | 0.72 | 0.80 | 0.78 | 0.76 | 0.78 | 0.77 |
| Consolidated Edison | 0.50 | 0.53 | 0.59 | 0.65 | 0.66 | 0.66 | 0.67 | 0.64 |
| Integrys Energy Group Inc. | 0.53 | 0.61 | 0.66 | 0.75 | 0.76 | 0.88 | 0.89 | 0.86 |
| Northwest Natural Gas | 0.56 | 0.64 | 0.69 | 0.89 | 0.69 | 0.67 | 0.69 | 0.68 |
| Piedmont Natural Gas | 0.61 | 0.68 | 0.74 | 0.85 | 0.74 | 0.73 | 0.74 | 0.75 |
| Southern Company | 0.37 | 0.46 | 0.52 | 0.61 | 0.61 | 0.60 | 0.60 | 0.59 |
| Vectren Corp. | 0.82 | 0.70 | 0.83 | 0.86 | 0.73 | 0.76 | 0.76 | 0.75 |
| WGL Holdings Inc. | 0.62 | 0.68 | 0.75 | 0.85 | 0.78 | 0.74 | 0.74 | 0.74 |
| Wisconsin Energy Corp. | 0.57 | 0.60 | 0.65 | 0.78 | 0.72 | 0.68 | 0.68 | 0.66 |
| Xcel Energy Inc. | 0.69 | 0.79 | 0.87 | 0.73 | 0.70 | 0.68 | 0.69 | 0.67 |
| **Mean** | **0.59** | **0.64** | **0.72** | **0.78** | **0.73** | **0.73** | **0.74** | **0.73** |
| **Median** | **0.60** | **0.67** | **0.73** | **0.80** | **0.74** | **0.74** | **0.74** | **0.74** |

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: www.yahoo.com

## HISTORICAL VALUE LINE BETAS FOR SAMPLE OF U.S. UTILITIES

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 0.75 | 0.75 | 0.65 | 0.65 | 0.60 | 0.60 | 0.75 | 0.75 | 0.80 | 0.90 | 0.95 | 0.85 | 0.75 | 0.75 | 0.75 | 0.75 |
| Alliant Energy Corp. | 0.60 | 0.55 | nmf | nmf | 0.55 | 0.55 | 0.65 | 0.70 | 0.80 | 0.85 | 0.95 | 0.80 | 0.70 | 0.70 | 0.70 | 0.75 |
| Atmos Energy Corp. | 0.65 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.60 | 0.65 | 0.70 | 0.70 | 0.80 | 0.85 | 0.65 | 0.65 | 0.65 | 0.70 |
| Consolidated Edison | 0.75 | 0.75 | 0.60 | 0.50 | 0.55 | 0.50 | 0.55 | 0.60 | 0.60 | 0.60 | 0.75 | 0.75 | 0.65 | 0.65 | 0.65 | 0.60 |
| Integrys Energy Group Inc. | 0.65 | 0.65 | 0.65 | 0.50 | 0.55 | 0.55 | 0.60 | 0.70 | 0.75 | 0.75 | 0.85 | 0.80 | 0.70 | 0.95 | 0.90 | 0.90 |
| Northwest Natural Gas | 0.45 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.65 | 0.70 | 0.75 | 0.90 | 0.60 | 0.60 | 0.60 | 0.60 |
| Piedmont Natural Gas | 0.65 | 0.60 | 0.55 | 0.55 | 0.60 | 0.60 | 0.70 | 0.70 | 0.75 | 0.75 | 0.80 | 0.85 | 0.70 | 0.65 | 0.65 | 0.70 |
| Southern Company 1/ | 0.70 | 0.70 | 0.50 | 0.45 | 0.50 | nmf | nmf | 0.60 | 0.65 | 0.65 | 0.70 | 0.70 | 0.55 | 0.55 | 0.55 | 0.55 |
| Vectren Corp. | 0.70 | 0.75 | 0.75 | 0.55 | nmf | nmf | 0.70 | 0.75 | 0.75 | 0.80 | 0.90 | 0.90 | 0.85 | 0.75 | 0.70 | 0.70 |
| WGL Holdings Inc. | 0.70 | 0.75 | 0.60 | 0.60 | 0.60 | 0.60 | 0.65 | 0.70 | 0.75 | 0.80 | 0.85 | 0.85 | 0.75 | 0.65 | 0.65 | 0.65 |
| Wisconsin Energy Corp. | 0.70 | 0.70 | 0.65 | 0.45 | 0.50 | 0.50 | 0.55 | 0.60 | 0.70 | 0.70 | 0.80 | 0.85 | 0.65 | 0.65 | 0.65 | 0.65 |
| Xcel Energy Inc. | na | na | na | na | nmf | nmf | 0.60 | 0.70 | 0.80 | 0.80 | 0.90 | 1.05 | 0.75 | 0.65 | 0.65 | 0.65 |
| **Mean** | **0.66** | **0.67** | **0.61** | **0.54** | **0.56** | **0.56** | **0.63** | **0.67** | **0.73** | **0.75** | **0.83** | **0.85** | **0.69** | **0.68** | **0.68** | **0.68** |
| **Median** | **0.70** | **0.70** | **0.60** | **0.55** | **0.55** | **0.55** | **0.60** | **0.70** | **0.75** | **0.75** | **0.83** | **0.85** | **0.70** | **0.65** | **0.65** | **0.68** |

1/ 1996 number is from 1st quarter 1997.

Source: Value Line fourth quarter issues

**INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. UTILITIES**

| | Value Line | | | | | | | | | S & P | | Moody's |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Safety | Forecast Common Equity Ratio 2015-2017 | Forecast Return On Average Common Equity 2015-2017 | Dividend Payout Forecast 2015-2017 | 2012Q2 Beta | "Raw" Weekly Betas[1/] | Adjusted Weekly Betas | Common Equity Ratio 2011Q4 Trailing Four Quarters | 2009-2011 Average Earned Returns | Business Risk Profile | Debt Rating | Debt Rating[2/] |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| AGL Resources Inc. | 1 | 57.0% | 12.3% | 48.8% | 0.75 | 0.64 | 0.76 | 43.4% | 10.9% | Excellent | BBB+ | Baa1 |
| Alliant Energy Corp. | 2 | 49.5% | 11.4% | 61.1% | 0.75 | 0.68 | 0.78 | 50.1% | 8.1% | Excellent | BBB+ | Baa1 |
| Atmos Energy Corp. | 2 | 51.0% | 7.9% | 54.8% | 0.70 | 0.61 | 0.74 | 49.7% | 9.3% | Excellent | BBB+ | Baa1 |
| Consolidated Edison | 1 | 52.5% | 9.3% | 62.0% | 0.60 | 0.41 | 0.61 | 50.8% | 9.1% | Excellent | A- | Baa1 |
| Integrys Energy Group Inc. | 2 | 56.0% | 9.8% | 65.9% | 0.90 | 0.72 | 0.81 | 55.2% | 4.3% | Excellent | A- | Baa1 |
| Northwest Natural Gas | 1 | 63.0% | 10.9% | 53.9% | 0.60 | 0.47 | 0.65 | 47.0% | 10.5% | Excellent | A+ | A3 |
| Piedmont Natural Gas | 2 | 50.0% | 13.2% | 71.1% | 0.70 | 0.57 | 0.72 | 51.4% | 13.4% | Excellent | A | A3 |
| Southern Company | 1 | 45.5% | 12.6% | 69.2% | 0.55 | 0.32 | 0.54 | 44.3% | 12.5% | Excellent | A | Baa1 |
| Vectren Corp. | 2 | 48.0% | 12.2% | 64.0% | 0.70 | 0.59 | 0.72 | 45.2% | 9.6% | Excellent | A- | A3 |
| WGL Holdings Inc. | 1 | 70.5% | 10.0% | 62.5% | 0.65 | 0.55 | 0.70 | 62.1% | 10.3% | Excellent | A+ | A2 |
| Wisconsin Energy Corp. | 1 | 46.5% | 13.9% | 65.5% | 0.65 | 0.44 | 0.63 | 47.8% | 12.3% | Excellent | A- | A3 |
| Xcel Energy Inc. | 2 | 50.0% | 10.6% | 60.0% | 0.65 | 0.45 | 0.63 | 45.3% | 9.8% | Excellent | A- | Baa1 |
| **Mean** | **1.5** | **53.3%** | **11.2%** | **61.6%** | **0.68** | **0.54** | 0.69 | **49.3%** | **10.0%** | **Excellent** | **A-** | **Baa1** |
| **Median** | **1.5** | **50.5%** | **11.1%** | **62.2%** | **0.68** | **0.56** | 0.71 | **48.7%** | **10.1%** | **Excellent** | **A-** | **Baa1** |

[1/] "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending May 21, 2012).

[2/] Rating for Vectren Corp. is for Vectren Utility Holdings. Rating for WGL Holdings is Washington Gas Light.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Utilities, Strongest To Weakest* (April 20, 2012); Standard and Poor's Research Insight; Value Line (February, March, and May 2012); *Value Line Index*, May 11, 2012; and www.yahoo.com.

**EQUITY RETURN AWARDS AND COMMON EQUITY RATIOS ADOPTED FOR THE SAMPLE OF U.S. UTILITIES**
**2009-2012**

| Parent | Subsidiary (1) | Service (2) | State (3) | Decision Date (4) | Allowed ROE (5) | Allowed Common Equity Ratio (6) |
|---|---|---|---|---|---|---|
| AGL Resources Inc. | Atlanta Gas Light Co. | Gas | GA | 11/3/2010 | 10.75 | 51.00 |
| | Northern Illinois Gas Co. | Gas | IL | 3/25/2009 | 10.17 | 51.07 |
| | Pivotal Utility Holdings Inc. | Gas | NJ | 12/17/2009 | 10.30 | 47.89 |
| | Chattanooga Gas Co. | Gas | TN | 5/24/2010 | 10.05 | 46.06 |
| | Virginia Natural Gas Inc. | Gas | VA | 12/20/2011 | 10.00 | 45.36 |
| Alliant Energy Corp. | Interstate P&L | Electric | IA | 12/15/2010 | 10.44 | 44.24 |
| | Interstate P&L | Electric | MN | 8/12/2011 | 10.35 | 47.74 |
| | Wisconsin P&L | Electric | WI | 6/15/2012 | 10.40 | 49.31 |
| | Wisconsin P&L | Gas | WI | 6/15/2012 | 10.40 | 49.31 |
| Atmos Energy Corp. | Atmos Energy Corp. | Gas | GA | 3/31/2010 | 10.70 | 47.70 |
| | Atmos Energy Corp. | Gas | TN | 3/9/2009 | 10.30 | 48.12 |
| | Atmos Energy Corp. | Gas | TX | 1/26/2010 | 10.40 | 48.91 |
| Consolidated Edison | Rockland Electric Co. | Electric | NJ | 5/12/2010 | 10.30 | 49.85 |
| | Consolidated Edison Co. of NY | Gas | NY | 9/16/2010 | 9.60 | 48.00 |
| | Consolidated Edison Co. of NY | Electric | NY | 3/25/2010 | 10.15 | 48.00 |
| | Orange & Rockland Utilities Inc. | Electric | NY | 6/14/2012 | 9.40 | 48.00 |
| | Orange & Rockland Utilities Inc. | Gas | NY | 10/16/2009 | 10.40 | 48.00 |
| Integrys Energy Group Inc. | North Shore Gas Co. | Gas | IL | 1/10/2012 | 9.45 | 50.00 |
| | Peoples Gas Light & Coke Co. | Gas | IL | 1/10/2012 | 9.45 | 49.00 |
| | Michigan Gas Utilities Corp. | Gas | MI | 12/16/2009 | 10.75 | 47.27 |
| | Upper Peninsula Power | Electric | MI | 12/20/2011 | 10.20 | 54.90 |
| | Minnesota Energy Resources | Gas | MN | 5/24/2012 | 9.70 | NA |
| | Wisconsin Public Service | Electric | WI | 1/13/2011 | 10.30 | 51.65 |
| | Wisconsin Public Service | Gas | WI | 1/13/2011 | 10.30 | 51.65 |
| Piedmont Natural Gas Co. | Piedmont Natural Gas Co. | Gas | TN | 1/23/2012 | 10.20 | 52.71 |
| Southern Co. | Gulf Power Co. | Electric | FL | 2/27/2012 | 10.25 | 46.26 |
| | Georgia Power | Electric | GA | 12/29/2010 | 11.15 | 51.67 |
| Vectren Corp. | Southern Indiana G&E | Electric | IN | 4/27/2011 | 10.40 | 49.93 |
| WGL Holdings Inc. | Washington Gas Light Co. | Gas | MD | 11/14/2011 | 9.60 | 57.88 |
| | Washington Gas Light Co. | Gas | VA | 4/21/2011 | 10.00 | 55.70 |
| Wisconsin Energy Corp. | Wisconsin Electric Power | Electric | MI | 6/26/2012 | 10.10 | 43.51 |
| | Wisconsin Electric Power | Electric | WI | 12/18/2009 | 10.40 | 53.02 |
| | Wisconsin Electric Power | Gas | WI | 12/18/2009 | 10.40 | 53.02 |
| | Wisconsin Gas LLC | Gas | WI | 12/18/2009 | 10.50 | 46.62 |
| Xcel Energy Inc. | Public Service of CO | Electric | CO | 4/26/2012 | 10.00 | 56.00 |
| | Public Service of CO | Gas | CO | 9/1/2011 | 10.10 | 56.00 |
| | Northern States Power-MN | Electric | MN | 3/29/2012 | 10.37 | 52.56 |
| | Northern States Power-MN | Gas | MN | 12/6/2010 | 10.09 | 52.46 |
| | Northern States Power-MN | Electric | ND | 2/29/2012 | 10.40 | 51.77 |
| | Northern States Power-MN | Electric | SD | 6/19/2012 | 9.25 | 53.04 |
| | Southwestern Public Service | Electric | TX | 3/25/2011 | NA | NA [1/] |
| | Northern States Power-WI | Gas | WI | 12/22/2011 | 10.40 | 52.59 |
| | Northern States Power-WI | Electric | WI | 12/22/2011 | 10.40 | 52.59 |

| | ROE | Equity Ratio |
|---|---|---|
| **2009-2012:** | | |
| **Mean** | **10.20** | **50.25** |
| **Median** | **10.30** | **49.93** |
| **2011-2012:** | | |
| **Mean** | **10.06** | **51.19** |
| **Median** | **10.20** | **51.65** |

[1/] A 10% ROE and 51% equity ratio are to be used, per the settlement, solely for purposes of any Transmission Cost Recovery Factor filings before the next PUC rate case and for AFUDC purposes only.

Source: Regulatory Research Associates and various regulatory decisions.

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES**
**CONSTANT GROWTH DCF MODEL**
**(Annual Averages of Monthly Data)**

| Year | Expected Dividend Yield[1/] (1) | I/B/E/S EPS Growth Forecast (2) | DCF Cost of Equity (3) | Long-Term Treasury Yield (4) | Equity Risk Premium (5) | Moody's Spread[2/] (6) |
|---|---|---|---|---|---|---|
| 1998 | 5.0 | 4.3 | 9.3 | 5.5 | 3.8 | 1.5 |
| 1999 | 5.5 | 4.7 | 10.2 | 5.9 | 4.3 | 1.7 |
| 2000 | 6.1 | 5.0 | 11.1 | 5.9 | 5.2 | 2.4 |
| 2001 | 5.4 | 5.1 | 10.5 | 5.5 | 5.0 | 2.3 |
| 2002 | 5.3 | 5.7 | 10.9 | 5.4 | 5.5 | 1.9 |
| 2003 | 5.1 | 5.0 | 10.0 | 5.0 | 5.0 | 1.5 |
| 2004 | 4.7 | 4.4 | 9.1 | 5.1 | 4.0 | 1.0 |
| 2005 | 4.3 | 4.4 | 8.7 | 4.5 | 4.2 | 1.1 |
| 2006 | 4.5 | 4.7 | 9.2 | 4.9 | 4.3 | 1.2 |
| 2007 | 4.3 | 4.9 | 9.2 | 4.8 | 4.4 | 1.3 |
| 2008 | 4.8 | 5.4 | 10.3 | 4.2 | 6.0 | 2.3 |
| 2009 | 5.5 | 5.3 | 10.9 | 4.1 | 6.8 | 1.9 |
| 2010 | 4.9 | 5.0 | 9.9 | 4.2 | 5.7 | 1.2 |
| 2011 | 4.4 | 5.2 | 9.6 | 3.9 | 5.8 | 1.1 |
| 2012 Q1 | 4.3 | 4.7 | 9.0 | 3.1 | 5.9 | 1.2 |
| **Means for Long Treasury Yields:** | | | | | | |
| **Below 4.0%** | **4.8** | **5.2** | **9.9** | **3.4** | **6.5** | **1.8** |
| **4.0-4.99%** | **4.7** | **5.0** | **9.7** | **4.6** | **5.1** | **1.4** |
| **Below 5.0%** | **4.7** | **5.0** | **9.7** | **4.4** | **5.4** | **1.5** |
| **5.0-5.99%** | **5.2** | **4.9** | **10.1** | **5.5** | **4.6** | **1.7** |
| **6.0% and above** | **6.0** | **4.8** | **10.8** | **6.2** | **4.6** | **1.9** |
| **Means:** | | | | | | |
| **1998 - 2012Q1** | **5.0** | **4.9** | **9.9** | **4.9** | **5.0** | **1.6** |

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).

[2/] Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES**
**CONSTANT GROWTH DCF MODEL**

**Regression Analysis Results 1998-2012Q1**

## EQUATION 1:

Equity Risk Premium = 8.76 - 0.77 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -9.41
$R^2$ = 34%

**Equity Risk Premium at Long-Term Government Bond Yield of 4.00%** = **5.7%**

**ROE at Long-Term Government Bond Yield of 4.00%** = **9.7%**

## EQUATION 2:

Equity Risk Premium = 7.55 - 0.86 (30-Year Treasury Yield) + 1.06 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -15.11
Spread = 13.42

$R^2$ = 68%

**Equity Risk Premium at Long-term Government Bond Yield of 4.00% and Spread of 1.35%** = **5.5%**

**ROE at Long-Term Government Bond Yield of 4.00% and Spread of 1.35%** = **9.5%**

## EQUATION 3:

Equity Risk Premium = 6.86 - 0.53 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -10.12
$R^2$ = 38%

**Equity Risk Premium at A-rated Utility Bond Yield of 5.35%** = **4.0%**

**ROE at A-rated Utility Bond Yield of 5.35%** = **9.4%**

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. $R^2$ is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES**
**THREE STAGE MODEL**

**(Annual Averages of Monthly Data)**

| Year | Dividend Yield (1) | Implied Growth Rate (2) | DCF Cost of Equity[1/] (3) | Long-Term Treasury Yield (4) | Equity Risk Premium (5) | Moody's Spread[2/] (6) |
|---|---|---|---|---|---|---|
| 1998 | 4.8 | 4.8 | 9.6 | 5.5 | 4.1 | 1.5 |
| 1999 | 5.3 | 4.9 | 10.2 | 5.9 | 4.2 | 1.7 |
| 2000 | 5.8 | 5.4 | 11.1 | 5.9 | 5.3 | 2.4 |
| 2001 | 5.1 | 5.6 | 10.7 | 5.5 | 5.3 | 2.3 |
| 2002 | 5.0 | 5.8 | 10.7 | 5.4 | 5.3 | 1.9 |
| 2003 | 4.8 | 5.6 | 10.4 | 5.0 | 5.4 | 1.5 |
| 2004 | 4.5 | 5.5 | 10.0 | 5.1 | 4.9 | 1.0 |
| 2005 | 4.1 | 5.4 | 9.5 | 4.5 | 5.0 | 1.1 |
| 2006 | 4.3 | 5.5 | 9.8 | 4.9 | 4.9 | 1.2 |
| 2007 | 4.1 | 5.3 | 9.4 | 4.8 | 4.6 | 1.3 |
| 2008 | 4.6 | 5.3 | 9.9 | 4.2 | 5.7 | 2.3 |
| 2009 | 5.2 | 5.4 | 10.6 | 4.1 | 6.5 | 1.9 |
| 2010 | 4.6 | 5.2 | 9.8 | 4.2 | 5.6 | 1.2 |
| 2011 | 4.2 | 5.2 | 9.4 | 3.9 | 5.5 | 1.1 |
| 2012 Q1 | 4.1 | 5.0 | 9.0 | 3.1 | 5.9 | 1.2 |
| **Means for Long Treasury Yields:** | | | | | | |
| **Below 4.0%** | **4.5** | **5.2** | **9.8** | **3.4** | **6.4** | **1.8** |
| **4.0-4.99%** | **4.5** | **5.4** | **9.9** | **4.6** | **5.3** | **1.4** |
| **Below 5.0%** | **4.5** | **5.3** | **9.8** | **4.4** | **5.5** | **1.5** |
| **5.0-5.99%** | **5.0** | **5.4** | **10.3** | **5.5** | **4.8** | **1.7** |
| **6.0% and above** | **5.7** | **5.0** | **10.7** | **6.2** | **4.5** | **1.9** |
| **Means:** | | | | | | |
| **1998 - 2012Q1** | **4.7** | **5.3** | **10.1** | **4.9** | **5.2** | **1.6** |

[1/] Internal Rate of Return: Stage 1 growth rate, I/B/E/S EPS growth forecast, applies for first 5 years; Stage 2 growth rate, average of Stage 1 and 3 growth rates, applies for years 6-10; Stage 3 growth, equal to the forecast nominal GDP growth rate, applies thereafter.

[2/] Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES**
**THREE STAGE MODEL**

**Regression Analysis Results 1998-2012 Q1**

## EQUATION 1:

Equity Risk Premium = 8.33 - 0.65 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -11.33

$R^2$ = 43%

**Equity Risk Premium at Long-Term Government Bond Yield of 4.00%** = **5.7%**

**ROE at Long-Term Government Bond Yield of 4.00%** = **9.7%**

## EQUATION 2:

Equity Risk Premium = 7.56 - 0.71 (30-Year Treasury Yield) + 0.68 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -16.35

Spread = 11.36

$R^2$ = 68%

**Equity Risk Premium at Long-term Government Bond Yield of 4.00% and Spread of 1.35%** = **5.6%**

**ROE at Long-Term Government Bond Yield of 4.00% and Spread of 1.35%** = **9.6%**

## EQUATION 3:

Equity Risk Premium = 7.27 - 0.57 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -16.26

$R^2$ = 61%

**Equity Risk Premium at A-rated Utility Bond Yield of 5.35%** = **4.2%**

**ROE at A-rated Utility Bond Yield of 5.35%** = **9.6%**

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. $R^2$ is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

## APPROVED U.S. ELECTRIC AND GAS UTILITY ROES, BOND YIELDS AND SPREADS

| | Approved Electric and Gas ROEs | Moody's A-Rated Utility Bond Yield | 30-Year Treasury Yield | A-Rated Utility/ Treasury Yield Spread | | Approved Electric and Gas ROEs | Moody's A-Rated Utility Bond Yield | 30-Year Treasury Yield | A-Rated Utility/ Treasury Yield Spread |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | | (5) | (6) | (7) | (8) |
| 1997 Q3 | | 7.49 | 6.44 | 1.05 | 2005 Q1 | 10.54 | 5.72 | 4.70 | 1.02 |
| 1997 Q4 | | 7.25 | 6.04 | 1.21 | 2005 Q2 | 10.25 | 5.43 | 4.36 | 1.07 |
| 1998 Q1 | 11.31 | 7.11 | 5.89 | 1.21 | 2005 Q3 | 10.63 | 5.49 | 4.39 | 1.10 |
| 1998 Q2 | 11.58 | 7.12 | 5.79 | 1.32 | 2005 Q4 | 10.55 | 5.82 | 4.63 | 1.18 |
| 1998 Q3 | 11.57 | 6.99 | 5.33 | 1.65 | 2006 Q1 | 10.55 | 5.92 | 4.70 | 1.22 |
| 1998 Q4 | 11.75 | 6.97 | 5.11 | 1.86 | 2006 Q2 | 10.64 | 6.41 | 5.19 | 1.22 |
| 1999 Q1 | 10.68 | 7.11 | 5.43 | 1.68 | 2006 Q3 | 10.18 | 6.09 | 4.91 | 1.18 |
| 1999 Q2 | 10.89 | 7.48 | 5.83 | 1.64 | 2006 Q4 | 10.31 | 5.82 | 4.70 | 1.13 |
| 1999 Q3 | 10.63 | 7.85 | 6.08 | 1.77 | 2007 Q1 | 10.36 | 5.92 | 4.82 | 1.10 |
| 1999 Q4 | 10.76 | 8.05 | 6.31 | 1.74 | 2007 Q2 | 10.23 | 6.08 | 4.98 | 1.10 |
| 2000 Q1 | 11.00 | 8.29 | 6.16 | 2.13 | 2007 Q3 | 10.03 | 6.19 | 4.86 | 1.33 |
| 2000 Q2 | 11.09 | 8.45 | 5.96 | 2.49 | 2007 Q4 | 10.42 | 6.05 | 4.53 | 1.52 |
| 2000 Q3 | 11.43 | 8.20 | 5.78 | 2.42 | 2008 Q1 | 10.42 | 6.16 | 4.35 | 1.81 |
| 2000 Q4 | 12.25 | 8.03 | 5.62 | 2.41 | 2008 Q2 | 10.46 | 6.30 | 4.58 | 1.72 |
| 2001 Q1 | 11.23 | 7.74 | 5.45 | 2.29 | 2008 Q3 | 10.48 | 6.58 | 4.44 | 2.14 |
| 2001 Q2 | 10.84 | 7.93 | 5.77 | 2.16 | 2008 Q4 | 10.34 | 7.13 | 3.50 | 3.63 |
| 2001 Q3 | 10.78 | 7.64 | 5.44 | 2.20 | 2009 Q1 | 10.27 | 6.44 | 3.62 | 2.82 |
| 2001 Q4 | 11.29 | 7.61 | 5.21 | 2.39 | 2009 Q2 | 10.35 | 6.35 | 4.24 | 2.11 |
| 2002 Q1 | 10.80 | 7.63 | 5.66 | 1.98 | 2009 Q3 | 10.23 | 5.54 | 4.17 | 1.37 |
| 2002 Q2 | 11.50 | 7.48 | 5.72 | 1.76 | 2009 Q4 | 10.41 | 5.65 | 4.35 | 1.30 |
| 2002 Q3 | 11.25 | 7.14 | 5.13 | 2.01 | 2010 Q1 | 10.51 | 5.80 | 4.59 | 1.20 |
| 2002 Q4 | 10.94 | 7.12 | 5.11 | 2.01 | 2010 Q2 | 10.04 | 5.46 | 4.22 | 1.24 |
| 2003 Q1 | 11.43 | 6.84 | 4.93 | 1.91 | 2010 Q3 | 10.17 | 4.96 | 3.73 | 1.23 |
| 2003 Q2 | 11.26 | 6.37 | 4.71 | 1.67 | 2010 Q4 | 10.21 | 5.31 | 4.15 | 1.16 |
| 2003 Q3 | 10.28 | 6.61 | 5.28 | 1.33 | 2011 Q1 | 10.26 | 5.56 | 4.53 | 1.03 |
| 2003 Q4 | 10.93 | 6.34 | 5.22 | 1.13 | 2011 Q2 | 10.04 | 5.37 | 4.33 | 1.04 |
| 2004 Q1 | 11.06 | 6.06 | 4.96 | 1.09 | 2011 Q3 | 9.92 | 4.74 | 3.54 | 1.20 |
| 2004 Q2 | 10.47 | 6.45 | 5.39 | 1.05 | 2011 Q4 | 10.22 | 4.35 | 3.04 | 1.31 |
| 2004 Q3 | 10.36 | 6.11 | 5.08 | 1.03 | 2012 Q1 1/ | 10.02 | 4.35 | 3.12 | 1.23 |
| 2004 Q4 | 10.80 | 5.95 | 4.93 | 1.01 | | | | | |

1/ The first quarter 2012 average awarded ROE reported by RRA excluding ROEs granted for regulated generation investments.

Sources: www.federalreserve.gov; www.moodys.com; Regulatory Research Associates at www.snl.com; www.ustreas.gov

**APPROVED ROES FOR U.S. ELECTRIC AND GAS UTILITIES**
**(ANNUAL AVERAGES OF MONTHLY DATA)**

**Regression Analysis Results 1998-2012Q1**

**EQUATION 1:**

Equity Risk Premium = 8.00 - 0.46 (6 Months Lagged 30-Year Treasury Yield)

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -7.17
$R^2$ = 48%

**EQUATION 2:**

Equity Risk Premium = 7.63 - 0.47 (6 Months Lagged 30-Year Treasury Yield) + 0.27 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -8.06
Spread = 3.53

$R^2$ = 58%

**EQUATION 3:**

Equity Risk Premium = 7.87 - 0.57 (6 Months Lagged Moody's A-Rated)

t-statistics:
6 Months Lagged Moody's A-Rated = -12.07

$R^2$ = 73%

**HISTORIC UTILITY EQUITY RISK PREMIUMS**
**(Arithmetic Averages)**

**Canada**
**(1956-2011)**

| Utilities Index Return | Bond Total Return | Risk Premium |
|---|---|---|
| 12.1 | 7.9 | 4.2 |
| Utilities Index Return | Bond Income Return | Risk Premium |
| 12.1 | 7.3 | 4.8 |

**United States**
**(1947-2011)**

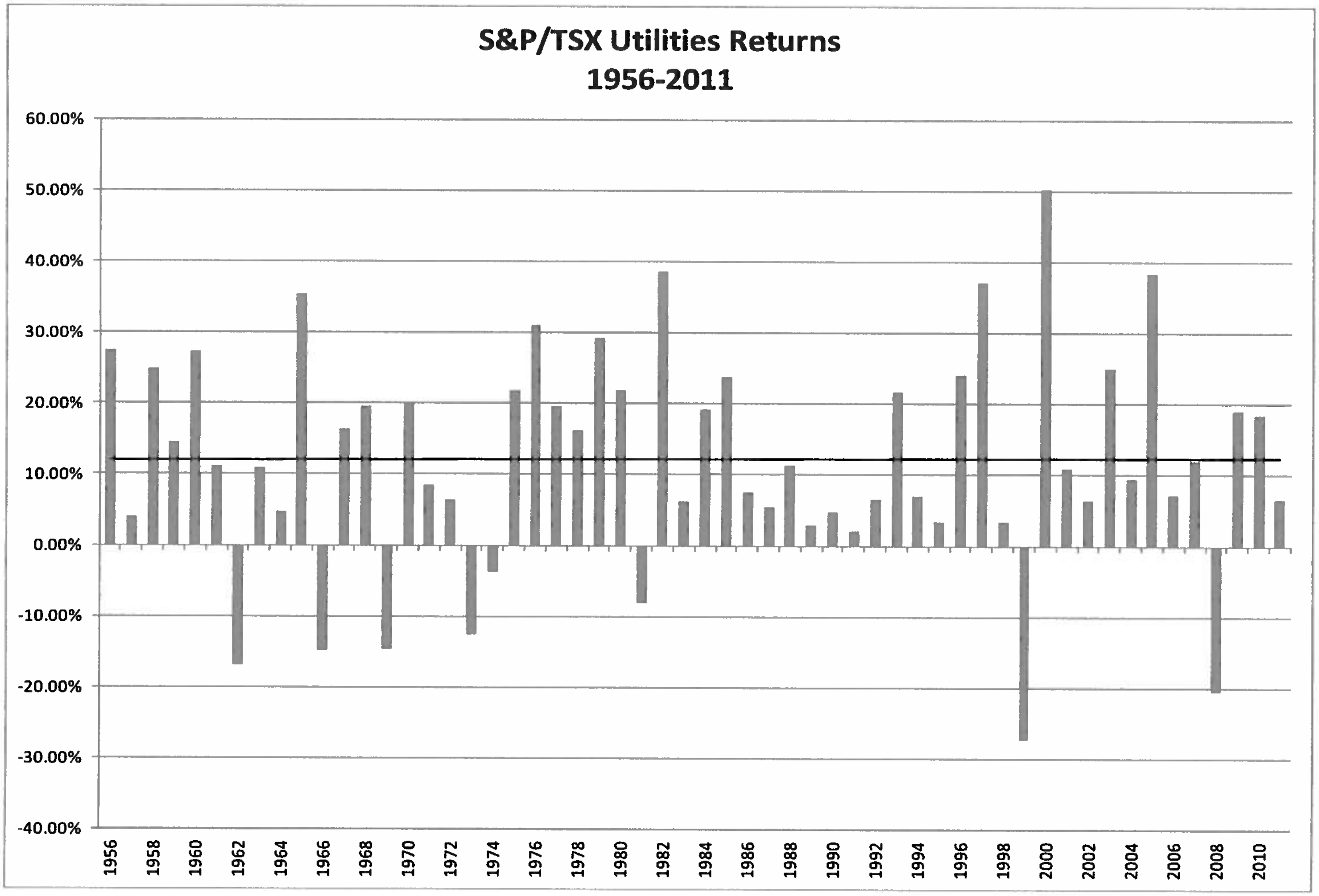
| S&P/Moody's Electric Index Return | Bond Total Return | Risk Premium |
|---|---|---|
| 11.0 | 6.6 | 4.4 |
| S&P/Moody's Electric Index Return | Bond Income Return | Risk Premium |
| 11.0 | 5.9 | 5.1 |
| S&P / Moody's Gas Distribution Index Return | Bond Total Return | Risk Premium |
| 11.9 | 6.6 | 5.3 |
| S&P / Moody's Gas Distribution Index Return | Bond Income Return | Risk Premium |
| 11.9 | 5.9 | 6.0 |

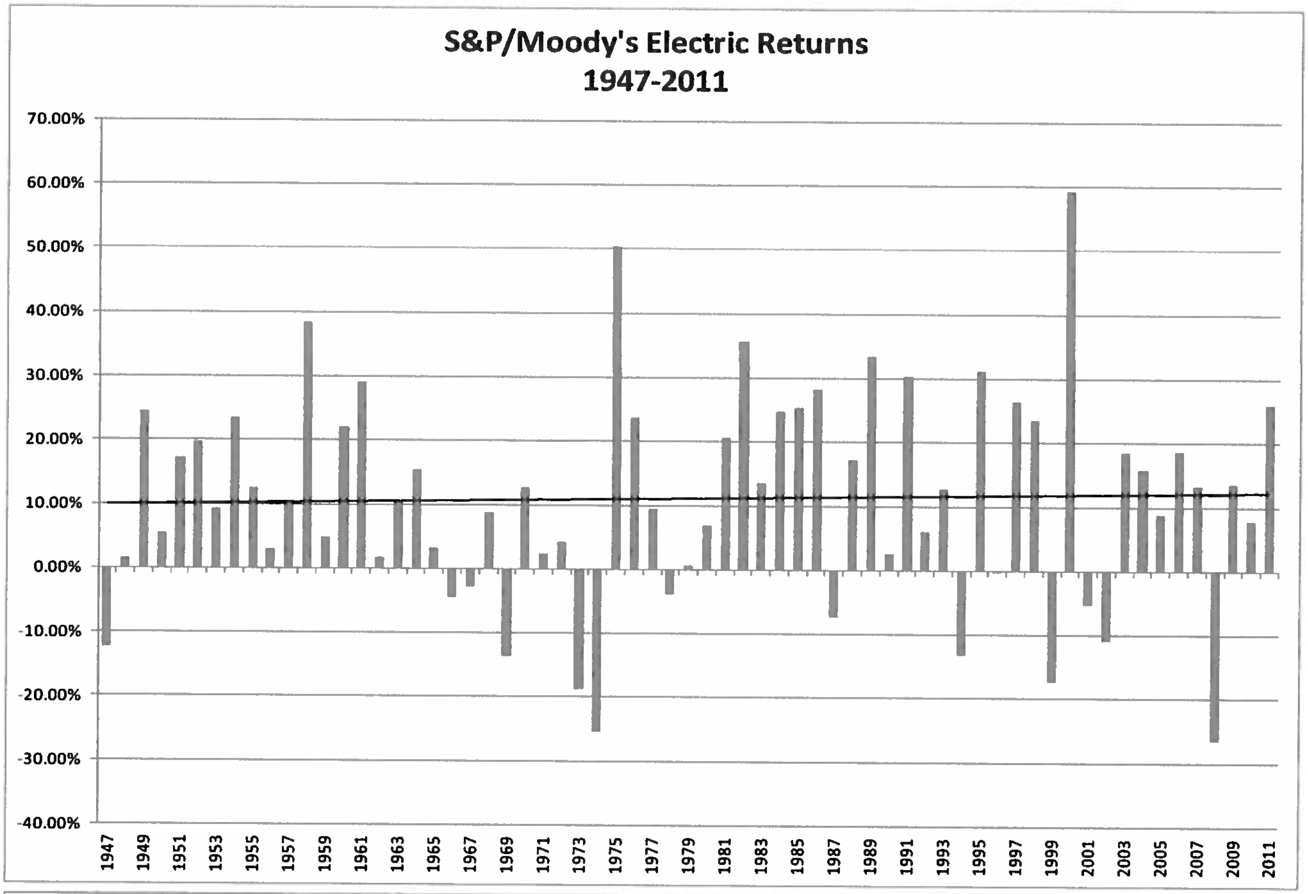
Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2011.

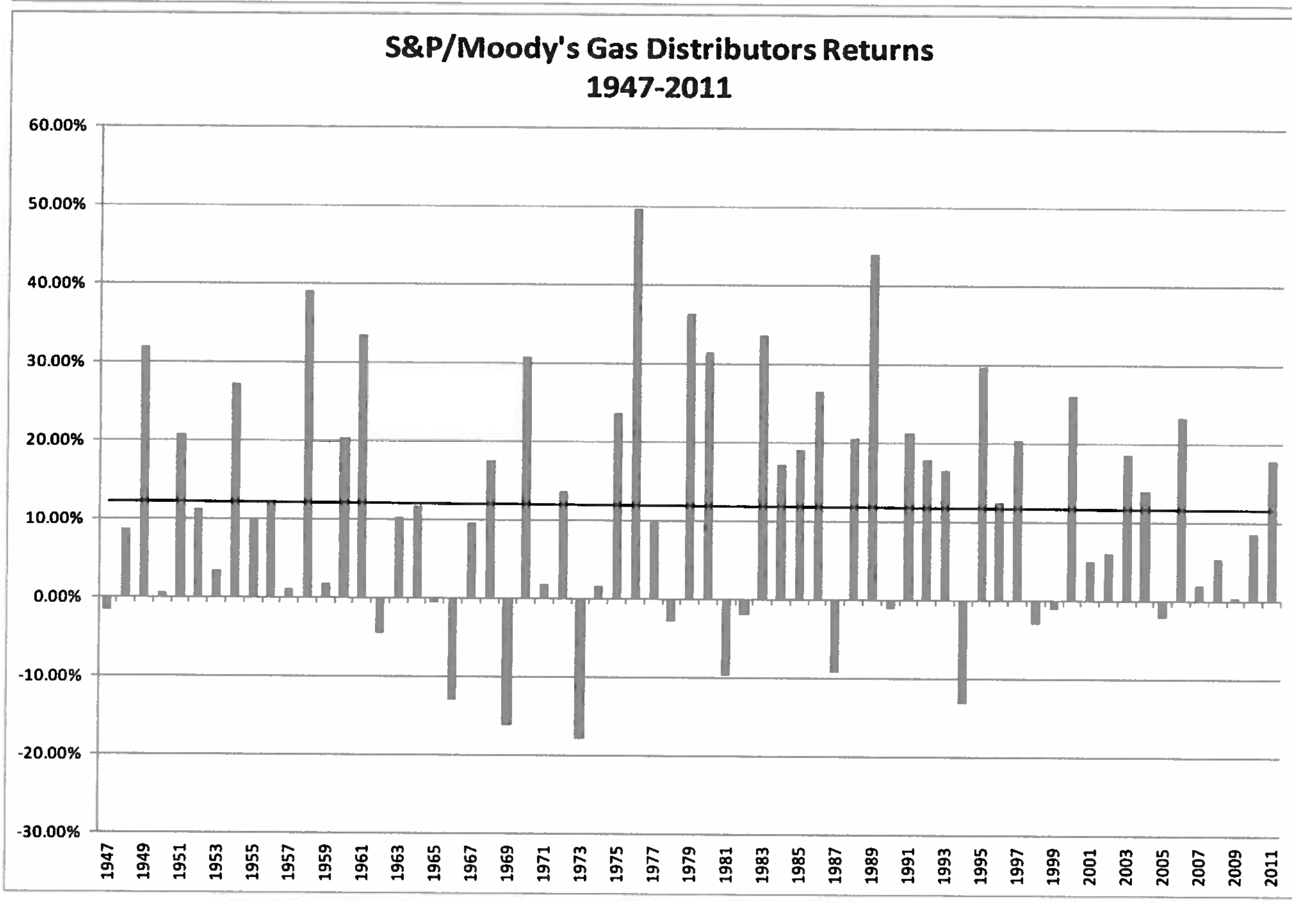
The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2011 data were estimated using simple average of the prices and dividends for the utilities, and their successors, included in Moody's Electric Index as of the end of 2001.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2011 returns were estimated using simple averages of the prices and dividends for the utilities, and their successors, that were included in Moody's Gas Index as of the end of 2001.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*; www.standardandpoors.com; *TSX Review.*


S&P/TSX Utilities Returns
1956-2011
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1956
1958
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010


S&P/Moody's Electric Returns
1947-2011
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1947
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011


S&P/Moody's Gas Distributors Returns
1947-2011
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
1947
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011

## DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
## (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

| Company | Annualized Last Paid Dividend | Average Daily Close Prices 3/16-6/15/2012 | Expected Dividend Yield [1/] | Analyst Forecast Long-Term Growth Rates: Bloomberg | Reuters | Value Line | Zacks | Average of All EPS Estimates | DCF Cost of Equity [2/] |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| AGL Resources Inc. | 1.84 | 38.25 | 5.0 | 4.0 | 4.4 | 5.5 | 4.3 | 4.6 | 9.6 |
| Alliant Energy Corp. | 1.80 | 43.87 | 4.3 | 5.8 | 5.9 | 6.0 | 6.2 | 6.0 | 10.3 |
| Atmos Energy Corp. | 1.38 | 32.25 | 4.5 | 6.0 | 5.4 | 4.0 | 4.8 | 5.0 | 9.5 |
| Consolidated Edison | 2.42 | 59.15 | 4.2 | 3.4 | 3.4 | 4.0 | 3.6 | 3.6 | 7.8 |
| Integrys Energy Group Inc. | 2.72 | 53.62 | 5.4 | 4.3 | 7.2 | 7.0 | 4.5 | 5.8 | 11.1 |
| Northwest Natural Gas | 1.78 | 45.63 | 4.1 | 3.4 | 4.2 | 4.0 | 4.3 | 4.0 | 8.0 |
| Piedmont Natural Gas | 1.20 | 30.37 | 4.1 | 4.0 | 5.2 | 2.5 | 4.8 | 4.1 | 8.2 |
| Southern Company | 1.96 | 45.53 | 4.5 | 5.7 | 5.6 | 5.0 | 5.0 | 5.3 | 9.9 |
| Vectren Corp. | 1.40 | 29.01 | 5.1 | 5.6 | 5.5 | 6.5 | 4.3 | 5.5 | 10.6 |
| WGL Holdings Inc. | 1.60 | 39.52 | 4.2 | 5.5 | 4.6 | 3.0 | 4.9 | 4.5 | 8.7 |
| Wisconsin Energy Corp. | 1.20 | 36.40 | 3.5 | 4.5 | 6.2 | 6.5 | 5.3 | 5.6 | 9.1 |
| Xcel Energy Inc. | 1.04 | 27.12 | 4.0 | 4.6 | 5.1 | 5.0 | 4.9 | 4.9 | 8.9 |
| **Mean** | **1.70** | **40.06** | 4.4 | 4.7 | **5.2** | **4.9** | 4.7 | 4.9 | **9.3** |
| **Median** | **1.69** | **38.88** | 4.3 | 4.5 | **5.3** | **5.0** | **4.8** | **5.0** | **9.3** |

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))

[2/] Expected Dividend Yield (Col (3)) + Average of All EPS Estimates (Col (8))

Source: Bloomberg, www.reuters.com, Value Line (May and June 2012), www.yahoo.com, and www.zacks.com.

**DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES**
**(SUSTAINABLE GROWTH)**

| Company | Annualized Last Paid Dividend (1) | Average Daily Close Prices 3/16-6/15/2012 (2) | Expected Dividend Yield 1/ (3) | Forecast Return on Common Equity (4) | Forecast Earnings Retention Rate (5) | BR Growth 2/ (2nd Qtr.2012) (6) | SV Growth 3/ (2nd Qtr.2012) (7) | Sustainable Growth 4/ (2nd Qtr.2012) (8) | DCF Cost of Equity 5/ (9) |
|---|---|---|---|---|---|---|---|---|---|
| AGL Resources Inc. | 1.84 | 38.25 | 5.1 | 11.6 | 51.2 | 5.9 | 0.28 | 6.2 | 11.3 |
| Alliant Energy Corp. | 1.80 | 43.87 | 4.3 | 11.0 | 37.1 | 4.1 | 0.25 | 4.3 | 8.6 |
| Atmos Energy Corp. | 1.38 | 32.25 | 4.4 | 7.9 | 45.2 | 3.6 | 0.03 | 3.6 | 8.0 |
| Consolidated Edison | 2.42 | 59.15 | 4.2 | 9.2 | 41.2 | 3.8 | 0.00 | 3.8 | 8.0 |
| Integrys Energy Group Inc. | 2.72 | 53.62 | 5.2 | 9.9 | 34.1 | 3.4 | 0.00 | 3.4 | 8.6 |
| Northwest Natural Gas | 1.78 | 45.63 | 4.2 | 12.0 | 42.9 | 5.1 | 1.47 | 6.6 | 10.8 |
| Piedmont Natural Gas | 1.20 | 30.37 | 4.1 | 12.8 | 27.0 | 3.5 | -0.71 | 2.8 | 6.8 |
| Southern Company | 1.96 | 45.53 | 4.5 | 12.6 | 30.8 | 3.9 | 0.70 | 4.6 | 9.1 |
| Vectren Corp. | 1.40 | 29.01 | 5.1 | 12.2 | 36.0 | 4.4 | 0.64 | 5.0 | 10.1 |
| WGL Holdings Inc. | 1.60 | 39.52 | 4.2 | 10.0 | 37.5 | 3.7 | 0.10 | 3.8 | 8.0 |
| Wisconsin Energy Corp. | 1.20 | 36.40 | 3.4 | 13.9 | 34.5 | 4.8 | -0.33 | 4.5 | 7.9 |
| Xcel Energy Inc. | 1.04 | 27.12 | 4.0 | 10.6 | 40.0 | 4.2 | 0.32 | 4.5 | 8.5 |
| **Mean** | **1.70** | **40.06** | **4.4** | **11.14** | **38.14** | **4.20** | **0.23** | **4.4** | **8.8** |
| **Median** | **1.69** | **38.88** | **4.3** | **11.33** | **37.32** | **3.99** | **0.17** | **4.4** | **8.6** |

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))

2/ BR Growth = Col (4) * (Col (5) / 100)

3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [ 1- B/M ].

4/ Col (6) + Col (7)

5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: *Value Line* (May and June 2012) and www.yahoo.com.

## DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES (THREE-STAGE MODEL)

| Company | Annualized Last Paid Dividend | Average Daily Close Prices 3/16-6/15/2012 | Growth Rates: Stage 1: Average of All EPS Forecasts | Growth Rates: Stage 2: Average of Stage 1 & 3 | Growth Rates: Stage 3: GDP Growth 1/ | DCF Cost of Equity 2/ |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| AGL Resources Inc. | 1.84 | 38.25 | 4.6 | 4.7 | 4.9 | 9.8 |
| Alliant Energy Corp. | 1.80 | 43.87 | 6.0 | 5.4 | 4.9 | 9.4 |
| Atmos Energy Corp. | 1.38 | 32.25 | 5.0 | 5.0 | 4.9 | 9.4 |
| Consolidated Edison | 2.42 | 59.15 | 3.6 | 4.2 | 4.9 | 8.7 |
| Integrys Energy Group Inc. | 2.72 | 53.62 | 5.8 | 5.3 | 4.9 | 10.5 |
| Northwest Natural Gas | 1.78 | 45.63 | 4.0 | 4.4 | 4.9 | 8.6 |
| Piedmont Natural Gas | 1.20 | 30.37 | 4.1 | 4.5 | 4.9 | 8.7 |
| Southern Company | 1.96 | 45.53 | 5.3 | 5.1 | 4.9 | 9.5 |
| Vectren Corp. | 1.40 | 29.01 | 5.5 | 5.2 | 4.9 | 10.1 |
| WGL Holdings Inc. | 1.60 | 39.52 | 4.5 | 4.7 | 4.9 | 8.9 |
| Wisconsin Energy Corp. | 1.20 | 36.40 | 5.6 | 5.3 | 4.9 | 8.4 |
| Xcel Energy Inc. | 1.04 | 27.12 | 4.9 | 4.9 | 4.9 | 8.8 |
| **Mean** | **1.70** | **40.06** | **4.9** | **4.9** | **4.9** | **9.2** |
| **Median** | **1.69** | **38.88** | **5.0** | **4.9** | **4.9** | **9.2** |

1/ Forecast nominal rate of GDP growth, 2013-23

2/ Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Bloomberg, Blue Chip *Economic Indicators* (March 2012), www.reuters.com, *Value Line* (May and June 2012), www.yahoo.com, and www.zacks.com.

# DCF COST OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
## (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

| Company | Annualized Last Paid Dividend (1) | Average Daily Close Prices 3/16-6/15/2012 (2) | Expected Dividend Yield [1/] (3) | Reuters Long-Term EPS Forecasts (4) | DCF Cost of Equity [2/] (5) |
|---|---|---|---|---|---|
| Canadian Utilities Limited | 1.77 | 67.48 | 2.8 | 6.2 | 8.9 |
| Emera Inc. | 1.35 | 33.82 | 4.3 | 6.5 | 10.7 |
| Enbridge Inc. | 1.13 | 39.53 | 3.2 | 10.4 | 13.6 |
| Fortis Inc. | 1.20 | 33.07 | 3.9 | 6.9 | 10.8 |
| TransCanada Corp. | 1.76 | 42.85 | 4.4 | 7.8 | 12.2 |
| **Mean** | **1.44** | **43.35** | **3.7** | **7.5** | **11.2** |
| **Median** | **1.35** | **39.53** | **3.9** | **6.9** | **10.8** |

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))

[2/] Expected Dividend Yield (Col (3)) + EPS Estimate (Col (4))

Source: www.reuters.com and www.yahoo.com.

## DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
## (THREE-STAGE MODEL)

| Company | Annualized Last Paid Dividend | Average Daily Close Prices 3/16-6/15/2012 | Growth Rates: Stage 1: Reuters Long-Term EPS Forecasts | Growth Rates: Stage 2: Average of Stage 1 & 3 | Growth Rates: Stage 3: GDP Growth [1/] | DCF Cost of Equity [2/] |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Canadian Utilities Limited | 1.77 | 67.48 | 6.2 | 5.2 | 4.3 | 7.2 |
| Emera Inc. | 1.35 | 33.82 | 6.5 | 5.4 | 4.3 | 9.0 |
| Enbridge Inc. | 1.13 | 39.53 | 10.4 | 7.4 | 4.3 | 8.6 |
| Fortis Inc. | 1.20 | 33.07 | 6.9 | 5.6 | 4.3 | 8.7 |
| TransCanada Corp. | 1.76 | 42.85 | 7.8 | 6.0 | 4.3 | 9.5 |
| **Mean** | **1.44** | **43.35** | **7.5** | **5.9** | **4.3** | **8.6** |
| **Median** | **1.35** | **39.53** | **6.9** | **5.6** | **4.3** | **8.7** |

[1/] Forecast nominal rate of GDP growth, 2013-22

[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Consensus Economics, *Consensus Forecasts* (April 2012), www.reuters.com, and www.yahoo.com.

## RISK MEASURES FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

| Company Name | Debt Ratings S&P (1) | Debt Ratings DBRS (2) | Average of Five Year Betas Ending: 2010-2011 (3) | Average of Five Year Betas Ending: 2004-2011 (4) | 2010 Common Stock Equity (Total Capital) (5) | Average Market to Book Ratio 1995-2011 (6) | Average Market to Book Ratio 2004-2011 (7) |
|---|---|---|---|---|---|---|---|
| ALGOMA CENTRAL CORP | | | 0.92 | 0.73 | 79.3% | 1.01 | 1.03 |
| ASTRAL MEDIA INC | | | 0.68 | 0.74 | 69.5% | 1.75 | 1.78 |
| CANADA BREAD CO LTD | | | 0.64 | 0.63 | 98.5% | 1.98 | 2.18 |
| CANADIAN NATIONAL RAILWAY CO | A- | A(low) | 0.64 | 0.73 | 65.0% | 2.22 | 2.71 |
| CANADIAN PACIFIC RAILWAY LTD | BBB- | BBB(low) | 0.88 | 0.76 | 52.8% | 1.66 | 1.81 |
| CANADIAN TIRE CORP | BBB+ | BBB(high) | 0.71 | 0.72 | 76.9% | 1.68 | 1.72 |
| EMPIRE CO LTD | | | 0.45 | 0.56 | 73.9% | 1.40 | 1.31 |
| LEON'S FURNITURE LTD | | | 0.80 | 0.69 | 100.0% | 2.45 | 2.52 |
| LOBLAW COMPANIES LTD | BBB | BBB | 0.58 | 0.54 | 58.7% | 3.07 | 2.16 |
| MAPLE LEAF FOODS INC | | | 0.46 | 0.50 | 59.1% | 2.09 | 1.60 |
| METRO INC | BBB | BBB | 0.45 | 0.57 | 70.7% | 2.43 | 2.17 |
| REITMANS (CANADA) | | | 0.77 | 0.74 | 97.9% | 1.82 | 2.62 |
| RITCHIE BROS AUCTIONEERS INC | | | 0.65 | 0.47 | 80.8% | 4.84 | 4.84 |
| SAPUTO INC | | | 0.51 | 0.55 | 79.5% | 3.65 | 3.26 |
| SHOPPERS DRUG MART CORP | BBB+ | A(low) | 0.62 | 0.65 | 77.1% | 3.32 | 3.28 |
| THOMSON-REUTERS CORP | A- | A(low) | 0.56 | 0.61 | 71.9% | 2.36 | 1.84 |
| TOROMONT INDUSTRIES LTD | | BBB(high) | 0.84 | 0.76 | 74.2% | 2.79 | 2.67 |
| TORSTAR CORP | | BBB | 0.91 | 0.67 | 63.7% | 1.99 | 1.46 |
| TRANSCONTINENTAL INC | BBB | BBB(high) | 0.96 | 0.82 | 58.2% | 1.52 | 1.37 |
| UNI-SELECT INC | | | 0.64 | 0.58 | 68.9% | 2.07 | 1.86 |
| WESTON (GEORGE) LTD | BBB | BBB | 0.28 | 0.36 | 52.2% | 2.69 | 2.17 |
| **Mean** | **BBB+/BBB** | **BBB(high)** | **0.66** | **0.63** | **72.8%** | **2.32** | **2.21** |
| **Median** | **BBB** | **BBB(high)/BBB** | **0.65** | **0.64** | **71.9%** | **2.09** | **2.16** |

Source: Standard and Poor's Research Insight and DBRS

## RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

| Company Name | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Average 1995-2011 | Average 2004-2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALGOMA CENTRAL CORP | 13.3 | 12.3 | 52.7 | 8.5 | 3.8 | 1.1 | 14.8 | 9.3 | 4.7 | 9.2 | 11.2 | 13.4 | 15.1 | 10.3 | 8.8 | 7.3 | 14.9 | 12.4 | 11.3 |
| ASTRAL MEDIA INC | 1.3 | -9.5 | 7.1 | 7.8 | 6.4 | 4.4 | 8.2 | 10.0 | 10.0 | 10.9 | 12.1 | 13.1 | 13.0 | 14.7 | -12.6 | 14.8 | 13.4 | 7.4 | 9.9 |
| CANADA BREAD CO LTD | 12.6 | 12.8 | 14.2 | 1.3 | 2.7 | 7.4 | 8.6 | 13.9 | 9.6 | 14.3 | 14.5 | 9.5 | 13.7 | 9.7 | 10.6 | 8.0 | 7.2 | 10.0 | 10.9 |
| CANADIAN NATIONAL RAILWAY CO | -43.7 | 6.1 | 13.9 | 2.8 | 12.6 | 14.4 | 12.5 | 8.9 | 11.2 | 18.8 | 18.8 | 21.9 | 21.6 | 18.3 | 17.0 | 18.7 | 22.4 | 11.5 | 19.7 |
| CANADIAN PACIFIC RAILWAY LTD | -13.0 | 13.5 | 18.0 | 10.3 | 7.3 | 20.2 | 6.6 | 15.2 | 11.3 | 10.8 | 13.0 | 17.2 | 18.3 | 10.8 | 9.6 | 11.3 | 12.0 | 11.3 | 12.9 |
| CANADIAN TIRE CORP | 10.2 | 10.4 | 11.4 | 13.0 | 11.2 | 10.6 | 11.5 | 11.9 | 12.8 | 13.6 | 13.9 | 13.4 | 14.2 | 11.2 | 9.2 | 11.7 | 11.0 | 11.8 | 12.3 |
| EMPIRE CO LTD | 3.9 | 11.9 | 17.9 | 21.7 | 13.3 | 69.1 | 16.4 | 11.4 | 11.6 | 11.4 | 16.2 | 10.3 | 14.0 | 10.5 | 10.7 | 11.9 | 9.2 | 16.0 | 11.8 |
| LEON'S FURNITURE LTD | 14.0 | 13.4 | 15.1 | 16.7 | 21.1 | 19.3 | 17.3 | 17.1 | 16.5 | 18.9 | 19.2 | 19.6 | 19.2 | 18.8 | 15.6 | 16.1 | 13.6 | 17.1 | 17.6 |
| LOBLAW COMPANIES LTD | 13.3 | 14.2 | 15.3 | 12.8 | 13.7 | 15.7 | 16.8 | 18.9 | 19.1 | 19.1 | 13.2 | -3.9 | 6.0 | 9.6 | 10.8 | 10.4 | 11.9 | 12.8 | 9.6 |
| MAPLE LEAF FOODS INC | -6.7 | 14.8 | 14.7 | -6.3 | 17.9 | 8.0 | 10.3 | 12.2 | 4.8 | 13.0 | 9.9 | 0.5 | 19.2 | -3.2 | 4.5 | 2.1 | 7.9 | 7.3 | 6.7 |
| METRO INC | 22.6 | 22.8 | 24.7 | 20.5 | 20.8 | 22.8 | 24.1 | 23.9 | 23.8 | 21.0 | 16.1 | 15.6 | 15.1 | 14.7 | 16.4 | 16.6 | 15.4 | 19.8 | 16.4 |
| REITMANS (CANADA) | 6.2 | 0.8 | 8.9 | 9.4 | 30.1 | 10.2 | 12.6 | 10.5 | 15.4 | 22.0 | 23.5 | 20.0 | 24.7 | 16.9 | 13.0 | 16.8 | 9.4 | 14.7 | 18.3 |
| RITCHIE BROS AUCTIONEERS INC | nc | 35.6 | 19.9 | 38.8 | 18.2 | 12.4 | 13.1 | 15.5 | 14.7 | 12.4 | 17.2 | 16.5 | 17.5 | 24.8 | 17.2 | 11.5 | 12.9 | 18.6 | 16.3 |
| SAPUTO INC | nc | 37.3 | 18.9 | 19.3 | 18.6 | 16.0 | 19.4 | 18.1 | 19.5 | 18.8 | 14.1 | 16.2 | 18.3 | 15.5 | 19.1 | 21.7 | 21.5 | 19.5 | 18.2 |
| SHOPPERS DRUG MART CORP | na | na | na | na | nc | 2.5 | 2.0 | 13.8 | 15.0 | 15.8 | 16.0 | 16.5 | 17.0 | 17.2 | 16.1 | 14.7 | 14.5 | 13.4 | 16.0 |
| THOMSON-REUTERS CORP | 22.4 | 14.2 | 12.9 | 34.7 | 8.0 | 17.9 | 10.2 | 7.3 | 8.8 | 10.3 | 9.3 | 11.0 | 31.1 | 9.1 | 4.0 | 4.6 | -7.9 | 12.2 | 8.9 |
| TOROMONT INDUSTRIES LTD | 27.1 | 24.3 | 47.5 | 22.5 | 16.6 | 15.4 | 16.4 | 12.7 | 16.9 | 17.8 | 17.6 | 19.0 | 20.0 | 19.6 | 14.8 | 9.6 | 30.5 | 20.5 | 18.6 |
| TORSTAR CORP | 6.7 | 11.3 | 38.4 | -0.7 | 12.8 | 5.4 | -14.6 | 21.3 | 17.8 | 14.6 | 14.5 | 9.2 | 11.3 | -22.7 | 5.3 | 8.7 | 30.6 | 10.0 | 8.9 |
| TRANSCONTINENTAL INC | 9.3 | 0.8 | 10.6 | 11.2 | 11.4 | 13.7 | 4.0 | 18.9 | 17.5 | 13.9 | 13.3 | 12.2 | 10.3 | 0.7 | -7.7 | 15.4 | 6.5 | 9.5 | 8.1 |
| UNI-SELECT INC | 21.4 | 19.9 | 20.7 | 20.6 | 18.7 | 15.2 | 16.1 | 16.7 | 19.2 | 15.5 | 16.3 | 15.4 | 13.7 | 13.6 | 10.3 | 12.0 | 13.0 | 16.4 | 13.7 |
| WESTON (GEORGE) LTD | 12.9 | 15.1 | 14.5 | 37.3 | 14.0 | 17.4 | 18.5 | 18.3 | 19.4 | 10.2 | 16.2 | 1.6 | 12.7 | 17.5 | 17.6 | 7.1 | 11.9 | 15.4 | 11.9 |
| **Average** | **7.4** | **14.1** | **19.9** | **15.1** | **14.0** | **15.2** | **11.7** | **14.6** | **14.3** | **14.9** | **15.1** | **12.8** | **16.5** | **11.3** | **10.0** | **12.0** | **13.4** | **13.7** | **13.2** |
| **Median** | **11.4** | **13.5** | **15.2** | **12.9** | **13.5** | **14.4** | **12.6** | **13.9** | **15.0** | **14.3** | **14.5** | **13.4** | **15.1** | **13.6** | **10.7** | **11.7** | **12.9** | **12.8** | **12.3** |
| **Average of Annual Medians** | | | | | | | | | | | | | | | | | | 13.4 | 13.5 |

Source: Standard and Poor's Research Insight.

## MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF CANADIAN UTILITIES

| | Debt and Preferred Shares at Par (Millions $, March 2012) (1) | Common Share Price Average Daily Close 3/16-6/15/2012 (2) | Common Shares Outstanding (Millions, March 2012) (3) | Total Market Capitalization (Millions $) (4) | Market Value Common Equity Ratio (5) |
|---|---|---|---|---|---|
| Canadian Utilities Limited | 5,395 | 67.48 | 128 | 8,613 | 61.5% |
| Emera Inc. | 3,700 | 33.82 | 123 | 4,176 | 53.0% |
| Enbridge Inc. | 22,107 | 39.53 | 785 | 31,031 | 58.4% |
| Fortis Inc. | 6,889 | 33.07 | 189 | 6,261 | 47.6% |
| TransCanada Corp. | 22,406 | 42.85 | 704 | 30,165 | 57.4% |
| **Mean** | | | | **$16,049** | **55.6%** |
| **Median** | | | | **$8,613** | **57.4%** |

## MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF U.S. UTILITIES

| | Debt and Preferred Shares at Par (Millions $, March 2012) (1) | Common Share Price Average Daily Close 3/16-6/15/2012 (2) | Common Shares Outstanding (Millions, March 2012) (3) | Total Market Capitalization (Millions $) (4) | Market Value Common Equity Ratio (5) |
|---|---|---|---|---|---|
| AGL Resources Inc. | 4,288 | 38.25 | 117 | 4,463 | 51.0% |
| Alliant Energy Corp. | 2,992 | 43.87 | 111 | 4,857 | 61.9% |
| Atmos Energy Corp. | 2,380 | 32.25 | 90 | 2,904 | 55.0% |
| Consolidated Edison | 11,071 | 59.15 | 293 | 17,326 | 61.0% |
| Integrys Energy Group Inc. | 2,479 | 53.62 | 78 | 4,178 | 62.8% |
| Northwest Natural Gas | 755 | 45.63 | 27 | 1,222 | 61.8% |
| Piedmont Natural Gas | 1,133 | 30.37 | 72 | 2,191 | 65.9% |
| Southern Company | 22,668 | 45.53 | 868 | 39,521 | 63.6% |
| Vectren Corp. | 1,796 | 29.01 | 82 | 2,376 | 57.0% |
| WGL Holdings Inc. | 771 | 39.52 | 52 | 2,035 | 72.5% |
| Wisconsin Energy Corp. | 5,224 | 36.40 | 231 | 8,390 | 61.6% |
| Xcel Energy Inc. | 10,247 | 27.12 | 487 | 13,218 | 56.3% |
| **Mean** | | | | **$8,557** | **60.9%** |
| **Median** | | | | **$4,321** | **61.7%** |

Source: Reports to Shareholders, www.yahoo.com

## QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES:

**Formula for After-Tax Weighted Average Cost of Capital:**

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

**APPROACH 1:**

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio)

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

**ASSUMPTIONS:**

| | | |
|---|---|---|
| Debt Cost | = | Market Cost of Long Term Debt for A rated utility |
| | = | 5.35% |
| Equity Cost | = | 9.60% |
| Tax Rate | = | 26.25% |
| CEQ Ratio | Step (1) | 57.0% |
| Debt Ratio | Step (1) | 43.0% |
| CEQ Ratio | Step (2) | 40.0% |
| Debt Ratio | Step (2) | 60.0% |

**STEPS:**

1. Estimate $WACC_{AT}$ for the less levered sa (common equity ratio of 57.0%)

   $WACC_{AT}$ = (5.35%)(1-.263)(43.0%) + (9.60%)(57.0%)
   = 7.17%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio $WACC_{AT}$ unchanged at 7.17%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.17% = (5.35%)(1-.263)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 12.00%

3. Difference between Equity Return at 57.0% and 40.0% common equity ratios:

   12.00% - 9.60% = 2.40% (240 basis points)

**APPROACH 2:**

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

**ASSUMPTIONS:**

| | | |
|---|---|---|
| Debt Cost | = | Market Cost of Long Term Debt for A rated utility |
| | = | 5.35% |
| Equity Cost | = | 9.60% |
| Tax Rate | = | 26.3% |
| CEQ Ratio | Step (1) | 57.0% |
| Debt Ratio | Step (1) | 43.0% |
| CEQ Ratio | Step (2) | 40.0% |
| Debt Ratio | Step (2) | 60.0% |

**STEPS:**

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 57.0%)

$WACC_{AT}$ = (5.35%)(1-.263)(43.0%) + (9.60%)(57.0%)
= 7.17%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1-t \times \text{Debt Ratio}_{ML})/(1-t \times \text{Debt Ratio}_{LL})$

$$WACC_{AT(ML)} = 7.17\% \times \frac{(1-.263 \times 60.0\%)}{(1-.263 \times 43.0\%)}$$

$WACC_{AT(ML)}$ = 6.81%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $\text{Ratio}_{ML}$) + (Equity Cost)(Equity $\text{Ratio}_{ML}$)
6.81% = (5.35%)(1-.263)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 11.10%

4. Difference between Equity Return at 57.0% and 40.0% common equity ratios:

11.10% - 9.60% = 1.50% (150 basis points)

# Appendix G

# WRITTEN EVIDENCE OF
# DR. JAMES H. VANDER WEIDE, PhD

**BRITISH COLUMBIA UTILITIES COMMISSION**

**GENERIC COST OF CAPITAL PROCEEDING**

**JAMES H. VANDER WEIDE, PH.D.**

**FOR**

**FORTISBC UTILITIES**

**AUGUST 3, 2012**

## TABLE OF CONTENTS

I. Introduction ........ 5

II. The Fair Rate of Return Standard ........ 6

III. Business and Financial Risks ........ 10

IV. Comparable Risk Utilities ........ 13

V. Estimates of Comparable Utilities' Cost of Equity ........ 25

A. Discounted Cash Flow Estimate ........ 25

B. Risk Premium Method ........ 31

1. Ex Post Risk Premium Method ........ 32

2. Ex Ante Risk Premium Estimate ........ 35

C. Capital Asset Pricing Model ("CAPM") ........ 38

D. Cost of Equity Conclusion ........ 44

VI. Allowed ROEs and Equity Ratios for Comparable Risk Utilities ........ 44

VII. The Formula Approach to Setting FEI's ROE ........ 47

VIII. Summary and Recommendations ........ 49

| | |
|---|---|
| Exhibit 1 | Segment Information BMO CM Canadian Utilities Companies |
| Exhibit 2 | Segment Information S&P/TSX Utilities Index Companies |
| Exhibit 3 | Percent of Total Assets for Regulated Utility Services Comprehensive U.S. Utility Group |
| Exhibit 4 | Percent of Total Assets for Regulated Utility Services Smaller Group of U.S. Utilities with Mostly Regulated Assets and S&P Bond Rating Equal to or Greater than BBB |
| Exhibit 5 | Standard & Poor's Bond Ratings for U.S. Utility Groups |
| Exhibit 6 | Summary of Discounted Cash Flow Analysis for Comprehensive Group of U.S. Utilities |
| Exhibit 7 | Summary of Discounted Cash Flow Analysis for Smaller Group of U.S. Utilities with Mostly Regulated Assets and S&P Bond Rating Equal to or Greater than BBB |
| Exhibit 8 | Experienced Risk Premiums on S&P/TSX Canadian Utilities Stock Index 1956—2011 |
| Exhibit 9 | Experienced Risk Premiums on BMO Capital Markets Utilities Stock Data Set 1983—2011 |
| Exhibit 10 | Comparison of DCF Expected Return on an Investment in Electric Utilities to the Interest Rate on Long-Term Government Bonds |
| Exhibit 11 | Comparison of DCF Expected Return on an Investment in Natural Gas Utilities to the Interest Rate on Long-Term Government Bonds |
| Exhibit 12 | Calculation of Capital Asset Pricing Model Cost of Equity Using SBBI 6.6 percent Risk Premium |
| Exhibit 13 | Comparison of Risk Premia on S&P500 and S&P Utilities 1937 – 2012 |

| | |
|---|---|
| Exhibit 14 | Calculation of Capital Asset Pricing Model Cost of Equity Using SBBI 6.6 percent Risk Premium and 0.92 Historical Utility Beta |
| Exhibit 15 | Comparison of Risk Premia on S&P TSX Composite, S&P TSX Utilities, and BMO Capital Markets Utility Group, 1956 – 2012 and 1983 - 2012 |
| Exhibit 16 | Allowed Returns on Equity for U.S. Electric Utilities 2010 – June 2012 |
| Exhibit 17 | Allowed Returns on Equity for U.S. Natural Gas Utilities 2010 – June 2012 |
| Exhibit 18 | Allowed Equity Ratios for U.S. Electric Utilities 2010 – June 2012 |
| Exhibit 19 | Allowed Equity Ratios for U.S. Natural Gas Utilities 2010 – June 2012 |
| Exhibit 20 | Market Value Equity Ratios for Comprehensive Group U.S. Utilities |
| Exhibit 21 | Market Value Equity Ratios for Smaller Group of U.S. Utilities with Mostly Regulated Assets and S&P Bond Rating Equal to or Greater than BBB |
| Exhibit 22 | Appendix 1 Qualifications of James H. Vander Weide |
| Exhibit 23 | Appendix 2 Estimating the Expected Return on Utility Stocks Using the DCF Model |
| Exhibit 24 | Appendix 3 The Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates |

# I. Introduction

Q 1 What is your name, occupation, and business address?

A 1 My name is James H. Vander Weide. I am Research Professor of Finance and Economics at Duke University, Fuqua School of Business. I am also President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to corporate clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q 2 Please summarize your qualifications.

A 2 I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke. A summary of my research, teaching, and other professional experience is presented in Appendix 1.

Q 3 Have you previously testified on financial and economic issues?

A 3 Yes. As an expert on financial and economic theory and practice, I have participated in more than four hundred regulatory and legal proceedings before the Canadian National Energy Board, the Federal Energy Regulatory Commission, the Canadian Radio-Television and Telecommunications Commission, the U.S. Federal Communications Commission, the U.S. Congress, the National Telecommunications and Information Administration, the public utility commissions of forty-three states and four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the U.S. Tax Court, the U.S. District Court for the District of Nebraska; the U.S. District Court for the District of New Hampshire; the U.S. District Court for the District of Northern Illinois; the U.S. District Court for the Eastern

District of North Carolina; the Montana Second Judicial District Court, Silver Bow County; the U.S. District Court for the Northern District of California; the Superior Court, North Carolina; the U.S. Bankruptcy Court for the Southern District of West Virginia; and the U. S. District Court for the Eastern District of Michigan.

Q 4 What is the purpose of your written evidence in this proceeding?

A 4 I have been asked by FortisBC Utilities to: (1) prepare an independent analysis of the cost of equity for the proposed benchmark utility, FortisBC Energy Inc. ("FEI" or "the Company"); (2) recommend an appropriate fair rate of return on equity ("ROE") and deemed equity ratio for FEI; and (3) assess the reasonableness of the returns provided by ROE adjustment formulas such as the formula previously used by the British Columbia Utilities Commission ("BCUC" or "the Commission").

## II. The Fair Rate of Return Standard

Q 5 Are you familiar with the fair rate of return standard?

A 5 Yes. The fair rate of return standard is a standard for determining whether a regulated company's allowed rate of return is just and reasonable. According to the fair rate of return standard, a regulated company's allowed return is considered to be just and reasonable, or fair, if it is: (1) equal to the returns investors expect to earn on other investments of comparable risk; (2) sufficient to allow the regulated company to attract capital on reasonable terms; and (3) sufficient to allow the regulated company to maintain its financial integrity.

Q 6 What is the economic definition of the required rate of return, or cost of capital, associated with particular investment decisions, such as the decision to invest in natural gas and electric utility facilities?

A 6 The economic definition of the cost of capital is similar to the definition of a fair return, namely, the cost of capital is the return investors expect to receive on alternative investments of comparable risk.

Q 7 Given the similarity of the definitions of "fair return" and "cost of capital," how do commissioners and economists generally determine whether a particular allowed return satisfies the fair return standard?

A 7 Commissioners and economists generally determine whether a particular allowed return satisfies the fair return standard by comparing the allowed return to one or more estimates of the regulated utility's cost of capital.

Q 8 How does the cost of capital affect a firm's investment decisions?

A 8 From an economic perspective, a firm should only invest in a specific project if the expected return on the investment is greater than or equal to the company's cost of capital. Thus, the cost of capital serves as a hurdle rate for the firm's investment decisions.

Q 9 How does the cost of capital affect investors' willingness to invest in a company?

A 9 The cost of capital measures the return investors can expect to earn on other investments of comparable risk. Because rational investors will not invest in a particular investment if the expected return on that investment is less than the cost of capital, the cost of capital is also a hurdle rate for investors' decision to invest in a company or project. If investors cannot earn a return that is at least equal to the return they expect to earn on other investments of comparable risk, they will not invest in the company or project.

Q 10 Do all investors have the same position in the firm?

A 10 No. Bond investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than bond investments. Thus, the cost of equity exceeds the cost of debt.

Q 11 What is the overall or average cost of capital?

A 11 The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q 12 Can you illustrate the calculation of the overall or weighted average cost of capital?

A 12 Yes. Assume that the cost of debt is 6 percent, the cost of equity is 11 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by .50 times 6 percent plus .50 times 11 percent, or 8.5 percent.[1]

Q 13 How do economists define the cost of equity?

A 13 Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, the cost of equity is greater than the cost of debt. The cost of equity, like the cost of debt, is both forward looking and market based.

Q 14 How do economists measure the percentages of debt and equity in a firm's capital structure?

A 14 Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. The percentage of debt is then calculated by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market values of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q 15 Why do economists measure a firm's capital structure in terms of the market values of its debt and equity?

A 15 Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is equal to the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected

[1] The weighted average cost of capital may be calculated on either an after-tax or a before-tax basis. The difference between these calculations is that the after-tax cost of debt is used to calculate the weighted average cost of capital in an after-tax calculation. For simplicity, I present a before-tax calculation of the weighted average cost of capital in this example.

return on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q 16 Why do investors measure the expected return on their investment portfolios using market value weights rather than book value weights?

A 16 Investors measure the expected return on their investment portfolios using market value weights because they calculate the expected return by dividing the expected future value of the investment by the current value of the investment, and market value is the best measure of the current value of the investment. From the point of view of investors, the historical cost or book value of their investment is entirely irrelevant to their calculation of their expected return on investment because they would receive market value, not historical cost, if they were to sell their investments. Thus, the expected return can only be measured in terms of market values.

Q 17 Do investors also use market value weights to measure the risk of their investments?

A 17 Yes. Investors measure risk by calculating the variance of their actual investment return from their expected investment return. Because investors measure both actual and expected investment returns using market value weights, they also measure risk using market value weights.

Q. 18 Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. 18 No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book values of debt and equity in a company's capital structure.

Q 19 Are these economic principles regarding the fair return on capital recognized in any Supreme Court cases?

A 19 Yes. These economic principles regarding the fair rate of return on capital are recognized in at least one Canadian and two United States Supreme Court cases: (1) *Northwestern Utilities Ltd. v. Edmonton*, (1929); (2) *Bluefield Water Works and Improvement Co. v. Public Service Commission*; and (3) *Federal Power Commission v. Hope Natural Gas Co*. In *Northwestern Utilities Ltd. v. Edmonton*, Mr. Justice Lamont states:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. [*Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186.]

The Court clearly recognizes here that a regulated utility must be allowed to earn a return on the value of its property that is at least equal to its cost of capital.

## III. Business and Financial Risks

Q. 20 The fair return standard requires that investors in public utilities be given an opportunity to earn a return that is commensurate with returns on other investments of similar risk. Are the returns on investment opportunities, such as an investment in FEI, known with certainty at the time an investment is made?

A. 20 No. The return on an investment in a company depends on the company's expected future cash flows over the life of the investment. Since the company's expected future cash flows are uncertain at the time the investment is made, the return on the investment is also uncertain.

Q. 21 Investors require a return on investment that is equal to the return they expect to receive on other investments of similar risk. Does the required return on an investment depend on the risk of that investment?

A. 21 Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q. 22 What fundamental risk do investors face when they invest in a company such as FEI?

A. 22 Investors face the fundamental risk that their realized, or actual, return on investment over the life of the investment (including the return of investment) will be less than their required return on investment.

Q. 23 How do investors attempt to measure investment risk?

A. 23 Investors generally attempt to measure investment risk by estimating the probability, or likelihood, of earning an actual return on the investment that is less than their required return on investment. For investments or projects with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Q. 24 Can investment risk be measured precisely?

A. 24 No. Because the risk of earning an actual return that is less than an investor’s required return depends on the investor’s estimate of the probability distribution of future cash flows in all future years, and the probability distribution of future cash flows is difficult to estimate, the risk of earning less than the required return cannot be measured precisely.

Q. 25 Do investors distinguish between business and financial risk?

A. 25 Yes. Business risk is the fundamental risk that investors will earn an operating return on their investment (that is, a return prior to financing costs) that is less than their required return on investment. Financial risk is the additional risk of earning less than the required return on equity when an investment is partially financed with fixed-cost debt.

Q. 26 Does the use of fixed-cost debt generally increase the expected return on the equity-financed portion of an investment?

A. 26 Yes. The use of fixed-cost debt increases both the expected and the realized return on equity when the operating return on investment exceeds the cost of debt. The use of fixed-cost debt financing is generally called “financial leverage.”

Q. 27 You note that financial leverage increases the risk of investors in natural gas utilities. How do economists measure financial leverage?

A. 27 Economists generally measure financial leverage by the percentages of debt and equity in a company's market value capital structure. Companies with a high percentage of debt compared to equity are considered to have high financial leverage.

Q. 28 Why does high financial leverage affect the risk of investing in a natural gas utility's stock?

A. 28 High financial leverage is a source of additional risk to utility stock investors because it increases the percentage of the firm's costs that are fixed, and the presence of higher fixed costs increases the variability of the equity investors' return on investment.

Q 29 You note above that investors require a higher rate of return on more risky investments than less risky investments. Because financial risk is a key component of total risk, does a company with greater financial risk generally have a higher required rate of return on equity?

A 29 Yes. Holding business risk constant, a company with higher financial risk would have a higher required rate of return on equity.

Q 30 You also note above that financial risk reflects the impact of having a higher percentage of debt in a company's capital structure. Does the relationship between the cost of equity and the percentage of debt in the capital structure also require that the allowed return on equity and the percentage of equity in the capital structure be considered together?

A 30 Yes.

Q 31 Does the fair rate of return standard require that comparable risk investments be comparable with respect to both business and financial risk?

A 31 No. The fair rate of return standard only requires that comparable risk investments have comparable total risk. Thus, an investment with greater business risk can be risk comparable to an investment with lower business risk as long as the first investment's greater business risk is offset by its lower financial risk.

## IV. Comparable Risk Utilities

Q 32 Recognizing that risk cannot be measured precisely, how do you analyze FEI's cost of equity?

A 32 I analyze FEI's cost of equity by: (1) identifying several groups of utilities whose business risk is broadly comparable to FEI's business risk; (2) estimating the cost of equity for each group of comparable business risk utilities using cost of equity methodologies such as the discounted cash flow ("DCF"), risk premium and CAPM; and (3) adjusting the cost of equity results for my comparable groups to reflect the difference between the financial risk of the comparable group and the financial risk of FEI.

Q 33 Why do you apply your cost of equity methods to one or more groups of comparable business risk utilities, rather than solely to FEI?

A 33 I apply my cost of equity methods to one or more groups of comparable business risk utilities because standard cost of equity methods, such as the DCF, risk premium, and CAPM, require inputs of quantities that are not easily measured. Since these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each utility. However, the uncertainty in the estimate of the cost of equity for a single utility can be greatly reduced by applying cost of equity methods to samples of comparable business risk utilities. Intuitively, unusually high estimates for some utilities are offset by unusually low estimates for other utilities. Thus, financial economists invariably apply cost of equity methods to one or more groups of comparable business risk utilities. In utility regulation, the practice of using a group of comparable business risk utilities, called the comparable company approach, is further supported by the Supreme Court of Canada standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk.[2]

---

[2] See *Northwestern Utilities Ltd. v. Edmonton* [1929] S.C.R. 186.]

Q 34 Why do you apply your cost of equity methods to several groups of comparable business risk utilities, rather than to a single group of comparable business risk utilities?

A 34 I apply my cost of equity methods to several groups of comparable business risk utilities because, as discussed above, risk cannot be measured precisely. Recognizing that business risk cannot be measured precisely, the use of several groups of comparable business risk utilities provides insight on the impact of alternative definitions of business risk comparability on cost of equity results.

Q 35 What criteria do you use to select your groups of comparable business risk companies?

A 35 I use the criteria that similar business risk companies must be broadly similar in business risk and must constitute a relatively large sample of companies. Specifically, I require that comparable business risk companies: (1) must have stock that is publicly traded; (2) must have sufficient available data to reasonably apply standard cost of equity estimation techniques; (3) must have regulated natural gas and/or electric utility operations; and (4) taken together, must constitute a relatively large sample of companies. In this proceeding, I also refine the criterion that comparable business risk companies must have regulated natural gas and/or electric utility operations to specify that a company must have at least 80 percent of total assets devoted to regulated utility service and must have a bond rating of BBB or above.

Q 36 Is FEI included in your comparable company group?

A 36 No. FEI is not included in my comparable company group because its stock is not publicly traded.

Q 37 Why must comparable companies be publicly traded?

A 37 Comparable companies must be publicly traded because information on a company's stock price is a key input in standard cost of equity estimation methods. If the company is not publicly traded, the information required to estimate the cost of equity will not be available.

Q 38 Why is data availability a concern in estimating the cost of equity for FEI?

A 38 Data availability is a concern because standard cost of equity estimation methods like the DCF, risk premium, and CAPM require estimates of inputs, such as the expected growth rate, required risk premium, and the beta, that are inherently uncertain. If there are insufficient data available to estimate these inputs, there is little basis for arriving at a reasonable estimate of the cost of equity for the comparable risk companies.

Q 39 Why do you include both natural gas and electric utilities in your comparable risk groups, rather than relying solely on a proxy group of natural gas utilities?

A 39 I include both natural gas and electric utilities in my comparable risk groups to ensure that there is a sufficiently large group of companies to reliably estimate the cost of equity. In this regard, I note that: (1) there are no Canadian natural gas utilities with publicly-traded stock; (2) there are relatively few publicly-traded North American natural gas utilities with sufficient data to estimate the cost of equity; and (3) regulated natural gas and electric utilities generally face similar risks.

Q 40 Recognizing the inherent difficulties in selecting comparable risk companies, what companies do you consider as potential risk-comparable companies for the purpose of estimating FEI's cost of equity?

A 40 I consider two groups of Canadian utilities and two groups of U.S. utilities.

Q 41 What two groups of Canadian utilities do you consider?

A 41 I consider the small group of Canadian utilities included in the BMO CM basket of utility and pipeline companies and a larger group consisting of the companies in the S&P/TSX utilities index.

Q 42 What companies are included in the BMO CM basket of Canadian utility stocks?

A 42 The BMO CM basket of Canadian utility stocks includes Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. The BMO CM basket also includes return data for Westcoast Energy Inc. until December 2001 and Terasen Inc. through July 2005.

Q 43 Does the BMO CM basket of Canadian utilities include all large publicly-traded Canadian operating utilities with a significant percentage of assets devoted to regulated utility services?

A 43 Yes. The five companies in the BMO CM basket of Canadian utilities are the only large publicly-traded Canadian operating utilities with a significant percentage of assets devoted to regulated utility services.

Q 44 Can you provide a general overview of the business operations of the companies in the BMO CM basket of Canadian utilities?

A 44 Yes. The business operations of the companies in the BMO CM basket of Canadian utilities may be summarized as follows.

Canadian Utilities Ltd. An international energy company with business operations in Canada, Great Britain, and Australia. Major business segments include Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage, and liquids extraction); Structure & Logistics (manufacturing, logistics, and noise abatement); and Technologies (business systems solutions). Canadian Utilities has approximately 68 percent of total assets devoted to its utilities segment.

Emera Inc. Invests in electricity generation, transmission, and distribution, gas transmission, and utility energy services. Its business segments include NSPI, Maine Utility Operations, Caribbean Utility Operations, and Brunswick Pipelines. Emera has approximately 56 percent of total assets associated with its electric utility operations in Nova Scotia and an additional 26 percent associated with its electric utility operations in Maine and the Caribbean.

Enbridge Inc. A leader in energy transportation and distribution in North America and internationally. Enbridge has approximately 38 percent of its total assets associated with its Liquids Pipelines segment and 25 percent of total assets associated with its Gas Distribution segment.

Fortis Inc. Invests in regulated electric and gas utility operations, non-regulated electric generation operations, and real estate operations. Fortis Inc. has approximately 85 percent of its total assets associated with its Canadian utility operations. Fortis Inc. is the ultimate parent of FEI.

TransCanada Corp. Operates the most extensive natural gas pipeline in Canada, owns and operates large natural gas and oil pipeline systems in North America, and invests in unregulated power projects. TransCanada has approximately 48 percent of its total assets associated with its natural gas pipeline operations, 19 percent with its oil pipeline operations, and 29 percent with its power generation and energy infrastructure operations.

Specific segment information for each of these companies is shown in Exhibit 1.

Q 45 What are the advantages of using the BMO CM basket of Canadian utilities as risk comparables for the purpose of estimating the cost of equity for FEI?

A 45 The primary advantage of the BMO CM basket of Canadian utilities is that it only includes Canadian companies that receive a significant portion of their revenues from regulated utility operations.

Q 46 What are the disadvantages of using the BMO CM basket of Canadian utilities as risk comparables for the purpose of estimating the cost of equity for FEI?

A 46 The primary disadvantage of the BMO CM basket of Canadian utilities is that at least two of the five companies also have significant investments in unregulated operations; and some of their investments in regulated operations are pipeline operations rather than electric or natural gas utility operations.

Q 47 What companies are included in the S&P/TSX utilities index?

A 47 The companies currently included in the S&P/TSX utilities stock index are ATCO Ltd., Atlantic Power Corporation, Algonquin Power & Utilities Corp., Capital Power Corporation, Canadian Utilities Limited, Emera Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power Inc., and TransAlta Corporation.

Q 48 Are any of the companies in the S&P/TSX utilities index related to one another?

A 48 Yes. ATCO Ltd. is a utility holding company that owns 52 percent of Canadian Utilities Limited. Since ATCO has a majority interest in Canadian Utilities and only a small amount of assets that are not jointly owned with Canadian Utilities, ATCO's financial statements reflect essentially the same information as Canadian Utilities' financial statements.

Q 49 The S&P/TSX utilities index contains six other companies that are not included in the BMO CM basket of Canadian utilities. Can you provide a general overview of the companies in the S&P/TSX utilities index that are not included either directly or indirectly in the BMO CM basket of Canadian utilities?

A 49 Yes. The business operations of these six companies can be summarized as follows.

Atlantic Power Corporation. An independent electric power producer that owns interests in a diversified portfolio of independent non-utility power generation projects and one transmission line in the United States.

Algonquin Power & Utilities Corp. Owns and operates a diversified portfolio of renewable energy and utility businesses through its subsidiary companies. Algonquin has two business segments: Algonquin Power Company generates and sells electric energy; and Liberty Utilities provides utility services related to electricity, natural gas, water, and wastewater. Algonquin has approximately 51 percent of its total assets that are related to its unregulated electric power generation and marketing segment and 34 percent related to its utilities segment.

Capital Power Corporation. An independent North American power producer that develops, acquires, and operates power generation from a variety of energy sources.

Just Energy Group Inc. Primarily involved in the sale of natural gas, electricity, and green energy products to residential and commercial customers under long-term contracts in the United States and Canada.

Northland Power Inc. Operates power generating stations and wind farms, sells electricity and steam, and implements environmental and monitoring systems.

TransAlta Corporation. A wholesale power generator and marketer with operations in Canada, the United States, and Australia.

Exhibit 2 shows segment information for the two companies in the S&P/TSX Utilities index with regulated utility operations that are not in the BMO CM data set. The remaining six companies' total assets are only associated with unregulated business operations.

Q 50 What are the advantages of using the S&P/TSX utilities index as comparables in this proceeding?

A 50 The primary advantage of using the S&P/TSX utilities index is that there are more companies in the index and return data for this index is available for a longer period of time than for the BMO CM basket of utility stocks.

Q 51 Are there any disadvantages of using the S&P/TSX Utilities as risk comparables for FEI?

A 51 Yes. The primary disadvantage is that six of the ten companies in this group do not have a significant percentage of assets devoted to regulated utility service, and the financial statements of two of the companies with a significant percentage of regulated assets reflect essentially the same information.

Q 52 What two groups of U.S. utilities do you consider?

A 52 I consider a large utility company group that includes all publicly-traded natural gas and electric utilities with sufficient data to reasonably estimate FEI's cost of equity and a smaller group of natural gas and electric utilities that includes only utilities that have at least 80 percent of total assets devoted to regulated utility operations and S&P bond ratings equal to or greater than BBB.

Q 53 What are the advantages of using U.S. utility groups to estimate the cost of equity for FEI?

A 53 The primary advantages of using U.S. utility groups to estimate FEI's cost of equity are that: (1) they include a significantly larger sample of companies with traditional utility operations than my Canadian groups; (2) reasonable estimates of expected growth rates are available for these companies, whereas the same data are not available for the Canadian utilities; and (3) historical data for the U.S. utilities are available for a much longer period of time than for the Canadian utilities.

Q 54 Is there a significant difference in the business risk of Canadian and U.S. utilities?

A 54 No. Generally speaking, the business risk of natural gas and electric utilities is approximately the same in the U.S. as it is in Canada.

Q 55 Why is the business risk of natural gas and electric utilities approximately the same in the U.S. as it is in Canada?

A 55 The business risk of natural gas and electric utilities is approximately the same in the U.S. and Canada because: (1) U.S. natural gas and electric utilities rely on essentially the same natural gas and electric technologies to deliver their services to the public as natural gas and electric utilities in Canada; (2) the economics of natural gas and electric transmission and distribution is similar in the U.S. and Canada; and (3) U.S. natural gas and electric utilities are regulated under similar cost-based regulatory structures and fair rate of return principles as Canadian utilities.

Q 56 Some observers have argued that Canadian utilities have lower regulatory risk than U.S. utilities because Canadian regulators generally make greater use of cost adjustment and revenue stabilization mechanisms than U.S. regulators. Do you agree with this argument?

A 56 No. U.S. utilities have many of the same cost adjustment and revenue stabilization mechanisms as Canadian utilities. For example, U.S. natural gas distribution companies typically have cost adjustment mechanisms for the cost of purchased gas, removal expenses, and bad debt expenses; and revenue stabilization mechanisms for weather normalization and declining customer usage. In addition, U.S. natural gas utilities increasingly have rate designs that allow them to recover higher percentages of their fixed costs through fixed monthly rates rather than through variable rates. U.S. electric utilities generally have cost adjustment mechanisms for costs of fuel and purchased power, pension expenses, storm damage expenses, environmental expenses, decommissioning expenses, demand-side management program costs, FERC-approved transmission costs, and new generation plant investment; and revenue stabilization mechanisms for unusual weather and customer usage.

Q 57 Are there other factors that reduce the risk of investing in U.S. utilities?

A 57 Yes. U.S. utilities' regulatory risk may be reduced because U.S. utilities frequently operate in several regulatory jurisdictions. In addition, U.S. utilities' risk may be reduced because U.S. utilities are generally allowed to normalize the benefits of deferred taxes, whereas Canadian utilities are generally required to flow such benefits through to rate payers.

Q 58 Do cost recovery and revenue stabilization mechanisms guarantee that a public utility will earn its cost of equity?

A 58 No. Regulatory risk is associated with the possibility that a utility will be unable to earn its required rate of return as a result of regulation. Although cost recovery and revenue stabilization mechanisms generally reduce the gap between a utility's actual and allowed returns, they do not necessarily reduce the gap between a utility's actual and required returns. If a utility's allowed ROE is less than its required ROE, the utility may have high regulatory risk, even if it is able to earn its allowed ROE.

Q 59 You note above that financial risk is the additional variability in return on investment that equity investors experience due to the company's use of debt financing or leverage. How does the financial risk of Canadian utilities compare to the financial risk of U.S. utilities?

A 59 Canadian utilities generally have greater financial risk than U.S. utilities because, as shown below, they rely more heavily on debt financing than U.S. utilities.

Q 60 What percent of total assets in your U.S. utility groups are devoted to regulated utility services?

A 60 On average, the companies in my larger U.S. utility sample have 83 percent of total assets associated with regulated utility operations (see Exhibit 3). Approximately 93 percent of total assets of my smaller U.S. utility group are devoted to regulated utility services (see Exhibit 4).

Q 61 What are the average bond ratings for the companies in your U.S. utility groups?

A 61 The average bond rating for the companies in my comprehensive U.S. utility group is BBB+, and the average bond rating for the companies in my smaller U.S. sample is A- (see Exhibit 5).

Q 62 What do bond ratings measure?

A 62 Bond ratings measure the risk that a company will be unable to pay the interest and principal on its debt. Hence, bond ratings are frequently considered to be a measure of the likelihood of a company declaring bankruptcy.

Q 63 Are bond ratings a reasonable measure of the risk of investing in a company's stock?

A 63 No. As discussed above, the risk of investing in a company's stock is best measured by the expected variability in the return on the stock investment.

Q 64 Do you have evidence that bond ratings are a poor indicator of the risk of investing in a company's equity?

A 64 Yes. I have examined the average allowed rate of return on equity for U.S. utilities in different bond rating categories, based on decisions beginning January 2010 through February 2012, to determine whether the allowed ROE depends on the utility's bond rating. If bond ratings are an indicator of the risk of investing in a utility's equity, one would expect that there would be an inverse relationship between a utility's bond rating and its allowed ROE, that is, that utilities with higher bond ratings would have lower allowed ROEs and vice versa. However, I find no significant difference in allowed ROEs for utilities in different bond rating categories (see Table 1 below).

**TABLE 1**
**COMPARISON OF ALLOWED RATES OF RETURN**
**TO BOND RATING CATEGORY**

| BOND RATING CATEGORY | NUMBER OF COMPANIES IN CATEGORY | RETURN ON EQUITY | EQUITY RATIO |
|---|---|---|---|
| A- and above | 55 | 10.3 | 50.7 |
| BBB+ | 39 | 10.2 | 48.6 |
| BBB | 39 | 10.3 | 47.9 |
| BBB- | 28 | 10.1 | 48.5 |
| Below investment grade | 11 | 10.0 | 47.5 |
| Total/Average | 172 | 10.2 | 49.1 |

Q 65 Based on the evidence you have reviewed, should the Commission give weight to cost of equity results for U.S. utilities?

A 65 Yes. As discussed above, the U.S. utilities included in my cost of equity studies are generally comparable in business risk to the Canadian utilities. Furthermore, the U.S. utilities included in my studies are more involved in traditional utility operations than most of the companies included in the Canadian utilities indices. In addition, the sample of U.S. regulated utilities is significantly larger than the sample of Canadian regulated utilities, and the data required to estimate the cost of equity are more readily available for the U.S. utilities than for the Canadian utilities. For these reasons, the U.S. data provide important information on the cost of equity for FEI and should be considered along with Canadian-specific evidence to estimate the cost of equity for FEI.

Q 66 Has the BCUC expressed an opinion on the use of U.S. utility data for the purpose of estimating the cost of equity for Terasen Gas (now FEI)?

A 66 Yes. In the Commission's Terasen Gas Decision on Return on Equity and Capital Structure, December 16, 2009, the Commission states:

> As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so. In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics. [In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure Decision, December 16, 2009, pp. 15 – 16]

Q 67 Has the Ontario Energy Board also determined that cost of equity evidence for U.S. utilities is useful in estimating the cost of equity for Ontario utilities?

A 67 Yes. In the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009, ("2009 Cost of Capital Report") the Board states:

> Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. …
>
> The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking. [2009 Cost of Capital Report at 21 – 23]

Q 68 Has the National Energy Board ("NEB") determined that cost of equity evidence for U.S. utilities is useful in determining the cost of equity for Trans Québec & Maritimes Pipeline Inc. ("TQM")?

A 68 Yes. In Decision RH-1-2008 the Board finds:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008. [RH-1-2008 at 71.]

Q 69 What conclusions do you draw from your investigation of alternative groups of comparable utilities?

A 69 I conclude that my groups of Canadian and U.S. utilities are reasonable proxies for the purpose of estimating FEI's cost of equity.

## V. Estimates of Comparable Utilities' Cost of Equity

Q 70 What methods do you use to estimate your comparable utilities' cost of equity?

A 70 I use three generally accepted methods: the discounted cash flow ("DCF"), the risk premium, and the CAPM. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The risk premium method assumes that the investor's required rate of return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The CAPM assumes that the investors' required rate of return is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

### A. Discounted Cash Flow Estimate

Q 71 Please describe the DCF model.

A 71 The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

**EQUATION 1**

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

| | | |
|---|---|---|
| $P_B$ | = | Bond price; |
| C | = | Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually); |
| F | = | Face value of the bond; |
| i | = | The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and |
| n | = | The number of periods before the bond matures. |

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

**EQUATION 2**

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

| | | |
|---|---|---|
| $P_S$ | = | Current price of the firm's stock; |
| $D_1, D_2 \ldots D_n$ | = | Expected annual dividend per share on the firm's stock; |
| $P_n$ | = | Price per share of stock at the time the investor expects to sell the stock; and |

k = Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where *k* is the cost of equity, $D_1$ is the expected next period annual dividend, $P_s$ is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term $D_1/P_s$ is called the dividend yield component of the annual DCF model, and the term *g* is called the growth component of the annual DCF model.

Q 72 Are you recommending that the annual DCF model be used to estimate FEI's cost of equity?

A 72 No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression for the present discounted value of future dividends if dividends are paid annually at the end of each year. Because the companies in my proxy group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these firms. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present discounted value of a quarterly stream of dividend payments.

Q 73 How do you estimate the dividend component of the DCF model?

A 73 The quarterly DCF model requires an estimate of the dividends, $d_1$, $d_2$, $d_3$, and $d_4$, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by the factor, (1 + the growth rate, g).

Q 74 How do you estimate the growth component of the quarterly DCF model?

A 74 I use the analysts' estimates of future earnings per share ("EPS") growth reported by I/B/E/S Thomson Reuters.

Q 75 What is I/B/E/S?

A 75 I/B/E/S is a firm (now owned by Thomson Reuters) that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance.

Q 76 Why do you use the I/B/E/S growth estimates?

A 76 The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of multiple reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q 77 Why do you rely on analysts' projections of future EPS growth to estimate the growth component of the DCF model rather than looking at past historical growth rates?

A 77 I rely on analysts' projections of future EPS growth because: (1) the DCF model assumes that a company's stock price is equal to the present value of all expected *future* cash flows from investing in the stock; (2) stock prices are determined by investors in the marketplace; and (3) I have found that analysts' growth forecasts are the best proxy for investor growth expectations.

Q 78 Does the DCF model require that analysts' growth forecasts be perfectly accurate?

A 78 No. The DCF model recognizes that all growth forecasts necessarily involve uncertainty. The DCF model only requires that the growth forecasts used in the model are reasonable proxies for investors' growth expectations.

Q 79 What price do you use in your DCF model?

A 79 I use a simple average of the monthly high and low stock prices for each firm for the three-month period ending May 2012. These high and low stock prices were obtained from I/B/E/S Thomson Reuters.

Q 80 Why do you use a three-month average stock price in applying the DCF method?

A 80 I use a three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

Q 81 How do you use the DCF model to estimate the cost of equity on an investment in your comparable risk companies?

A 81 As discussed above, I apply the DCF model to two groups of U.S. utilities.

Q 82 How do you select your larger comparable group of U.S. utilities?

A 82 I select the publicly-traded natural gas and electric utilities that: (1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least two analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3;[3] and (5) have an investment grade S&P bond rating.

Q 83 How do you select your smaller group of U.S. utilities?

A 83 Beginning with the larger group that has been selected, I select only those companies from the larger group that have at least 80 percent of total assets devoted to regulated utility operations and that have an S&P bond rating of BBB or higher.

Q 84 Why do you use U.S. utilities rather than Canadian utilities in your DCF studies?

A 84 As noted above, the DCF model requires estimates of investors' growth expectations, which are best measured from the average of analysts' growth forecasts for each company. The difficulty with using Canadian utilities is that there are very few, if any, analysts' growth forecasts available for the Canadian utilities. In addition, the number of publicly-

---

[3] The Value Line Investment Survey is a widely used independent investment information service that provides comprehensive reference information on approximately 1,700 publicly-traded stocks.

traded Canadian utilities is significantly less than the number of publicly-traded U.S. utilities.

Q 85 Why do you eliminate companies that have either decreased or eliminated their dividend during the past two years?

A 85 The DCF model requires the assumption that dividends will grow at a constant positive rate into the indefinite future. If a company has decreased its dividend in recent years, an assumption that the company's dividend will grow at a positive rate into the indefinite future is questionable.

Q 86 Why do you eliminate companies that have fewer than two analysts' estimates included in the I/B/E/S mean forecast?

A 86 The DCF model also requires a reliable estimate of a company's expected future growth. For most companies, the I/B/E/S mean growth forecast is the best available estimate of the growth term in the DCF Model. However, the I/B/E/S estimate may be less reliable if the mean estimate is based on the inputs of very few analysts. On the basis of my professional judgment, I believe that at least two analysts' estimates are a reasonable minimum number.

Q 87 Why do you eliminate companies that are being acquired in transactions that are not yet completed?

A 87 A merger announcement generally increases the target company's stock price. Analysts' growth forecasts for the target company, on the other hand, are necessarily related to the company as it currently exists. The use of a stock price that includes the growth-enhancing prospects of potential mergers in conjunction with growth forecasts that do not include the growth-enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q 88 For your smaller utility group, why do you retain only companies that have equal to or greater than 80 percent of total assets devoted to regulated utility operations and bond ratings equal to or greater than BBB?

A 88 For my smaller utility group, I retain only those companies in order to assess the impact of selection criteria relating to regulated assets and bond ratings on my estimate of the cost of equity.

Q 89 Please summarize the results of your application of the DCF model to your comparable groups of utilities.

A 89 My application of the DCF model to my comprehensive group of utilities produces a result of 10.3 percent, and to my smaller group of utilities, 10.0 percent (see Exhibit 6 and Exhibit 7).

### B. Risk Premium Method

Q 90 Please describe the risk premium method of estimating FEI's cost of equity.

A 90 The risk premium method is based on the principle that investors expect to earn a return on an equity investment in FEI that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q 91 Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A 91 No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks and the returns on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q 92 How do you measure the required risk premium on an equity investment in FEI?

A 92 I use two methods to estimate the required risk premium on an equity investment in FEI. The first is called the ex post risk premium method and the second is called the ex ante risk premium method.

### 1. Ex Post Risk Premium Method

Q 93 Please describe your ex post risk premium method for estimating the required risk premium on an equity investment in your comparable utilities.

A 93 My ex post risk premium method estimates the required risk premium on an equity investment in my comparable utilities from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds.

Q 94 How do you measure the returns experienced by investors in Canadian utility stocks?

A 94 I measure the returns experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index[4]; and (2) a basket of Canadian utility stocks created by the BMO CM.

Q 95 What companies are currently included in these indices of Canadian utility stock performance?

A 95 As discussed above, the companies included in the S&P/TSX utilities stock index are ATCO Ltd., Atlantic Power Corporation, Algonquin Power & Utilities Corp., Capital Power Corporation, Canadian Utilities Limited, Emera Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power Inc., and TransAlta Corporation.

The BMO CM basket of utility and pipeline companies includes Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. The BMO CM basket also includes return data for Westcoast Energy Inc. until December 2001 and Terasen Inc. through July 2005.

---

[4] The legacy S&P/TSX utilities index was discontinued by Standard & Poor's in Spring 2002 when Standard & Poor's introduced a new S&P/TSX Composite utilities index that included the GICs 5500 utilities. Standard & Poor's provided total return index value data going back to 1999. The historical data on returns earned by investors in the S&P/TSX utilities index therefore includes total returns on the S&P/TSX legacy utilities index through 1998 and total returns on the new S&P/TSX composite utilities index from 1999 through 2011.

Q 96 What time periods are covered in your Canadian utility stock return data?

A 96 The S&P/TSX utilities stock return data cover the period 1956 through 2011, and the BMO CM stock return data cover the period 1983 through 2011.

Q 97 Why do you analyze investors' experienced returns over such long time periods?

A 97 I analyze investors' experienced returns over long time periods because experienced returns over short periods can deviate significantly from expectations. However, I also recognize that experienced returns over long periods may also deviate from expected returns if the data in some portion of the long time period are unreliable.

Q 98 Would your study provide different risk premium results if you had included different time periods?

A 98 Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to go back as many years as it is possible to obtain reliable data. With regard to the S&P/TSX utilities index, the data begin in 1956, and for the BMO CM utility stock data set, the data begin in 1983.

Q 99 Why do you choose two sets of Canadian utilities stock return performance data rather than simply relying entirely on either the S&P/TSX utilities stock index data or the BMO CM utility stock data set?

A 99 I choose two sets of Canadian utility stock return performance data because each data set provides different information on Canadian utility stock returns. The S&P/TSX utilities index is valuable because it provides information on the returns experienced by investors in a portfolio of Canadian utility stocks over a relatively long period of time. However, six of the ten companies included in the S&P/TSX utility index operate mainly in non-traditional utility markets. The BMO CM utility stock return database is valuable because it provides information on the experienced returns for a sample of Canadian companies that receive a significantly higher percentage of revenues from traditional utility operations than the companies in the S&P/TSX index. However, the time period covered is not as long as the period covered by the S&P/TSX utility index.

Q 100 How are the experienced returns on an investment in each utility data set calculated?

A 100 The experienced returns on an investment in each utility data set are calculated from the historical record of stock prices and dividends for the companies in the data set. From the historical record of stock prices and dividends, the index sponsors construct an index of investors' wealth at the end of each period, assuming a $100 investment in the index at the time the index was constructed. An annual rate of return is calculated from the wealth index by dividing the wealth index at the end of each period by the wealth index at the beginning of the period and subtracting one [$r_t = (W_t \div W_{t-1}) - 1$].

Q 101 How do you measure the interest rate earned on long-term Canada bonds in your experienced, or ex post, risk premium studies?

A 101 I use the interest rate data on long-term Canada bonds reported by the Bank of Canada.

Q 102 What average risk premium results do you obtain from your analysis of returns experienced by investors in Canadian utility stocks?

A 102 The average experienced risk premium is 6.7 percent, as shown below in Table 2. (The annual data that produce these results are shown in Exhibit 8 and Exhibit 9.)

**TABLE 2**
**EX POST RISK PREMIUM RESULTS**

| COMPARABLE GROUP | PERIOD OF STUDY | AVERAGE STOCK RETURN | AVERAGE BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| S&P/TSX Utilities | 1956 – 2011 | 11.99 | 7.33 | 4.7 |
| BMO CM Utilities Stock Data Set | 1983 – 2011 | 16.01 | 7.24 | 8.8 |
| Average | | | | 6.7 |

Q 103 What conclusions do you draw from your experienced, or ex post, risk premium studies about the required risk premium on an investment in Canadian utility stocks?

A 103 My ex post risk premium studies provide evidence that investors require an equity return that is at least 6.7 percentage points above the interest rate on long-term Canada bonds. The Consensus Economics forecast interest rate on long-term Canada bonds for 2013 as of May 2012 is 2.95 percent. Adding a 6.7 percentage point risk premium to an expected yield of 2.95 percent on long-term Canada bonds and including a conservative 50-basis point allowance for flotation costs and financial flexibility produces an expected return on equity equal to 10.2 percent from my ex post risk premium studies.

Q 104 Do you have any evidence that the required equity risk premium may actually be greater than 6.7 percentage points?

A 104 Yes. I provide evidence below that the required equity risk premium increases when interest rates decline and decreases when interest rates rise. Since the expected 2.95 percent yield on long Canada bonds is significantly less than the 7.3 percent average yield on long Canada bonds over the period of my ex post risk premium studies, the current required equity risk premium should be significantly higher than the average 6.7 percent equity risk premium I obtain from my ex post risk premium studies.

### 2. Ex Ante Risk Premium Estimate

Q 105 Please describe your ex ante risk premium approach for measuring the required risk premium on an equity investment in FEI.

A 105 My ex ante risk premium method is based on studies of the expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds.

Q 106 How do you estimate the forward-looking required equity risk premium on an equity investment in utility stocks in each month of your study period.

A 106 My estimate of the required equity risk premium is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

$RP_{COMP}$ = the required risk premium on an equity investment in the comparable utilities,

$DCF_{COMP}$ = average DCF expected rate of return on a portfolio of comparable utilities; and

$I_B$ = the yield to maturity on an investment in long-term U.S. Treasury bonds.

Q 107 What comparable utilities do you use in your forward-looking equity risk premium studies?

A 107 I use two sets of comparable U.S. utilities, a natural gas utilities company group and an electric utilities company group. For my natural gas company group, I select all the utilities in Standard & Poor's natural gas company group that: (1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least two analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have investment grade S&P bond ratings. For my electric group, I use the Moody's group of 24 electric companies because they are a widely-followed group of utilities, and the use of this constant group greatly simplifies the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because my forward-looking equity risk premium studies require that the DCF model be estimated for every company in every month of the study period.

Q 108 Why do you use U.S. utilities rather than Canadian utilities in your forward-looking, or ex ante, risk premium studies?

A 108 My ex ante risk premium studies rely on the DCF model to determine the expected risk premium on utility stocks. As noted above, the DCF model requires estimates of investors' growth expectations, which are best measured from the average of analysts' growth forecasts for each company. The difficulty with using Canadian utilities is that there are very few, if any, analysts' growth forecasts available for each Canadian utility over the time periods of my studies.

Q 109 How do you test whether your forward-looking required equity risk premium estimates are sensitive to changes in interest rates?

A 109 To test whether my estimated monthly equity risk premiums are sensitive to changes in interest rates, I perform a regression analysis of the relationship between the forward-looking equity risk premium and the yield to maturity on twenty-year U.S. Treasury bonds using the equation:

$$RP_{COMP} \quad = \quad a + (b \times I_B) + e$$

where:

$RP_{COMP}$ = risk premium on comparable company group;

$I_B$ = yield to maturity on long-term U.S. Treasury bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Q 110 What risk premium estimates do you obtain from your forward-looking risk premium studies?

A 110 For my natural gas comparable group, I obtain a forward-looking risk premium equal to 8.0 percent, and for my electric utility comparable group, I obtain a forward-looking risk premium equal to approximately 7.5 percent.

Q 111 What cost of equity results do you obtain from your ex ante risk premium studies?

A 111 As described above, in the ex ante risk premium approach, one must add the expected interest rate on long-term government bonds to the estimated risk premium to calculate the cost of equity. Since FEI is a Canadian utility, I estimate the expected yield on long-term government bonds using the forecast interest rate on long-term Canada bonds at the time of my studies, 2.95 percent.  Adding this 2.95 percent interest rate to my 8.0 percent and 7.5 percent ex ante risk premium estimates, and adding a fifty-basis-point adjustment for flotation costs and financial flexibility, I obtain cost of equity estimates of 11.5 percent and 11.0 percent (3.0 + 8.0 + 0.5 = 11.5 and 3.0 + 7.5 + 0.5 = 11.0). A more detailed description of my ex ante risk premium approach and results is described in Exhibit 10, Exhibit 11, and Exhibit 24, Appendix 3.

### C. Capital Asset Pricing Model ("CAPM")

Q 112 What is the CAPM?

A 112 The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta", times the market risk premium:

*Cost of equity = Risk-free rate + Equity beta x Market risk premium*

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q 113 How do you use the CAPM to estimate the cost of equity for your proxy companies?

A 113 The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use the 2.95 percent forecasted yield to maturity on long Canada bonds. For my estimate of the company-specific risk, or beta, I use the average Value Line beta of 0.73 for my large proxy utility group. For my estimate of the expected risk premium on the market portfolio, I use the Ibbotson® SBBI® 6.6 percent risk premium on the market portfolio, which is measured from the difference between the arithmetic mean return on the S&P 500 and the income return on twenty-year Treasury bonds.

Q 114 Why do you recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return, rather than the geometric mean return, on the S&P 500?

A 114 As explained in Ibbotson® SBBI®, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[5]

Q 115 Why do you recommend that the risk premium on the market portfolio be estimated using the income return on twenty-year Treasury bonds rather than the total return on these bonds?

A 115 As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q 116 What CAPM result do you obtain when you estimate the expected return on the market portfolio from the arithmetic mean difference between the return on the market and the yield on twenty-year Treasury bonds?

A 116 I obtain a CAPM estimate of 8.27 percent based on a risk-free rate of 2.95 percent, a beta of .73, a market risk premium of 6.6 percent, and a fifty basis point allowance for flotation costs and financial flexibility (see Exhibit 12).

---

[5] Ibbotson® SBBI® 2011 Valuation Edition Yearbook, p. 56.

Q 117 Is there any evidence from the finance literature that the CAPM may underestimate the cost of equity?

A 117 Yes. There is substantial evidence that: (1) the CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0; and (2) the CAPM is less reliable the further the estimated beta is from 1.0.

Q 118 What is the evidence that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0?

A 118 The original evidence that the CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and is less reliable the further the estimated beta is from 1.0 was presented in a paper by Black, Jensen, and Scholes (1972), "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French (1992), Fama and French (2004), Fama and MacBeth (1973), and Jegadeesh and Titman (1993).[6]

Q 119 Can you briefly summarize these articles?

---

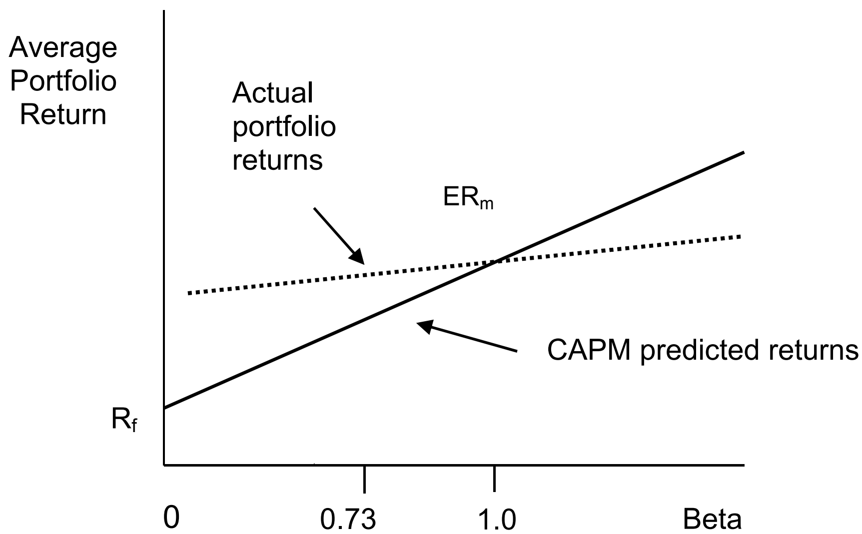
[6] Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in Studies in the Theory of Capital Markets, M. Jensen, ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," Journal of Political Economy 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence," Journal of Financial Economics 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," Journal of Financial Economics (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," Journal of Finance (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," The Journal of Economic Perspectives (Summer 2004), 18:3, pp. 25 – 46; Narasimhan Jegadeesh and Sheridan Titman, "Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency," The Journal of Finance, Vol. 48, No. 1. (Mar., 1993), pp. 65-91.

A 119 Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation

$$ER_i = R_f + \beta_i \left[ER_m - R_f\right],$$

where $ER_i$ is the expected return on security or portfolio $i$, $R_f$ is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and $\beta_i$ is a measure of the risk of investing in security or portfolio $i$ (see Figure 1 below).

**FIGURE 1**
**AVERAGE RETURNS COMPARED TO BETA**
**FOR PORTFOLIOS FORMED ON PRIOR BETA**




Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that the relationship between returns and betas is inconsistent with the relationship posited by the CAPM.

If the CAPM correctly predicts achieved returns in the marketplace, the actual portfolio returns should fall on the straight line from $R_f$ through $ER_m$. However, as described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the straight line, they generally agree that the dotted line lies above the straight line for portfolios with betas less than 1.0 and below the straight line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0.

Q 120 Do you have evidence that the CAPM tends to underestimate the cost of equity for utility companies?

A 120 Yes. Over the period 1937 to 2012, investors in the S&P Utilities Stock Index have earned an average risk premium over the yield on long-term U.S. Treasury bonds equal to 5.21 percent, while investors in the S&P 500 have earned an average risk premium over the yield on long-term U.S. Treasury bonds equal to 5.67 percent. According to the CAPM, investors in utility stocks should expect to earn a risk premium over the yield on long-term Treasury bonds equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the average risk premium on the utility portfolio to the average risk premium on the S&P 500 should equal the utility beta (that is, utility beta = average risk premium on utility stocks ÷ average risk premium S&P 500). However, the average Value Line utility beta at the time of my studies is 0.73, whereas the historical ratio of the average utility risk premium to the average S&P 500 risk premium is 0.92 (5.21 ÷ 5.67 = 0.92) (see Exhibit 13). In short, an application of the CAPM using the average 0.73 Value Line beta significantly underestimates the cost of equity for utility companies.

Q 121 What CAPM result would you obtain with a 0.92 beta, rather than the average Value Line 0.73 beta of your proxy utilities?

A 121 I would obtain a CAPM estimate of 9.52 percent, based on a risk-free rate of 2.95 percent, a beta of .92, a market risk premium of 6.6 percent, and a fifty basis point allowance for flotation costs and financial flexibility (see Exhibit 14).

Q 122 You note that, according to the CAPM, the utility beta is equal to the average or expected risk premium on utility stocks divided by the average or expected risk premium on the market index. Have you compared the average risk premiums on Canadian utility stocks to the average risk premium on the Canadian market index?

A 122 Yes. I find that the average historical risk premiums on Canadian utility stocks over the periods 1956 to 2012 and 1983 to 2012 have exceeded the average historical risk premium on the S&P TSX Composite (see Exhibit 15). Thus, the results for Canadian utilities are similar to the results for U.S. utilities in the sense that the average historical risk premiums on Canadian utility stocks are higher than would be indicated by the betas for Canadian utility stocks. These results indicate that either the short-run measured betas underestimate the long run risk of investing in Canadian utility stocks, or the CAPM is unable to predict the returns on Canadian utility stocks.

Q 123 Are factors other than those you discuss above causing CAPM estimates of the cost of equity to be unrealistically low at this time?

A 123 Yes. In addition to the reasons discussed above, the CAPM produces unrealistically low results because the CAPM results are highly sensitive to the estimate of the risk-free rate as measured by the yield on long-term government bonds. At this time, the yield on long-term government bonds is unusually low, reflecting policy decisions of Canadian and U.S. governments, the Bank of Canada, and the U.S. Federal Reserve Bank to keep interest rates low in order to stimulate their economies. The use of an unusually low risk-free rate in the CAPM is an additional factor that causes the CAPM to underestimate the cost of equity.

Q 124 What conclusions do you draw from your review of the CAPM literature and the evidence that available utility estimated betas are significantly less than the historical ratio of the utility risk premium to the risk premium on the market portfolio?

A 124 From my review of the literature, I conclude that the CAPM underestimates the cost of equity for companies with betas significantly less than 1.0 and is less reliable the further the estimated beta is from

1.0. From my review of historical risk premiums on utility stocks versus the risk premiums on the market portfolios, I conclude that either: (1) actual utility betas are significantly higher than published historical betas; or (2) the CAPM fails to explain actual utility returns in the marketplace. Thus, I conclude that the cost of equity model results from applying the CAPM should be given little or no weight in estimating FEI's cost of equity in this proceeding.

### D. Cost of Equity Conclusion

Q 125 Based on your application of the DCF, risk premium, and CAPM methods to your comparable risk companies, what is your conclusion regarding your comparable risk companies' cost of equity?

A 125 I conclude that my comparable utilities' cost of equity is 10.5 percent based on my application of the DCF, Ex Post Risk Premium, and Ex Ante Risk Premium methods to my proxy groups of utilities (see Table 3). For the reasons expressed above, I give no weight to the results of the CAPM.

**TABLE 3**
**SUMMARY OF COST OF EQUITY RESULTS**

| METHOD | MODEL RESULT |
|---|---|
| Discounted Cash Flow | 10.15 |
| Ex Post Risk Premium | 10.15 |
| Ex Ante Risk Premium | 11.25 |
| Average | 10.5 |

## VI. Allowed ROEs and Equity Ratios for Comparable Risk Utilities

Q 126 Do you have evidence on recent allowed rates of return on equity for U.S. utilities?

A 126 Yes. I have evidence on recent allowed rates of return on equity for U.S. natural gas and electric utilities from January 2010 through June 2012. Since January 2010, the average allowed ROE for natural gas utilities has been 10.1 percent, and for electric utilities, 10.5 percent (see Exhibit 16 and Exhibit 17).

Q 127 Why do you examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities?

A 127 I examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities because: (1) there are significantly more allowed ROE and equity ratio decisions for U.S. utilities than for Canadian utilities; (2) U.S. utilities are broadly comparable in risk to Canadian utilities; and (3) information on U.S. allowed ROEs and equity ratios provide an independent test of the fairness of the allowed ROEs and equity ratios for Canadian utilities such as FEI.

Q 128 Are allowed rates of return on equity the best measure of the cost of equity at each point in time?

A 128 No. Since the cost of equity is determined by investors in the marketplace, not by regulators, the cost of equity is best measured using market models such as the equity risk premium and the discounted cash flow model. However, as noted above, because allowed rates of return are based on regulators' judgments regarding the cost of equity and fair rate of return, they provide additional information on the reasonableness of FEI's recommended ROE.

Q 129 How do the approved equity ratios for U.S. utilities compare to FEI's current 40 percent allowed equity ratio?

A 129 The average approved equity ratio for U.S. natural gas and electric utilities during the period January 2010 through June 2012 is 49 percent (see Exhibit 18 and Exhibit 19). Thus, the average approved equity ratio for U.S. utilities is significantly higher than FEI's current 40 percent allowed equity ratio.

Q 130 How does FEI's current 40 percent allowed equity ratio compare to the approved equity ratios for other Canadian gas and electric distribution utilities?

A 130 FEI's requested equity ratio is approximately equal to the average approved equity ratio of Canadian gas and electric distribution utilities (see TABLE 4).

**TABLE 4**
**DEEMED EQUITY RATIOS FOR CANADIAN UTILITIES**

| Company | Deemed Equity Ratio |
|---|---|
| AltaGas | 43% |
| ATCO Electric Disco | 39% |
| ATCO Gas | 39% |
| Enbridge Gas | 36% |
| ENMAX Disco | 41% |
| EPCOR Disco | 41% |
| FortisAlberta | 41% |
| Gaz Metro | 38.5% |
| Gaziföre | 38.5% |
| Heritage Gas Ltd. | 45% |
| Newfoundland Power | 45% |
| Nova Scotia Power | 40% |
| Pacific Northern Gas | 40% - 45% |
| Terasen (FortisBC Energy) | 40% |
| Union | 36% |

Q 131 How does FEI's current 40 percent allowed equity ratio compare to the market value equity ratios for your comparable groups of U.S. utilities at May 2012?

A 131 The average market value equity ratio for my comprehensive group of U.S. utilities at May 2012 is 60 percent, and for my smaller group of U.S. utilities, 62 percent (see Exhibit 20 and Exhibit 21). Thus, FEI's allowed 40 percent allowed equity ratio is significantly less than the average market value equity ratios for my groups of U.S. utilities.

Q 132 Why do you present evidence on market value equity ratios for U.S. utilities as well as evidence on book value equity ratios?

A 132 I present evidence on market value equity ratios as well as book value equity ratios because financial risk depends on the market value percentages of debt and equity in a company's capital structure rather than on the book value percentages of debt and equity in the company's capital structure.

Q 133 What conclusions do you draw from your evidence that allowed ROEs and equity ratios for comparable U.S. utilities are significantly higher than FEI's allowed ROE and equity ratio?

A 133 My evidence on allowed ROEs and allowed equity ratios for U.S. utilities provides support for the conclusion that FEI's allowed ROE in combination with its allowed equity ratio produces a return that fails to satisfy the fair rate of return standard.

## VII. The Formula Approach to Setting FEI's ROE

Q 134 The BCUC used a formula approach to setting FEI's allowed ROE from 1994 to 2009. Why did the Commission eliminate the formula approach to setting FEI's allowed ROE in its 2009 ROE decision?

A 134 The Commission eliminated the formula approach in its 2009 ROE decision because it determined that the result of its ROE Formula did not meet the fair return standard at that time. As it stated:

> The Commission considered evidence on whether the existing automatic adjustment mechanism used in the determination of the ROE of TGI, TGVI and TGW still met the fair return standard and determined that it did not. The automatic adjustment mechanism would only have produced an ROE of 8.43 percent for TGI in 2010 compared to the 9.50 percent determined by the Commission. The Commission has accordingly directed that the automatic adjustment mechanism be eliminated. However, it has also directed TGI to complete its study of alternative formulae and report to the Commission by December 31, 2010. [2009 Decision at page ii]

Q 135 What was the Commission's most recent ROE Formula at the time of its 2009 ROE decision?

A 135 The Commission's ROE Formula was given by the equation:

$$ROE = 9.145\% - [0.75 \times (5.25\% - YLD)]$$

where:

- 9.145 was the most recent approved return on equity;
- 0.75 is the adjustment coefficient for the change in the forecast risk-free rate;
- 5.25 was the previous forecast long-term Canada bond yield; and
- YLD is the current forecast long-term Canada bond yield.

I note that the 0.75 adjustment coefficient suggests that FEI's required ROE increases by seventy-five basis points when the forecasted long-term Canada bond yield increases by one hundred basis points and declines by seventy-five basis points when the forecasted long-term Canada bond yield decreases by one hundred basis points.

Q 136 How is the forecast yield on long Canada bonds determined in the ROE formula?

A 136 The forecast yield on long Canada bonds is determined by adding the average of the three-month and twelve-month forecast of ten-year Government of Canada Bonds as published by Consensus Forecasts to the average observed spread between ten-year and thirty-year Government of Canada Bonds for all trading days in the preceding month.

Q 137 What is the forecast yield on long-term Canada bonds as of May 2012?

A 137 At May 2012, the forecast yield on long Canada bonds is 2.95 percent.

Q 138 Using a 2.95 percent forecast yield on long-term Canada bonds, what ROE is obtained using the Commission's previous ROE Formula?

A 138 The Commission's previous ROE Formula produces an ROE equal to 7.42 percent. This result is calculated as follows: 7.42 = 9.145 - [0.75 x (5.25 – 2.95.)].

Q 139 What equity risk premium is suggested by the ROE Formula?

A 139 The ROE Formula indicates an equity risk premium equal to 4.47 percent (7.42 – 2.95 = 4.47).

Q 140 Have you performed any tests of the fairness of the 7.42 percent allowed ROE provided by the Commission's previous ROE Formula?

A 140 Yes. I have performed tests of the fairness of the 7.42 percent ROE that would be provided by the Commission's previous ROE Formula. First, I have examined evidence on the experienced returns achieved by equity investors in two groups of Canadian utilities compared to interest rates on long-term Canada bonds. My studies indicate that the average experienced equity risk premium on an investment in Canadian utility stocks, 6.7 percent (see Table 2 above), is 223 basis points higher than the 4.47 percent risk premium produced by the previous ROE Formula. This evidence supports the conclusion that the Commission's previous ROE Formula would not provide a fair ROE for FEI.

Second, I have examined evidence on my comparable utilities' cost of equity as measured by the DCF, ex post risk premium, and ex ante risk premium models. From this evidence, I conclude that FEI's cost of equity is approximately 10.5 percent. My estimate of FEI's cost of equity is approximately 300 basis points higher than the 7.42 percent allowed ROE that would be provided by the Commission's previous ROE Formula.

Third, I have examined evidence on the allowed rates of return on equity and allowed common equity ratios for U.S. electric and natural gas utilities. My studies indicate that average allowed rates of return on equity for U.S. utilities since 2010 are in the range 10.1 percent to 10.5 percent, and the average allowed equity ratio is approximately 49 percent. Since the Commission's previous ROE Formula currently would produce a 7.42 percent ROE on an allowed equity ratio of 40 percent (see Section VI above), this evidence supports the conclusion that the ROE Formula would fail to provide a return that is commensurate with returns on other investments of comparable risk.

## VIII. Summary and Recommendations

Q 141 Please summarize your written evidence in this proceeding.

A 141 My written evidence may be summarized as follows:

1. The business risk of Canadian utilities such as FEI is approximately equal to the business risk of the average U.S. utility, while the financial risk of Canadian utilities, as measured by their equity ratios, is greater than the financial risk of the average U.S. utility.
2. It is reasonable to use information on required ROEs for both Canadian and U.S. utilities to estimate FEI's cost of equity because: (i) the sample of publicly-traded Canadian regulated utilities is significantly smaller than the sample of publicly-traded U.S. regulated utilities; (ii) the average publicly-traded U.S. utility is more involved in traditional utility operations than the average publicly-traded Canadian utility; and (iii) the data required to estimate the cost of equity is more readily available for U.S. utilities than for Canadian utilities.
3. The cost of equity for investments in comparable risk Canadian and U.S. utilities is 10.5 percent based on DCF, Ex Post Risk Premium, and Ex Ante Risk Premium studies.

4. Recent average allowed returns on equity for U.S. utilities are in the range 10.1 percent to 10.5 percent.
5. Recent average allowed equity ratios for U.S. utilities are approximately 49 percent, whereas the allowed equity ratio for FEI is 40 percent.
6. Recent average market value equity ratios for U.S. utilities are in the range 60 percent to 62 percent.

Q 142 What conclusion do you reach from this evidence?

A 142 I conclude that FEI's current allowed rate of return on equity and deemed equity ratio produce an allowed return on rate base that is significantly less than the overall rate of return that investors could earn on other investments of similar risk.

Q 143 Based on your evidence regarding average allowed ROEs and equity ratios for U.S. utilities, what is your estimate of the average allowed rate of return on rate base for comparable risk U.S. utilities?

A 143 I estimate that the average allowed rate of return on rate base for U.S. utilities is approximately 7.7 percent, based on a conservative allowed rate of return on equity of 10.0 percent (see Table 5).

**TABLE 5**
**ESTIMATE OF AVERAGE ALLOWED RETURN ON RATE BASE FOR U.S. UTILITIES**

| CAPITAL COMPONENT | % TOTAL | COST RATE | WEIGHTED COST |
|---|---|---|---|
| Debt | 51.00% | 5.5% | 2.81% |
| Equity | 49.00% | 10.0% | 4.90% |
| Total | 100.00% | | 7.71% |

Q 144 Assuming that FEI's recommended 40.0 percent equity ratio is adopted, what allowed ROE would produce an overall rate of return of 7.7 percent?

A 144 As shown below, an allowed ROE of approximately 11 percent would produce an overall return of 7.7 percent on a deemed equity ratio of 40 percent (see Table 6).

**TABLE 6**
**ALTERNATIVE COST OF EQUITY AND EQUITY RATIO THAT PRODUCES A 7.7 PERCENT ALLOWED RETURN ON RATE BASE**

| CAPITAL COMPONENT | % TOTAL | COST RATE | WEIGHTED COST |
|---|---|---|---|
| Debt | 60.00% | 5.50% | 3.30% |
| Equity | 40.00% | 11.01% | 4.41% |
| Total | 100.00% | | 7.71% |

Q 145 What is your specific recommendation regarding the rate of return on equity and equity percentage for FEI?

A 145 I conservatively recommend that FEI be awarded an allowed ROE of 10.5 percent on an equity base of 40 percent.

Q 146 Does this conclude your written evidence?

A 146 Yes, it does.

**EXHIBIT 1**
**SEGMENT INFORMATION**
**BMO CM CANADIAN UTILITIES COMPANIES**

| **CANADIAN UTILITIES LIMITED** | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| Segment Assets ($Canadian millions) | | | | | | |
| Year | Total | Utilities | Energy | ATCO Australia | Corporate and Other | Intersegment Eliminations |
| 2011 | $11,696 | $7,903 | $1,891 | $1,340 | $728 | -$166 |
| | | | | | | |
| Percentage of Total Assets | | | | | | |
| Year | Total | Utilities | Energy | ATCO Australia | Corporate and Other | Intersegment Eliminations |
| 2011 | 100.00% | 68% | 16% | 11% | 6% | -1% |

**SEGMENT INFORMATION**
**BMO CM CANADIAN UTILITIES COMPANIES**

| EMERA INCORPORATED | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| Segment Assets ($Canadian millions) | | | | | | |
| Year | Total | NSPI | Maine Utility Operations | Caribbean Utility Operations | Brunswick Pipeline | Other |
| 2011 | $6,924 | $3,897 | $963 | $849 | $546 | $669 |
| | | | | | | |
| Percentage of Total Assets | | | | | | |
| Year | Total | NSPI | Maine Utility Operations | Caribbean Utility Operations | Brunswick Pipeline | Other |
| 2011 | 100.00% | 56% | 14% | 12% | 8% | 10% |

**SEGMENT INFORMATION**
**BMO CM CANADIAN UTILITIES COMPANIES**

| **ENBRIDGE INC.** | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| Segment Assets ($Canadian millions) | | | | | | |
| Year | Total | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing, & Energy Services | Sponsored Investments | Corporate |
| 2011 | $30,220 | $11,508 | $7,594 | $5,536 | $3,833 | $1,749 |
| | | | | | | |
| Percentage of Total Assets | | | | | | |
| Year | Total | Liquids Pipelines | Gas Distribution | Gas Pipelines, Processing, & Energy Services | Sponsored Investments | Corporate |
| 2011 | 100.00% | 38% | 25% | 18% | 13% | 6% |

**SEGMENT INFORMATION**
**BMO CM CANADIAN UTILITIES COMPANIES**

| **FORTIS INC.** | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| Segment Assets ($Canadian millions) | | | | | | |
| Year | Total | Regulated Gas Utilities - Canadian | Regulated Electric Utilities - Canadian | Regulated Electric Utilities - Caribbean | Non-Regulated - Fortis Generation | Non-Regulated Fortis Properties |
| 2011 | $13,471 | $5,316 | $6,143 | $856 | $542 | $614 |
| | | | | | | |
| Percentage of Total Assets | | | | | | |
| Year | Total | Regulated Gas Utilities - Canadian | Regulated Electric Utilities - Canadian | Regulated Electric Utilities - Caribbean | Non-Regulated - Fortis Generation | Non-Regulated Fortis Properties |
| 2011 | 100.00% | 39% | 46% | 6% | 4% | 5% |

**SEGMENT INFORMATION**
**BMO CM CANADIAN UTILITIES COMPANIES**

| **TRANSCANADA CORPORATION** | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| Segment Assets ($Canadian millions) | | | | | |
| Year | Total | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate |
| 2011 | $48,995 | $23,669 | $9,439 | $14,276 | $1,611 |
| | | | | | |
| Percentage of Total Assets | | | | | |
| Year | Total | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate |
| 2011 | 100.00% | 48% | 19% | 29% | 3% |

**EXHIBIT 2**
**SEGMENT INFORMATION**
**S&P/TSX UTILITIES**

| **ATCO LIMITED** | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| Segment Assets ($Canadian millions) | | | | | | |
| Year | Total | Structures & Logistics | Utilities | Energy | ATCO Australia | Corporate & Other |
| 2011 | $12,555 | $721 | $7,903 | $1,891 | $1,340 | $700 |
| | | | | | | |
| Percentage of Total Assets | | | | | | |
| Year | Total | Structures & Logistics | Utilities | Energy | ATCO Australia | Corporate & Other |
| 2011 | 100.00% | 6% | 63% | 15% | 11% | 6% |

**EXHIBIT 2**
**SEGMENT INFORMATION**
**S&P/TSX UTILITIES**

| **ALGONQUIN POWER & UTILITIES CORP.** | | | | |
|---|---|---|---|---|
| | | | | |
| | | | | |
| Segment Assets ($Canadian millions) | | | | |
| Year | Total | Algonquin Power | Liberty Utilities | Corporate |
| 2011 | $1,283 | $659 | $441 | $183 |
| | | | | |
| Percentage of Total Assets | | | | |
| Year | Total | Algonquin Power | Liberty Utilities | Corporate |
| 2011 | 100.00% | 51% | 34% | 14% |

**EXHIBIT 3**
**PERCENT OF TOTAL ASSETS**
**FOR REGULATED UTILITY SERVICES**
**COMPREHENSIVE U.S. UTILITY GROUP**

| LINE | COMPANY | STATUS | % REGULATED |
|---|---|---|---|
| 1 | AGL Resources | R | 80% |
| 2 | Alliant Energy | R | 87% |
| 3 | Amer. Elec. Power | R | 97% |
| 4 | Atmos Energy | R | 90% |
| 5 | CenterPoint Energy | MR | 72% |
| 6 | CMS Energy Corp. | R | 89% |
| 7 | Consol. Edison | R | 89% |
| 8 | Dominion Resources | MR | 63% |
| 9 | DTE Energy | R | 81% |
| 10 | Duke Energy | MR | 77% |
| 11 | FirstEnergy Corp. | MR | 65% |
| 12 | G't Plains Energy | R | 104% |
| 13 | Hawaiian Elec. | D | 48% |
| 14 | NextEra Energy | MR | 54% |
| 15 | NiSource Inc. | MR | 58% |
| 16 | Northeast Utilities | R | 95% |
| 17 | Northwest Nat. Gas | R | 90% |
| 18 | Pepco Holdings | MR | 73% |
| 19 | Piedmont Natural Gas | R | 97% |
| 20 | Pinnacle West Capital | R | 99% |
| 21 | PNM Resources | R | 94% |
| 22 | Portland General | R | 100% |
| 23 | Public Serv. Enterprise | MR | 56% |
| 24 | SCANA Corp. | MR | 77% |
| 25 | Sempra Energy | MR | 66% |
| 26 | Southern Co. | R | 93% |
| 27 | TECO Energy | R | 94% |
| 28 | Vectren Corp. | R | 98% |
| 29 | Westar Energy | R | 100% |
| 30 | WGL Holdings Inc. | R | 89% |
| 31 | Wisconsin Energy | R | 92% |
| 32 | Xcel Energy Inc. | R | 95% |
| 33 | Average | | 83% |

**EXHIBIT 4**
**PERCENT OF TOTAL ASSETS**
**FOR REGULATED UTILITY SERVICES**
**U.S. GROUP WITH MOSTLY REGULATED ASSETS**
**AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB**

| LINE | COMPANY | STATUS | % REGULATED |
|---|---|---|---|
| 1 | AGL Resources | R | 80% |
| 2 | Alliant Energy | R | 87% |
| 3 | Amer. Elec. Power | R | 97% |
| 4 | Atmos Energy | R | 90% |
| 5 | Consol. Edison | R | 89% |
| 6 | DTE Energy | R | 81% |
| 7 | G't Plains Energy | R | 104% |
| 8 | Northeast Utilities | R | 95% |
| 9 | Northwest Nat. Gas | R | 90% |
| 10 | Piedmont Natural Gas | R | 97% |
| 11 | Pinnacle West Capital | R | 99% |
| 12 | Portland General | R | 100% |
| 13 | Southern Co. | R | 93% |
| 14 | TECO Energy | R | 94% |
| 15 | Vectren Corp. | R | 98% |
| 16 | Westar Energy | R | 100% |
| 17 | WGL Holdings Inc. | R | 89% |
| 18 | Wisconsin Energy | R | 92% |
| 19 | Xcel Energy Inc. | R | 95% |
| 20 | Average | | 93% |

**EXHIBIT 5**
**STANDARD & POOR'S BOND RATINGS**
**COMPREHENSIVE U.S. UTILITY GROUP**

| LINE NO. | COMPANY | SAFETY RANK | S&P BOND RATING | S&P BOND RATING (NUMERICAL) |
|---|---|---|---|---|
| 1 | AGL Resources | 1 | BBB+ | 6 |
| 2 | Alliant Energy | 2 | BBB+ | 6 |
| 3 | Amer. Elec. Power | 3 | BBB | 7 |
| 4 | Atmos Energy | 2 | BBB+ | 6 |
| 5 | CenterPoint Energy | 3 | BBB+ | 6 |
| 6 | CMS Energy Corp. | 3 | BBB- | 8 |
| 7 | Consol. Edison | 1 | A- | 5 |
| 8 | Dominion Resources | 2 | A- | 5 |
| 9 | DTE Energy | 3 | BBB+ | 6 |
| 10 | Duke Energy | 2 | A- | 5 |
| 11 | FirstEnergy Corp. | 2 | BBB- | 8 |
| 12 | G't Plains Energy | 3 | BBB | 7 |
| 13 | Hawaiian Elec. | 3 | BBB- | 8 |
| 14 | NextEra Energy | 2 | A- | 5 |
| 15 | NiSource Inc. | 3 | BBB- | 8 |
| 16 | Northeast Utilities | 2 | A- | 5 |
| 17 | Northwest Nat. Gas | 1 | A+ | 3 |
| 18 | Pepco Holdings | 3 | BBB+ | 6 |
| 19 | Piedmont Natural Gas | 2 | A | 4 |
| 20 | Pinnacle West Capital | 2 | BBB | 7 |
| 21 | PNM Resources | 3 | BBB- | 8 |
| 22 | Portland General | 2 | BBB | 7 |
| 23 | Public Serv. Enterprise | 2 | BBB | 7 |
| 24 | SCANA Corp. | 2 | BBB+ | 6 |
| 25 | Sempra Energy | 2 | BBB+ | 6 |
| 26 | Southern Co. | 1 | A | 4 |
| 27 | TECO Energy | 2 | BBB+ | 6 |
| 28 | Vectren Corp. | 2 | A- | 5 |
| 29 | Westar Energy | 2 | BBB | 7 |
| 30 | WGL Holdings Inc. | 1 | AA- | 2 |
| 31 | Wisconsin Energy | 1 | A- | 5 |
| 32 | Xcel Energy Inc. | 2 | A- | 5 |
| 33 | Average | 2 | BBB+ | 5.9 |

**STANDARD & POOR'S BOND RATINGS
SMALLER U.S. UTILITY GROUP WITH MOSTLY REGULATED ASSETS
AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB**

| LINE | COMPANY | SAFETY RANK | S&P BOND RATING | S&P BOND RATING (NUMERICAL) |
|---|---|---|---|---|
| 1 | AGL Resources | 1 | BBB+ | 6 |
| 2 | Alliant Energy | 2 | BBB+ | 6 |
| 3 | Amer. Elec. Power | 3 | BBB | 7 |
| 4 | Atmos Energy | 2 | BBB+ | 6 |
| 5 | Consol. Edison | 1 | A- | 5 |
| 6 | DTE Energy | 3 | BBB+ | 6 |
| 7 | G't Plains Energy | 3 | BBB | 7 |
| 8 | Northeast Utilities | 2 | A- | 5 |
| 9 | Northwest Nat. Gas | 1 | A+ | 3 |
| 10 | Piedmont Natural Gas | 2 | A | 4 |
| 11 | Pinnacle West Capital | 2 | BBB | 7 |
| 12 | Portland General | 2 | BBB | 7 |
| 13 | Southern Co. | 1 | A | 4 |
| 14 | TECO Energy | 2 | BBB+ | 6 |
| 15 | Vectren Corp. | 2 | A- | 5 |
| 16 | Westar Energy | 2 | BBB | 7 |
| 17 | WGL Holdings Inc. | 1 | AA- | 2 |
| 18 | Wisconsin Energy | 1 | A- | 5 |
| 19 | Xcel Energy Inc. | 2 | A- | 5 |
| 20 | Average | 1.8 | A- | 5.4 |

**EXHIBIT 6**
**SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS**
**FOR COMPREHENSIVE GROUP OF U.S. UTILITIES**

| LINE | COMPANY | $D_0$ | $P_0$ | GROWTH | MODEL RESULT |
|---|---|---|---|---|---|
| 1 | AGL Resources | 0.460 | 38.823 | 3.57% | 8.6% |
| 2 | Alliant Energy | 0.450 | 43.651 | 6.35% | 10.8% |
| 3 | Amer. Elec. Power | 0.470 | 38.183 | 3.53% | 8.8% |
| 4 | Atmos Energy | 0.345 | 31.912 | 4.37% | 9.0% |
| 5 | CenterPoint Energy | 0.203 | 19.625 | 4.18% | 8.5% |
| 6 | CMS Energy Corp. | 0.240 | 22.253 | 5.96% | 10.4% |
| 7 | Consol. Edison | 0.605 | 58.667 | 3.15% | 7.5% |
| 8 | Dominion Resources | 0.528 | 51.337 | 5.40% | 9.7% |
| 9 | DTE Energy | 0.588 | 55.486 | 4.29% | 8.9% |
| 10 | Duke Energy | 0.250 | 21.202 | 3.51% | 8.5% |
| 11 | FirstEnergy Corp. | 0.550 | 46.100 | 3.15% | 8.2% |
| 12 | G't Plains Energy | 0.213 | 19.975 | 9.75% | 14.6% |
| 13 | Hawaiian Elec. | 0.310 | 25.940 | 8.03% | 13.5% |
| 14 | NextEra Energy | 0.600 | 62.512 | 5.38% | 9.3% |
| 15 | NiSource Inc. | 0.230 | 24.392 | 9.63% | 14.0% |
| 16 | Northeast Utilities | 0.294 | 36.393 | 6.06% | 9.4% |
| 17 | Northwest Nat. Gas | 0.445 | 45.405 | 3.25% | 7.4% |
| 18 | Pepco Holdings | 0.270 | 18.858 | 4.85% | 11.1% |
| 19 | Piedmont Natural Gas | 0.300 | 30.656 | 4.55% | 8.7% |
| 20 | Pinnacle West Capital | 0.525 | 47.646 | 6.22% | 11.1% |
| 21 | PNM Resources | 0.145 | 18.419 | 9.25% | 12.5% |
| 22 | Portland General | 0.265 | 25.027 | 4.13% | 8.7% |
| 23 | Public Serv. Enterprise | 0.355 | 30.577 | 3.60% | 8.4% |
| 24 | SCANA Corp. | 0.495 | 45.333 | 4.63% | 9.3% |
| 25 | Sempra Energy | 0.600 | 61.933 | 7.05% | 10.7% |
| 26 | Southern Co. | 0.490 | 45.113 | 5.58% | 10.2% |
| 27 | TECO Energy | 0.220 | 17.628 | 4.11% | 9.4% |
| 28 | Vectren Corp. | 0.350 | 29.022 | 5.00% | 10.2% |
| 29 | Westar Energy | 0.330 | 27.859 | 5.80% | 10.9% |
| 30 | WGL Holdings Inc. | 0.400 | 40.022 | 4.60% | 8.8% |
| 31 | Wisconsin Energy | 0.300 | 35.760 | 5.35% | 8.6% |
| 32 | Xcel Energy Inc. | 0.260 | 26.843 | 5.27% | 9.5% |
| 33 | Average | | | | 9.8% |
| 34 | Financial flexibility | | | | 0.5% |
| 35 | Model Result | | | | 10.3% |

Notes:

| | | |
|---|---|---|
| $d_0$ | = | Most recent quarterly dividend |
| $d_1,d_2,d_3,d_4$ | = | Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g) |
| $P_0$ | = | Average of the monthly high and low stock prices during the three months ending May 2012 per Thomson Reuters |
| g | = | I/B/E/S forecast of future earnings growth May 2012 |
| k | = | Cost of equity using the quarterly version of the DCF model: |

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

**EXHIBIT 7**
**SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS**
**FOR SMALLER GROUP OF U.S. UTILITIES WITH MOSTLY REGULATED ASSETS**
**AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB**

| LINE | COMPANY | $D_0$ | $P_0$ | GROWTH | MODEL RESULT |
|---|---|---|---|---|---|
| 1 | AGL Resources | 0.460 | 38.823 | 3.57% | 8.6% |
| 2 | Alliant Energy | 0.450 | 43.651 | 6.35% | 10.8% |
| 3 | Amer. Elec. Power | 0.470 | 38.183 | 3.53% | 8.8% |
| 4 | Atmos Energy | 0.345 | 31.912 | 4.37% | 9.0% |
| 5 | Consol. Edison | 0.605 | 58.667 | 3.15% | 7.5% |
| 6 | DTE Energy | 0.588 | 55.486 | 4.29% | 8.9% |
| 7 | G't Plains Energy | 0.213 | 19.975 | 9.75% | 14.6% |
| 8 | Northeast Utilities | 0.294 | 36.393 | 6.06% | 9.4% |
| 9 | Northwest Nat. Gas | 0.445 | 45.405 | 3.25% | 7.4% |
| 10 | Piedmont Natural Gas | 0.300 | 30.656 | 4.55% | 8.7% |
| 11 | Pinnacle West Capital | 0.525 | 47.646 | 6.22% | 11.1% |
| 12 | Portland General | 0.265 | 25.027 | 4.13% | 8.7% |
| 13 | Southern Co. | 0.490 | 45.113 | 5.58% | 10.2% |
| 14 | TECO Energy | 0.220 | 17.628 | 4.11% | 9.4% |
| 15 | Vectren Corp. | 0.350 | 29.022 | 5.00% | 10.2% |
| 16 | Westar Energy | 0.330 | 27.859 | 5.80% | 10.9% |
| 17 | WGL Holdings Inc. | 0.400 | 40.022 | 4.60% | 8.8% |
| 18 | Wisconsin Energy | 0.300 | 35.760 | 5.35% | 8.6% |
| 19 | Xcel Energy Inc. | 0.260 | 26.843 | 5.27% | 9.5% |
| 20 | Average | | | | 9.5% |
| 21 | Financial flexibility | | | | 0.5% |
| 22 | Model Result | | | | 10.0% |

Notes:

| | | |
|---|---|---|
| $d_0$ | = | Most recent quarterly dividend. |
| $d_1, d_2, d_3, d_4$ | = | Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g) |
| $P_0$ | = | Average of the monthly high and low stock prices during the three months ending May 2012 per Thomson Reuters |
| g | = | I/B/E/S forecast of future earnings growth May 2012 |
| k | = | Cost of equity using the quarterly version of the DCF model |

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

**EXHIBIT 8**
**EXPERIENCED RISK PREMIUMS ON**
**S&P/TSX CANADIAN UTILITIES STOCK INDEX**
**1956—2011**

| LINE | YEAR | S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN | YIELD LONG-TERM CANADA BOND | RISK PREMIUM |
|---|---|---|---|---|
| 1 | 1956 | 0.17 | 3.63 | -3.45 |
| 2 | 1957 | -3.43 | 4.11 | -7.54 |
| 3 | 1958 | 9.81 | 4.15 | 5.66 |
| 4 | 1959 | 0.21 | 5.08 | -4.86 |
| 5 | 1960 | 26.81 | 5.19 | 21.62 |
| 6 | 1961 | 19.17 | 5.05 | 14.12 |
| 7 | 1962 | -0.72 | 5.11 | -5.83 |
| 8 | 1963 | 6.19 | 5.09 | 1.10 |
| 9 | 1964 | 21.59 | 5.18 | 16.41 |
| 10 | 1965 | 4.23 | 5.21 | -0.98 |
| 11 | 1966 | -13.17 | 5.69 | -18.86 |
| 12 | 1967 | 5.07 | 5.94 | -0.87 |
| 13 | 1968 | 7.41 | 6.75 | 0.66 |
| 14 | 1969 | -8.62 | 7.58 | -16.20 |
| 15 | 1970 | 23.34 | 7.91 | 15.43 |
| 16 | 1971 | 4.29 | 6.95 | -2.66 |
| 17 | 1972 | -0.44 | 7.23 | -7.68 |
| 18 | 1973 | -4.14 | 7.56 | -11.70 |
| 19 | 1974 | 14.38 | 8.90 | 5.48 |
| 20 | 1975 | 5.75 | 9.04 | -3.28 |
| 21 | 1976 | 15.02 | 9.18 | 5.84 |
| 22 | 1977 | 19.00 | 8.70 | 10.30 |
| 23 | 1978 | 27.28 | 9.27 | 18.01 |
| 24 | 1979 | 12.61 | 10.21 | 2.40 |
| 25 | 1980 | 5.74 | 12.48 | -6.74 |
| 26 | 1981 | -0.55 | 15.22 | -15.77 |
| 27 | 1982 | 35.90 | 14.26 | 21.65 |
| 28 | 1983 | 40.97 | 11.79 | 29.17 |
| 29 | 1984 | 24.31 | 12.75 | 11.56 |
| 30 | 1985 | 10.04 | 11.04 | -1.00 |
| 31 | 1986 | 11.48 | 9.52 | 1.96 |
| 32 | 1987 | 1.07 | 9.95 | -8.88 |
| 33 | 1988 | 5.63 | 10.22 | -4.59 |
| 34 | 1989 | 22.07 | 9.92 | 12.15 |
| 35 | 1990 | 0.58 | 10.85 | -10.28 |
| 36 | 1991 | 27.02 | 9.76 | 17.25 |
| 37 | 1992 | -2.24 | 8.77 | -11.00 |

| LINE | YEAR | S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN | YIELD LONG-TERM CANADA BOND | RISK PREMIUM |
|---|---|---|---|---|
| 38 | 1993 | 23.52 | 7.85 | 15.67 |
| 39 | 1994 | -6.04 | 8.63 | -14.68 |
| 40 | 1995 | 18.44 | 8.28 | 10.16 |
| 41 | 1996 | 32.68 | 7.50 | 25.18 |
| 42 | 1997 | 37.33 | 6.42 | 30.91 |
| 43 | 1998 | 36.55 | 5.47 | 31.09 |
| 44 | 1999 | -27.14 | 5.69 | -32.83 |
| 45 | 2000 | 50.06 | 5.89 | 44.17 |
| 46 | 2001 | 10.83 | 5.78 | 5.05 |
| 47 | 2002 | 6.33 | 5.66 | 0.67 |
| 48 | 2003 | 24.94 | 5.28 | 19.66 |
| 49 | 2004 | 9.42 | 5.08 | 4.34 |
| 50 | 2005 | 38.29 | 4.39 | 33.90 |
| 51 | 2006 | 7.01 | 4.30 | 2.71 |
| 52 | 2007 | 11.89 | 4.34 | 7.55 |
| 53 | 2008 | -20.46 | 4.04 | -24.50 |
| 54 | 2009 | 19.00 | 3.89 | 15.11 |
| 55 | 2010 | 18.39 | 3.66 | 14.73 |
| 56 | 2011 | 6.47 | 3.21 | 3.26 |
| 57 | Average | 11.99 | 7.33 | 4.66 |

**EXHIBIT 9**
**EXPERIENCED RISK PREMIUMS ON BMO CAPITAL MARKETS UTILITIES STOCK DATA SET**
**1983—2011**

| LINE | YEAR | BMO CAPITAL MARKETS UTILITIES & PIPELINE TOTAL RETURN | YIELD LONG-TERM CANADA BOND | RISK PREMIUM |
|---|---|---|---|---|
| 1 | 1983 | 25.84 | 11.79 | 14.05 |
| 2 | 1984 | 6.89 | 12.75 | -5.86 |
| 3 | 1985 | 20.09 | 11.04 | 9.04 |
| 4 | 1986 | -1.22 | 9.52 | -10.74 |
| 5 | 1987 | 11.98 | 9.95 | 2.03 |
| 6 | 1988 | 6.67 | 10.22 | -3.56 |
| 7 | 1989 | 23.80 | 9.92 | 13.88 |
| 8 | 1990 | 10.00 | 10.85 | -0.86 |
| 9 | 1991 | 12.92 | 9.76 | 3.16 |
| 10 | 1992 | 0.75 | 8.77 | -8.02 |
| 11 | 1993 | 33.00 | 7.85 | 25.15 |
| 12 | 1994 | -1.22 | 8.63 | -9.85 |
| 13 | 1995 | 15.13 | 8.28 | 6.85 |
| 14 | 1996 | 31.66 | 7.50 | 24.15 |
| 15 | 1997 | 50.16 | 6.42 | 43.74 |
| 16 | 1998 | 4.12 | 5.47 | -1.34 |
| 17 | 1999 | -24.11 | 5.69 | -29.80 |
| 18 | 2000 | 59.57 | 5.89 | 53.69 |
| 19 | 2001 | 16.05 | 5.78 | 10.27 |
| 20 | 2002 | 14.46 | 5.66 | 8.80 |
| 21 | 2003 | 28.74 | 5.28 | 23.46 |
| 22 | 2004 | 15.56 | 5.08 | 10.48 |
| 23 | 2005 | 33.36 | 4.39 | 28.97 |
| 24 | 2006 | 17.77 | 4.30 | 13.47 |
| 25 | 2007 | 4.90 | 4.34 | 0.57 |
| 26 | 2008 | -4.21 | 4.04 | -8.25 |
| 27 | 2009 | 20.24 | 3.89 | 16.35 |
| 28 | 2010 | 5.39 | 3.66 | 1.73 |
| 29 | 2011 | 25.89 | 3.21 | 22.68 |
| 30 | Average | 16.01 | 7.24 | 8.77 |

**EXHIBIT 10**
**COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON LONG-TERM GOVERNMENT BONDS**

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 1 | Sep-99 | 0.1124 | 0.0650 | 0.0474 |
| 2 | Oct-99 | 0.1128 | 0.0666 | 0.0462 |
| 3 | Nov-99 | 0.1158 | 0.0648 | 0.0510 |
| 4 | Dec-99 | 0.1200 | 0.0669 | 0.0531 |
| 5 | Jan-00 | 0.1186 | 0.0686 | 0.0500 |
| 6 | Feb-00 | 0.1232 | 0.0654 | 0.0578 |
| 7 | Mar-00 | 0.1274 | 0.0638 | 0.0636 |
| 8 | Apr-00 | 0.1203 | 0.0618 | 0.0585 |
| 9 | May-00 | 0.1194 | 0.0655 | 0.0539 |
| 10 | Jun-00 | 0.1209 | 0.0628 | 0.0581 |
| 11 | Jul-00 | 0.1213 | 0.0620 | 0.0593 |
| 12 | Aug-00 | 0.1197 | 0.0602 | 0.0595 |
| 13 | Sep-00 | 0.1137 | 0.0609 | 0.0528 |
| 14 | Oct-00 | 0.1143 | 0.0604 | 0.0539 |
| 15 | Nov-00 | 0.1164 | 0.0598 | 0.0566 |
| 16 | Dec-00 | 0.1140 | 0.0564 | 0.0576 |
| 17 | Jan-01 | 0.1167 | 0.0565 | 0.0602 |
| 18 | Feb-01 | 0.1176 | 0.0562 | 0.0614 |
| 19 | Mar-01 | 0.1180 | 0.0549 | 0.0631 |
| 20 | Apr-01 | 0.1208 | 0.0578 | 0.0630 |
| 21 | May-01 | 0.1254 | 0.0592 | 0.0662 |
| 22 | Jun-01 | 0.1261 | 0.0582 | 0.0679 |
| 23 | Jul-01 | 0.1269 | 0.0575 | 0.0694 |
| 24 | Aug-01 | 0.1275 | 0.0558 | 0.0717 |
| 25 | Sep-01 | 0.1294 | 0.0553 | 0.0741 |
| 26 | Oct-01 | 0.1286 | 0.0534 | 0.0752 |
| 27 | Nov-01 | 0.1268 | 0.0533 | 0.0735 |
| 28 | Dec-01 | 0.1264 | 0.0576 | 0.0688 |
| 29 | Jan-02 | 0.1246 | 0.0569 | 0.0677 |
| 30 | Feb-02 | 0.1256 | 0.0561 | 0.0695 |
| 31 | Mar-02 | 0.1221 | 0.0593 | 0.0628 |
| 32 | Apr-02 | 0.1201 | 0.0585 | 0.0616 |
| 33 | May-02 | 0.1208 | 0.0581 | 0.0627 |
| 34 | Jun-02 | 0.1225 | 0.0565 | 0.0660 |
| 35 | Jul-02 | 0.1305 | 0.0551 | 0.0754 |
| 36 | Aug-02 | 0.1269 | 0.0519 | 0.0750 |
| 37 | Sep-02 | 0.1241 | 0.0487 | 0.0754 |
| 38 | Oct-02 | 0.1258 | 0.0500 | 0.0758 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 39 | Nov-02 | 0.1210 | 0.0504 | 0.0706 |
| 40 | Dec-02 | 0.1195 | 0.0501 | 0.0694 |
| 41 | Jan-03 | 0.1166 | 0.0502 | 0.0664 |
| 42 | Feb-03 | 0.1200 | 0.0487 | 0.0713 |
| 43 | Mar-03 | 0.1179 | 0.0482 | 0.0697 |
| 44 | Apr-03 | 0.1138 | 0.0491 | 0.0647 |
| 45 | May-03 | 0.1066 | 0.0452 | 0.0614 |
| 46 | Jun-03 | 0.1019 | 0.0434 | 0.0585 |
| 47 | Jul-03 | 0.1043 | 0.0492 | 0.0551 |
| 48 | Aug-03 | 0.1034 | 0.0539 | 0.0495 |
| 49 | Sep-03 | 0.1000 | 0.0521 | 0.0479 |
| 50 | Oct-03 | 0.0981 | 0.0521 | 0.0460 |
| 51 | Nov-03 | 0.0957 | 0.0517 | 0.0440 |
| 52 | Dec-03 | 0.0919 | 0.0511 | 0.0408 |
| 53 | Jan-04 | 0.0896 | 0.0501 | 0.0395 |
| 54 | Feb-04 | 0.0892 | 0.0494 | 0.0398 |
| 55 | Mar-04 | 0.0888 | 0.0472 | 0.0416 |
| 56 | Apr-04 | 0.0900 | 0.0516 | 0.0384 |
| 57 | May-04 | 0.0935 | 0.0546 | 0.0389 |
| 58 | Jun-04 | 0.0934 | 0.0545 | 0.0389 |
| 59 | Jul-04 | 0.0927 | 0.0524 | 0.0403 |
| 60 | Aug-04 | 0.0940 | 0.0507 | 0.0433 |
| 61 | Sep-04 | 0.0925 | 0.0489 | 0.0436 |
| 62 | Oct-04 | 0.0928 | 0.0485 | 0.0443 |
| 63 | Nov-04 | 0.0894 | 0.0489 | 0.0405 |
| 64 | Dec-04 | 0.0896 | 0.0488 | 0.0408 |
| 65 | Jan-05 | 0.0900 | 0.0477 | 0.0423 |
| 66 | Feb-05 | 0.0893 | 0.0461 | 0.0432 |
| 67 | Mar-05 | 0.0894 | 0.0489 | 0.0405 |
| 68 | Apr-05 | 0.0899 | 0.0475 | 0.0424 |
| 69 | May-05 | 0.0886 | 0.0456 | 0.0430 |
| 70 | Jun-05 | 0.0888 | 0.0435 | 0.0453 |
| 71 | Jul-05 | 0.0877 | 0.0448 | 0.0429 |
| 72 | Aug-05 | 0.0878 | 0.0453 | 0.0425 |
| 73 | Sep-05 | 0.0901 | 0.0451 | 0.0450 |
| 74 | Oct-05 | 0.0911 | 0.0474 | 0.0437 |
| 75 | Nov-05 | 0.0957 | 0.0483 | 0.0474 |
| 76 | Dec-05 | 0.0956 | 0.0473 | 0.0483 |
| 77 | Jan-06 | 0.0957 | 0.0465 | 0.0492 |
| 78 | Feb-06 | 0.1048 | 0.0473 | 0.0575 |
| 79 | Mar-06 | 0.1031 | 0.0491 | 0.0540 |
| 80 | Apr-06 | 0.1050 | 0.0522 | 0.0528 |
| 81 | May-06 | 0.1063 | 0.0535 | 0.0528 |
| 82 | Jun-06 | 0.1093 | 0.0529 | 0.0564 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 83 | Jul-06 | 0.1087 | 0.0525 | 0.0562 |
| 84 | Aug-06 | 0.1050 | 0.0508 | 0.0542 |
| 85 | Sep-06 | 0.1088 | 0.0493 | 0.0595 |
| 86 | Oct-06 | 0.1052 | 0.0494 | 0.0558 |
| 87 | Nov-06 | 0.1057 | 0.0478 | 0.0579 |
| 88 | Dec-06 | 0.1050 | 0.0478 | 0.0572 |
| 89 | Jan-07 | 0.1075 | 0.0495 | 0.0580 |
| 90 | Feb-07 | 0.1065 | 0.0493 | 0.0572 |
| 91 | Mar-07 | 0.1073 | 0.0481 | 0.0592 |
| 92 | Apr-07 | 0.1021 | 0.0495 | 0.0526 |
| 93 | May-07 | 0.1047 | 0.0498 | 0.0549 |
| 94 | Jun-07 | 0.1101 | 0.0529 | 0.0572 |
| 95 | Jul-07 | 0.1108 | 0.0519 | 0.0589 |
| 96 | Aug-07 | 0.1083 | 0.0500 | 0.0583 |
| 97 | Sep-07 | 0.1056 | 0.0484 | 0.0572 |
| 98 | Oct-07 | 0.1061 | 0.0483 | 0.0578 |
| 99 | Nov-07 | 0.1093 | 0.0456 | 0.0637 |
| 100 | Dec-07 | 0.1110 | 0.0457 | 0.0653 |
| 101 | Jan-08 | 0.1171 | 0.0435 | 0.0736 |
| 102 | Feb-08 | 0.1109 | 0.0449 | 0.0660 |
| 103 | Mar-08 | 0.1144 | 0.0436 | 0.0708 |
| 104 | Apr-08 | 0.1133 | 0.0444 | 0.0689 |
| 105 | May-08 | 0.1138 | 0.0460 | 0.0678 |
| 106 | Jun-08 | 0.1112 | 0.0474 | 0.0638 |
| 107 | Jul-08 | 0.1147 | 0.0462 | 0.0685 |
| 108 | Aug-08 | 0.1165 | 0.0453 | 0.0712 |
| 109 | Sep-08 | 0.1159 | 0.0432 | 0.0727 |
| 110 | Oct-08 | 0.1249 | 0.0445 | 0.0804 |
| 111 | Nov-08 | 0.1280 | 0.0427 | 0.0853 |
| 112 | Dec-08 | 0.1270 | 0.0318 | 0.0952 |
| 113 | Jan-09 | 0.1211 | 0.0346 | 0.0865 |
| 114 | Feb-09 | 0.1237 | 0.0383 | 0.0854 |
| 115 | Mar-09 | 0.1250 | 0.0378 | 0.0872 |
| 116 | Apr-09 | 0.1230 | 0.0384 | 0.0846 |
| 117 | May-09 | 0.1206 | 0.0422 | 0.0784 |
| 118 | Jun-09 | 0.1185 | 0.0451 | 0.0734 |
| 119 | Jul-09 | 0.1142 | 0.0438 | 0.0704 |
| 120 | Aug-09 | 0.1127 | 0.0433 | 0.0694 |
| 121 | Sep-09 | 0.1122 | 0.0414 | 0.0708 |
| 122 | Oct-09 | 0.1122 | 0.0416 | 0.0706 |
| 123 | Nov-09 | 0.1166 | 0.0424 | 0.0742 |
| 124 | Dec-09 | 0.1065 | 0.0440 | 0.0625 |
| 125 | Jan-10 | 0.1082 | 0.0450 | 0.0632 |
| 126 | Feb-10 | 0.1060 | 0.0448 | 0.0612 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 127 | Mar-10 | 0.1045 | 0.0449 | 0.0596 |
| 128 | Apr-10 | 0.1081 | 0.0453 | 0.0628 |
| 129 | May-10 | 0.1062 | 0.0411 | 0.0651 |
| 130 | Jun-10 | 0.1059 | 0.0395 | 0.0664 |
| 131 | Jul-10 | 0.1049 | 0.0380 | 0.0669 |
| 132 | Aug-10 | 0.1029 | 0.0352 | 0.0677 |
| 133 | Sep-10 | 0.1031 | 0.0347 | 0.0684 |
| 134 | Oct-10 | 0.1017 | 0.0352 | 0.0665 |
| 135 | Nov-10 | 0.1023 | 0.0382 | 0.0641 |
| 136 | Dec-10 | 0.1026 | 0.0417 | 0.0609 |
| 137 | Jan-11 | 0.1018 | 0.0428 | 0.0590 |
| 138 | Feb-11 | 0.1014 | 0.0442 | 0.0572 |
| 139 | Mar-11 | 0.1017 | 0.0427 | 0.0590 |
| 140 | Apr-11 | 0.0994 | 0.0428 | 0.0566 |
| 141 | May-11 | 0.0969 | 0.0401 | 0.0568 |
| 142 | Jun-11 | 0.1017 | 0.0391 | 0.0626 |
| 143 | Jul-11 | 0.0993 | 0.0395 | 0.0598 |
| 144 | Aug-11 | 0.1023 | 0.0324 | 0.0699 |
| 145 | Sep-11 | 0.0991 | 0.0283 | 0.0708 |
| 146 | Oct-11 | 0.1006 | 0.0287 | 0.0719 |
| 147 | Nov-11 | 0.0989 | 0.0272 | 0.0717 |
| 148 | Dec-11 | 0.1000 | 0.0267 | 0.0733 |
| 149 | Jan-12 | 0.0991 | 0.0270 | 0.0721 |
| 150 | Feb-12 | 0.0963 | 0.0275 | 0.0688 |
| 151 | Mar-12 | 0.0960 | 0.0294 | 0.0666 |
| 152 | Apr-12 | 0.0968 | 0.0282 | 0.0686 |
| 153 | May-12 | 0.0967 | 0.0253 | 0.0714 |

Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 3 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

$d_0$ = Latest quarterly dividend per Value Line, Thomson Reuters

$P_0$ = Average of the monthly high and low stock prices for each month per Thomson Reuters

$g$ = I/B/E/S forecast of future earnings growth for each month

$k$ = Cost of equity using the quarterly version of the DCF model

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}}\right]^4 - 1$$

**EXHIBIT 11**
**COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN NATURAL GAS UTILITIES TO THE INTEREST RATE ON LONG-TERM GOVERNMENT BONDS**

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 1 | Jun-98 | 0.1130 | 0.0580 | 0.0550 |
| 2 | Jul-98 | 0.1162 | 0.0578 | 0.0584 |
| 3 | Aug-98 | 0.1208 | 0.0566 | 0.0642 |
| 4 | Sep-98 | 0.1247 | 0.0538 | 0.0709 |
| 5 | Oct-98 | 0.1233 | 0.0530 | 0.0703 |
| 6 | Nov-98 | 0.1185 | 0.0548 | 0.0637 |
| 7 | Dec-98 | 0.1159 | 0.0536 | 0.0623 |
| 8 | Jan-99 | 0.1168 | 0.0545 | 0.0623 |
| 9 | Feb-99 | 0.1214 | 0.0566 | 0.0648 |
| 10 | Mar-99 | 0.1227 | 0.0587 | 0.0640 |
| 11 | Apr-99 | 0.1230 | 0.0582 | 0.0648 |
| 12 | May-99 | 0.1193 | 0.0608 | 0.0585 |
| 13 | Jun-99 | 0.1180 | 0.0636 | 0.0544 |
| 14 | Jul-99 | 0.1195 | 0.0628 | 0.0567 |
| 15 | Aug-99 | 0.1193 | 0.0643 | 0.0550 |
| 16 | Sep-99 | 0.1199 | 0.0650 | 0.0549 |
| 17 | Oct-99 | 0.1205 | 0.0666 | 0.0539 |
| 18 | Nov-99 | 0.1212 | 0.0648 | 0.0564 |
| 19 | Dec-99 | 0.1249 | 0.0669 | 0.0580 |
| 20 | Jan-00 | 0.1269 | 0.0686 | 0.0583 |
| 21 | Feb-00 | 0.1310 | 0.0654 | 0.0656 |
| 22 | Mar-00 | 0.1312 | 0.0638 | 0.0674 |
| 23 | Apr-00 | 0.1287 | 0.0618 | 0.0669 |
| 24 | May-00 | 0.1264 | 0.0655 | 0.0609 |
| 25 | Jun-00 | 0.1268 | 0.0628 | 0.0640 |
| 26 | Jul-00 | 0.1289 | 0.0620 | 0.0669 |
| 27 | Aug-00 | 0.1264 | 0.0602 | 0.0662 |
| 28 | Sep-00 | 0.1233 | 0.0609 | 0.0624 |
| 29 | Oct-00 | 0.1235 | 0.0604 | 0.0631 |
| 30 | Nov-00 | 0.1228 | 0.0598 | 0.0630 |
| 31 | Dec-00 | 0.1217 | 0.0564 | 0.0653 |
| 32 | Jan-01 | 0.1238 | 0.0565 | 0.0673 |
| 33 | Feb-01 | 0.1237 | 0.0562 | 0.0675 |
| 34 | Mar-01 | 0.1251 | 0.0549 | 0.0702 |
| 35 | Apr-01 | 0.1203 | 0.0578 | 0.0625 |
| 36 | May-01 | 0.1280 | 0.0592 | 0.0688 |
| 37 | Jun-01 | 0.1281 | 0.0582 | 0.0699 |
| 38 | Jul-01 | 0.1313 | 0.0575 | 0.0738 |
| 39 | Aug-01 | 0.1301 | 0.0558 | 0.0743 |
| 40 | Sep-01 | 0.1241 | 0.0553 | 0.0688 |
| 41 | Oct-01 | 0.1243 | 0.0534 | 0.0709 |
| 42 | Nov-01 | 0.1243 | 0.0533 | 0.0710 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 43 | Dec-01 | 0.1229 | 0.0576 | 0.0653 |
| 44 | Jan-02 | 0.1211 | 0.0569 | 0.0642 |
| 45 | Feb-02 | 0.1215 | 0.0561 | 0.0654 |
| 46 | Mar-02 | 0.1165 | 0.0593 | 0.0572 |
| 47 | Apr-02 | 0.1136 | 0.0585 | 0.0551 |
| 48 | May-02 | 0.1139 | 0.0581 | 0.0558 |
| 49 | Jun-02 | 0.1146 | 0.0565 | 0.0581 |
| 50 | Jul-02 | 0.1214 | 0.0551 | 0.0663 |
| 51 | Aug-02 | 0.1208 | 0.0519 | 0.0689 |
| 52 | Sep-02 | 0.1233 | 0.0487 | 0.0746 |
| 53 | Oct-02 | 0.1224 | 0.0500 | 0.0724 |
| 54 | Nov-02 | 0.1195 | 0.0504 | 0.0691 |
| 55 | Dec-02 | 0.1191 | 0.0501 | 0.0690 |
| 56 | Jan-03 | 0.1194 | 0.0502 | 0.0692 |
| 57 | Feb-03 | 0.1206 | 0.0487 | 0.0719 |
| 58 | Mar-03 | 0.1169 | 0.0482 | 0.0687 |
| 59 | Apr-03 | 0.1137 | 0.0491 | 0.0646 |
| 60 | May-03 | 0.1103 | 0.0452 | 0.0651 |
| 61 | Jun-03 | 0.1092 | 0.0434 | 0.0658 |
| 62 | Jul-03 | 0.1103 | 0.0492 | 0.0611 |
| 63 | Aug-03 | 0.1114 | 0.0539 | 0.0575 |
| 64 | Sep-03 | 0.1104 | 0.0521 | 0.0583 |
| 65 | Oct-03 | 0.1100 | 0.0521 | 0.0579 |
| 66 | Nov-03 | 0.1066 | 0.0517 | 0.0549 |
| 67 | Dec-03 | 0.1048 | 0.0511 | 0.0537 |
| 68 | Jan-04 | 0.1037 | 0.0501 | 0.0536 |
| 69 | Feb-04 | 0.1017 | 0.0494 | 0.0523 |
| 70 | Mar-04 | 0.1014 | 0.0472 | 0.0542 |
| 71 | Apr-04 | 0.1018 | 0.0516 | 0.0502 |
| 72 | May-04 | 0.1021 | 0.0546 | 0.0475 |
| 73 | Jun-04 | 0.1013 | 0.0545 | 0.0468 |
| 74 | Jul-04 | 0.0989 | 0.0524 | 0.0465 |
| 75 | Aug-04 | 0.0986 | 0.0507 | 0.0479 |
| 76 | Sep-04 | 0.0956 | 0.0489 | 0.0467 |
| 77 | Oct-04 | 0.0954 | 0.0485 | 0.0469 |
| 78 | Nov-04 | 0.0942 | 0.0489 | 0.0453 |
| 79 | Dec-04 | 0.0950 | 0.0488 | 0.0462 |
| 80 | Jan-05 | 0.0969 | 0.0477 | 0.0492 |
| 81 | Feb-05 | 0.0958 | 0.0461 | 0.0497 |
| 82 | Mar-05 | 0.0958 | 0.0489 | 0.0469 |
| 83 | Apr-05 | 0.0969 | 0.0475 | 0.0494 |
| 84 | May-05 | 0.0961 | 0.0456 | 0.0505 |
| 85 | Jun-05 | 0.0958 | 0.0435 | 0.0523 |
| 86 | Jul-05 | 0.0948 | 0.0448 | 0.0500 |
| 87 | Aug-05 | 0.0951 | 0.0453 | 0.0498 |
| 88 | Sep-05 | 0.0963 | 0.0451 | 0.0512 |
| 89 | Oct-05 | 0.0971 | 0.0474 | 0.0497 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 90 | Nov-05 | 0.1030 | 0.0483 | 0.0547 |
| 91 | Dec-05 | 0.1026 | 0.0473 | 0.0553 |
| 92 | Jan-06 | 0.0963 | 0.0465 | 0.0498 |
| 93 | Feb-06 | 0.1108 | 0.0473 | 0.0635 |
| 94 | Mar-06 | 0.1111 | 0.0491 | 0.0620 |
| 95 | Apr-06 | 0.1082 | 0.0522 | 0.0560 |
| 96 | May-06 | 0.1038 | 0.0535 | 0.0503 |
| 97 | Jun-06 | 0.1032 | 0.0529 | 0.0503 |
| 98 | Jul-06 | 0.1071 | 0.0525 | 0.0546 |
| 99 | Aug-06 | 0.1026 | 0.0508 | 0.0518 |
| 100 | Sep-06 | 0.1037 | 0.0493 | 0.0544 |
| 101 | Oct-06 | 0.1014 | 0.0494 | 0.0520 |
| 102 | Nov-06 | 0.1018 | 0.0478 | 0.0540 |
| 103 | Dec-06 | 0.1021 | 0.0478 | 0.0543 |
| 104 | Jan-07 | 0.0998 | 0.0495 | 0.0503 |
| 105 | Feb-07 | 0.1003 | 0.0493 | 0.0510 |
| 106 | Mar-07 | 0.1004 | 0.0481 | 0.0523 |
| 107 | Apr-07 | 0.0994 | 0.0495 | 0.0499 |
| 108 | May-07 | 0.0955 | 0.0498 | 0.0457 |
| 109 | Jun-07 | 0.0957 | 0.0529 | 0.0428 |
| 110 | Jul-07 | 0.0995 | 0.0519 | 0.0476 |
| 111 | Aug-07 | 0.1008 | 0.0500 | 0.0508 |
| 112 | Sep-07 | 0.1002 | 0.0484 | 0.0518 |
| 113 | Oct-07 | 0.1068 | 0.0483 | 0.0585 |
| 114 | Nov-07 | 0.1071 | 0.0456 | 0.0615 |
| 115 | Dec-07 | 0.1072 | 0.0457 | 0.0615 |
| 116 | Jan-08 | 0.1100 | 0.0435 | 0.0665 |
| 117 | Feb-08 | 0.1127 | 0.0449 | 0.0678 |
| 118 | Mar-08 | 0.1134 | 0.0436 | 0.0698 |
| 119 | Apr-08 | 0.1155 | 0.0444 | 0.0711 |
| 120 | May-08 | 0.1056 | 0.0460 | 0.0596 |
| 121 | Jun-08 | 0.1049 | 0.0474 | 0.0575 |
| 122 | Jul-08 | 0.1073 | 0.0462 | 0.0611 |
| 123 | Aug-08 | 0.1108 | 0.0453 | 0.0655 |
| 124 | Sep-08 | 0.1114 | 0.0432 | 0.0682 |
| 125 | Oct-08 | 0.1193 | 0.0445 | 0.0748 |
| 126 | Nov-08 | 0.1200 | 0.0427 | 0.0773 |
| 127 | Dec-08 | 0.1139 | 0.0318 | 0.0821 |
| 128 | Jan-09 | 0.1108 | 0.0346 | 0.0762 |
| 129 | Feb-09 | 0.1131 | 0.0383 | 0.0748 |
| 130 | Mar-09 | 0.1172 | 0.0378 | 0.0794 |
| 131 | Apr-09 | 0.1123 | 0.0384 | 0.0739 |
| 132 | May-09 | 0.1196 | 0.0422 | 0.0774 |
| 133 | Jun-09 | 0.1180 | 0.0451 | 0.0729 |
| 134 | Jul-09 | 0.1119 | 0.0438 | 0.0681 |
| 135 | Aug-09 | 0.1086 | 0.0433 | 0.0653 |
| 136 | Sep-09 | 0.1085 | 0.0414 | 0.0671 |

| LINE | DATE | DCF | BOND YIELD | RISK PREMIUM |
|---|---|---|---|---|
| 137 | Oct-09 | 0.1125 | 0.0416 | 0.0709 |
| 138 | Nov-09 | 0.1127 | 0.0424 | 0.0703 |
| 139 | Dec-09 | 0.1103 | 0.0440 | 0.0663 |
| 140 | Jan-10 | 0.1174 | 0.0450 | 0.0724 |
| 141 | Feb-10 | 0.1141 | 0.0448 | 0.0693 |
| 142 | Mar-10 | 0.1049 | 0.0449 | 0.0600 |
| 143 | Apr-10 | 0.0912 | 0.0453 | 0.0459 |
| 144 | May-10 | 0.0947 | 0.0411 | 0.0536 |
| 145 | Jun-10 | 0.0931 | 0.0395 | 0.0536 |
| 146 | Jul-10 | 0.1028 | 0.0380 | 0.0648 |
| 147 | Aug-10 | 0.1017 | 0.0352 | 0.0665 |
| 148 | Sep-10 | 0.1013 | 0.0347 | 0.0666 |
| 149 | Oct-10 | 0.1027 | 0.0352 | 0.0675 |
| 150 | Nov-10 | 0.1019 | 0.0382 | 0.0637 |
| 151 | Dec-10 | 0.1007 | 0.0417 | 0.0590 |
| 152 | Jan-11 | 0.0998 | 0.0428 | 0.0570 |
| 153 | Feb-11 | 0.0984 | 0.0442 | 0.0542 |
| 154 | Mar-11 | 0.0994 | 0.0427 | 0.0567 |
| 155 | Apr-11 | 0.1034 | 0.0428 | 0.0606 |
| 156 | May-11 | 0.0998 | 0.0401 | 0.0597 |
| 157 | Jun-11 | 0.0998 | 0.0391 | 0.0607 |
| 158 | Jul-11 | 0.1038 | 0.0395 | 0.0643 |
| 159 | Aug-11 | 0.1156 | 0.0324 | 0.0832 |
| 160 | Sep-11 | 0.1133 | 0.0283 | 0.0850 |
| 161 | Oct-11 | 0.1128 | 0.0287 | 0.0841 |
| 162 | Nov-11 | 0.1099 | 0.0272 | 0.0827 |
| 163 | Dec-11 | 0.1072 | 0.0267 | 0.0805 |
| 164 | Jan-12 | 0.1058 | 0.0270 | 0.0788 |
| 165 | Feb-12 | 0.1060 | 0.0275 | 0.0785 |
| 166 | Mar-12 | 0.1060 | 0.0294 | 0.0766 |
| 167 | Apr-12 | 0.0970 | 0.0282 | 0.0688 |
| 168 | May-12 | 0.1048 | 0.0253 | 0.0795 |

Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 3 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

| | | |
|---|---|---|
| $d_0$ | = | Latest quarterly dividend per Value Line, Thomson Reuters |
| $P_0$ | = | Average of the monthly high and low stock prices for each month per Thomson Reuters |
| g | = | I/B/E/S forecast of future earnings growth for each month |
| k | = | Cost of equity using the quarterly version of the DCF model |

$$k = \left[ \frac{d_0 (1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

**EXHIBIT 12**
**CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY**
**USING SBBI® 6.6 PERCENT RISK PREMIUM**

| LINE | FACTOR | VALUE | SOURCE |
|---|---|---|---|
| 1 | Risk-free Rate | 2.95% | Long-term Canada Bond Forecast |
| 2 | Beta | 0.73 | Average Beta Proxy Companies |
| 3 | Risk Premium | 6.60% | Long-horizon SBBI risk premium |
| 4 | Beta x Risk Premium | 4.82% | |
| 5 | Flotation Cost Allowance | 0.50% | |
| 6 | Cost of Equity | 8.27% | |

Forecast bond yield from Consensus Economics, May 2012; SBBI® risk premium from I*bbotson® SBBI 2011® Valuation Edition Yearbook*, average Value Line beta for proxy utilities (see following page).

**EXHIBIT (CONTINUED)**
**VALUE LINE BETAS FOR PROXY UTILITIES**

| LINE | COMPANY | VALUE LINE BETA |
|---|---|---|
| 1 | AGL Resources | 0.75 |
| 2 | Alliant Energy | 0.75 |
| 3 | Amer. Elec. Power | 0.70 |
| 4 | Atmos Energy | 0.70 |
| 5 | CenterPoint Energy | 0.80 |
| 6 | CMS Energy Corp. | 0.75 |
| 7 | Consol. Edison | 0.60 |
| 8 | Dominion Resources | 0.70 |
| 9 | DTE Energy | 0.75 |
| 10 | Duke Energy | 0.65 |
| 11 | FirstEnergy Corp. | 0.80 |
| 12 | G't Plains Energy | 0.75 |
| 13 | Hawaiian Elec. | 0.70 |
| 14 | NextEra Energy | 0.75 |
| 15 | NiSource Inc. | 0.85 |
| 16 | Northeast Utilities | 0.70 |
| 17 | Northwest Nat. Gas | 0.60 |
| 18 | Pepco Holdings | 0.75 |
| 19 | Piedmont Natural Gas | 0.70 |
| 20 | Pinnacle West Capital | 0.70 |
| 21 | PNM Resources | 0.95 |
| 22 | Portland General | 0.75 |
| 23 | Public Serv. Enterprise | 0.80 |
| 24 | SCANA Corp. | 0.70 |
| 25 | Sempra Energy | 0.80 |
| 26 | Southern Co. | 0.55 |
| 27 | TECO Energy | 0.85 |
| 28 | Vectren Corp. | 0.75 |
| 29 | Westar Energy | 0.75 |
| 30 | WGL Holdings Inc. | 0.65 |
| 31 | Wisconsin Energy | 0.65 |
| 32 | Xcel Energy Inc. | 0.65 |
| 33 | Average | 0.73 |

**EXHIBIT 13**
**CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY**
**USING SBBI® 6.6 PERCENT RISK PREMIUM**

| LINE | FACTOR | VALUE | SOURCE |
|---|---|---|---|
| 1 | Risk-free Rate | 2.95% | Long-term Canada Bond Forecast |
| 2 | Beta | 0.92 | RP utility stocks/RP S&P500 |
| 3 | Risk Premium | 6.60% | Long-horizon SBBI risk premium |
| 4 | Beta x Risk Premium | 6.07% | |
| 5 | Flotation Cost Allowance | 0.50% | |
| 6 | Cost of Equity | 9.52% | |

Forecast bond yield from Consensus Economics, May 2012; SBBI® risk premium from I*bbotson® SBBI 2011® Valuation Edition Yearbook*, beta calculated as ratio of S&P Utilities stock risk premium compared to S&P 500 stock risk premium—see Exhibit 13.

**EXHIBIT 14**
**COMPARISON OF RISK PREMIA ON**
**S&P500 AND S&P UTILITIES 1937 – 2012**

| YEAR | S&P UTILITIES STOCK RETURN | SP500 STOCK RETURN | 10-YR. TREASURY BOND YIELD | UTILITIES RISK PREMIUM | MARKET RISK PREMIUM |
|---|---|---|---|---|---|
| 2011 | 0.1999 | 0.0325 | 0.0278 | 0.1721 | 0.0047 |
| 2010 | 0.0704 | 0.1618 | 0.0322 | 0.0382 | 0.1296 |
| 2009 | 0.1071 | 0.3291 | 0.0326 | 0.0745 | 0.2965 |
| 2008 | -0.2590 | -0.3519 | 0.0367 | -0.2957 | -0.3886 |
| 2007 | 0.1656 | -0.0127 | 0.0463 | 0.1193 | -0.0590 |
| 2006 | 0.2076 | 0.1320 | 0.0479 | 0.1597 | 0.0841 |
| 2005 | 0.1605 | 0.1001 | 0.0429 | 0.1176 | 0.0572 |
| 2004 | 0.2284 | 0.0594 | 0.0427 | 0.1857 | 0.0167 |
| 2003 | 0.2348 | 0.2822 | 0.0401 | 0.1947 | 0.2421 |
| 2002 | -0.1473 | -0.2005 | 0.0461 | -0.1934 | -0.2466 |
| 2001 | -0.1790 | -0.1347 | 0.0502 | -0.2292 | -0.1849 |
| 2000 | 0.3278 | -0.0513 | 0.0603 | 0.2675 | -0.1116 |
| 1999 | -0.0172 | 0.1546 | 0.0564 | -0.0736 | 0.0982 |
| 1998 | 0.1547 | 0.3125 | 0.0526 | 0.1021 | 0.2599 |
| 1997 | 0.1858 | 0.2768 | 0.0635 | 0.1223 | 0.2133 |
| 1996 | 0.0383 | 0.2702 | 0.0644 | -0.0261 | 0.2058 |
| 1995 | 0.3749 | 0.3493 | 0.0658 | 0.3091 | 0.2835 |
| 1994 | -0.0383 | 0.0105 | 0.0708 | -0.1091 | -0.0603 |
| 1993 | 0.1095 | 0.1156 | 0.0587 | 0.0508 | 0.0569 |
| 1992 | 0.1246 | 0.0750 | 0.0701 | 0.0545 | 0.0049 |
| 1991 | 0.1425 | 0.3165 | 0.0786 | 0.0639 | 0.2379 |
| 1990 | 0.0033 | -0.0085 | 0.0855 | -0.0822 | -0.0940 |
| 1989 | 0.3468 | 0.2276 | 0.0850 | 0.2618 | 0.1426 |
| 1988 | 0.1480 | 0.1761 | 0.0884 | 0.0596 | 0.0877 |
| 1987 | -0.0574 | -0.0213 | 0.0838 | -0.1412 | -0.1051 |
| 1986 | 0.3787 | 0.3095 | 0.0768 | 0.3019 | 0.2327 |
| 1985 | 0.3000 | 0.2583 | 0.1062 | 0.1938 | 0.1521 |
| 1984 | 0.1995 | 0.0741 | 0.1244 | 0.0751 | -0.0503 |
| 1983 | 0.2016 | 0.2012 | 0.1110 | 0.0906 | 0.0902 |
| 1982 | 0.3020 | 0.2896 | 0.1300 | 0.1720 | 0.1596 |
| 1981 | 0.0940 | -0.0700 | 0.1391 | -0.0451 | -0.2091 |
| 1980 | 0.1301 | 0.2534 | 0.1146 | 0.0155 | 0.1388 |
| 1979 | 0.0879 | 0.1652 | 0.0944 | -0.0065 | 0.0708 |
| 1978 | 0.0396 | 0.1580 | 0.0841 | -0.0445 | 0.0739 |
| 1977 | 0.0416 | -0.0906 | 0.0742 | -0.0326 | -0.1648 |
| 1976 | 0.2270 | 0.1096 | 0.0761 | 0.1509 | 0.0335 |
| 1975 | 0.3224 | 0.3856 | 0.0799 | 0.2425 | 0.3057 |
| 1974 | -0.1429 | -0.2086 | 0.0756 | -0.2185 | -0.2842 |
| 1973 | -0.1345 | -0.1614 | 0.0684 | -0.2029 | -0.2298 |
| 1972 | 0.0512 | 0.1758 | 0.0621 | -0.0109 | 0.1137 |
| 1971 | -0.0007 | 0.1381 | 0.0616 | -0.0623 | 0.0765 |

| YEAR | S&P UTILITIES STOCK RETURN | SP500 STOCK RETURN | 10-YR. TREASURY BOND YIELD | UTILITIES RISK PREMIUM | MARKET RISK PREMIUM |
|---|---|---|---|---|---|
| 1970 | 0.1945 | 0.0708 | 0.0735 | 0.1210 | -0.0027 |
| 1969 | -0.1438 | -0.0840 | 0.0667 | -0.2105 | -0.1507 |
| 1968 | 0.0528 | 0.1045 | 0.0565 | -0.0037 | 0.0480 |
| 1967 | 0.0022 | 0.1605 | 0.0507 | -0.0485 | 0.1098 |
| 1966 | -0.0172 | -0.0648 | 0.0492 | -0.0664 | -0.1140 |
| 1965 | 0.0134 | 0.1135 | 0.0428 | -0.0294 | 0.0707 |
| 1964 | 0.1611 | 0.1570 | 0.0419 | 0.1192 | 0.1151 |
| 1963 | 0.0947 | 0.2082 | 0.0400 | 0.0547 | 0.1682 |
| 1962 | 0.0425 | -0.0284 | 0.0395 | 0.0030 | -0.0679 |
| 1961 | 0.2247 | 0.1894 | 0.0388 | 0.1859 | 0.1506 |
| 1960 | 0.2252 | 0.0618 | 0.0412 | 0.1840 | 0.0206 |
| 1959 | 0.0500 | 0.0757 | 0.0433 | 0.0067 | 0.0324 |
| 1958 | 0.3688 | 0.3974 | 0.0332 | 0.3356 | 0.3642 |
| 1957 | 0.0790 | -0.0518 | 0.0365 | 0.0425 | -0.0883 |
| 1956 | 0.0716 | 0.0714 | 0.0318 | 0.0398 | 0.0396 |
| 1955 | 0.1016 | 0.2840 | 0.0282 | 0.0734 | 0.2558 |
| 1954 | 0.2237 | 0.4552 | 0.0240 | 0.1997 | 0.4312 |
| 1953 | 0.0962 | 0.0270 | 0.0281 | 0.0681 | -0.0011 |
| 1952 | 0.1536 | 0.1405 | 0.0248 | 0.1288 | 0.1157 |
| 1951 | 0.1710 | 0.2039 | 0.0241 | 0.1469 | 0.1798 |
| 1950 | 0.0460 | 0.3230 | 0.0205 | 0.0255 | 0.3025 |
| 1949 | 0.2783 | 0.1610 | 0.0193 | 0.2590 | 0.1417 |
| 1948 | 0.0541 | 0.0928 | 0.0215 | 0.0326 | 0.0713 |
| 1947 | -0.1041 | 0.0199 | 0.0185 | -0.1226 | 0.0014 |
| 1946 | -0.0700 | -0.1203 | 0.0174 | -0.0874 | -0.1377 |
| 1945 | 0.5789 | 0.3818 | 0.0173 | 0.5616 | 0.3645 |
| 1944 | 0.2065 | 0.1879 | 0.0209 | 0.1856 | 0.1670 |
| 1943 | 0.3745 | 0.2298 | 0.0207 | 0.3538 | 0.2091 |
| 1942 | 0.1736 | 0.2087 | 0.0211 | 0.1525 | 0.1876 |
| 1941 | -0.2838 | -0.0898 | 0.0199 | -0.3037 | -0.1097 |
| 1940 | -0.1652 | -0.0965 | 0.0220 | -0.1872 | -0.1185 |
| 1939 | 0.1126 | 0.0189 | 0.0235 | 0.0891 | -0.0046 |
| 1938 | 0.1954 | 0.1836 | 0.0255 | 0.1699 | 0.1581 |
| 1937 | -0.3693 | -0.3136 | 0.0269 | -0.3962 | -0.3405 |
| Risk Premium 1937—2012 | | | | 0.0521 | 0.0567 |
| RP Utilities/RP SP500 | | | | 0.92 | |

**EXHIBIT 15**
**COMPARISON OF RISK PREMIA ON**
**S&P TSX COMPOSITE, S&P TSX UTILITIES,**
**AND BMO CAPITAL MARKETS UTILITY GROUP**

| LINE | YEAR | TOTAL RETURN TSX COMPOSITE | S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN | BMO CAPITAL MARKETS UTILITY GROUP TOTAL RETURN | YIELD LONG-TERM CANADA BOND | RISK PREMIUM/TSX COMPOSITE | RISK PREMIUM SP/TSX UTILITIES | RISK PREMIUM BMO CM UTILITY GROUP |
|---|---|---|---|---|---|---|---|---|
| 1 | 1956 | 13.22 | 0.17 | | 3.63 | 9.59 | -3.45 | |
| 2 | 1957 | -20.58 | -3.43 | | 4.11 | -24.69 | -7.54 | |
| 3 | 1958 | 31.25 | 9.81 | | 4.15 | 27.10 | 5.66 | |
| 4 | 1959 | 4.59 | 0.21 | | 5.08 | -0.49 | -4.86 | |
| 5 | 1960 | 1.78 | 26.81 | | 5.19 | -3.40 | 21.62 | |
| 6 | 1961 | 32.75 | 19.17 | | 5.05 | 27.70 | 14.12 | |
| 7 | 1962 | -7.09 | -0.72 | | 5.11 | -12.21 | -5.83 | |
| 8 | 1963 | 15.60 | 6.19 | | 5.09 | 10.51 | 1.10 | |
| 9 | 1964 | 25.43 | 21.59 | | 5.18 | 20.25 | 16.41 | |
| 10 | 1965 | 6.68 | 4.23 | | 5.21 | 1.47 | -0.98 | |
| 11 | 1966 | -7.07 | -13.17 | | 5.69 | -12.76 | -18.86 | |
| 12 | 1967 | 18.09 | 5.07 | | 5.94 | 12.15 | -0.87 | |
| 13 | 1968 | 22.45 | 7.41 | | 6.75 | 15.70 | 0.66 | |
| 14 | 1969 | -0.81 | -8.62 | | 7.58 | -8.39 | -16.20 | |
| 15 | 1970 | -3.57 | 23.34 | | 7.91 | -11.48 | 15.43 | |
| 16 | 1971 | 8.01 | 4.29 | | 6.95 | 1.06 | -2.66 | |
| 17 | 1972 | 27.38 | -0.44 | | 7.23 | 20.15 | -7.68 | |
| 18 | 1973 | 0.27 | -4.14 | | 7.56 | -7.29 | -11.70 | |
| 19 | 1974 | -25.93 | 14.38 | | 8.90 | -34.83 | 5.48 | |
| 20 | 1975 | 18.48 | 5.75 | | 9.04 | 9.45 | -3.28 | |
| 21 | 1976 | 11.02 | 15.02 | | 9.18 | 1.85 | 5.84 | |
| 22 | 1977 | 10.71 | 19.00 | | 8.70 | 2.01 | 10.30 | |
| 23 | 1978 | 29.72 | 27.28 | | 9.27 | 20.45 | 18.01 | |
| 24 | 1979 | 44.77 | 12.61 | | 10.21 | 34.56 | 2.40 | |
| 25 | 1980 | 30.13 | 5.74 | | 12.48 | 17.65 | -6.74 | |
| 26 | 1981 | -10.25 | -0.55 | | 15.22 | -25.47 | -15.77 | |
| 27 | 1982 | 5.54 | 35.90 | | 14.26 | -8.71 | 21.65 | |
| 28 | 1983 | 35.49 | 40.97 | 25.84 | 11.79 | 23.70 | 29.17 | 14.05 |
| 29 | 1984 | -2.39 | 24.31 | 6.89 | 12.75 | -15.14 | 11.56 | -5.86 |
| 30 | 1985 | 25.07 | 10.04 | 20.09 | 11.04 | 14.02 | -1.00 | 9.04 |
| 31 | 1986 | 8.95 | 11.48 | -1.22 | 9.52 | -0.57 | 1.96 | -10.74 |
| 32 | 1987 | 5.88 | 1.07 | 11.98 | 9.95 | -4.07 | -8.88 | 2.03 |
| 33 | 1988 | 11.08 | 5.63 | 6.67 | 10.22 | 0.86 | -4.59 | -3.56 |
| 34 | 1989 | 21.37 | 22.07 | 23.80 | 9.92 | 11.45 | 12.15 | 13.88 |
| 35 | 1990 | -14.80 | 0.58 | 10.00 | 10.85 | -25.65 | -10.28 | -0.86 |
| 36 | 1991 | 12.02 | 27.02 | 12.92 | 9.76 | 2.25 | 17.25 | 3.16 |
| 37 | 1992 | -1.43 | -2.24 | 0.75 | 8.77 | -10.20 | -11.00 | -8.02 |
| 38 | 1993 | 32.55 | 23.52 | 33.00 | 7.85 | 24.70 | 15.67 | 25.15 |
| 39 | 1994 | -0.18 | -6.04 | -1.22 | 8.63 | -8.81 | -14.68 | -9.85 |
| 40 | 1995 | 14.53 | 18.44 | 15.13 | 8.28 | 6.25 | 10.16 | 6.85 |

| LINE | YEAR | TOTAL RETURN TSX COMPOSITE | S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN | BMO CAPITAL MARKETS UTILITY GROUP TOTAL RETURN | YIELD LONG-TERM CANADA BOND | RISK PREMIUM/TSX COMPOSITE | RISK PREMIUM SP/TSX UTILITIES | RISK PREMIUM BMO CM UTILITY GROUP |
|---|---|---|---|---|---|---|---|---|
| 41 | 1996 | 28.35 | 32.68 | 31.66 | 7.50 | 20.84 | 25.18 | 24.15 |
| 42 | 1997 | 14.98 | 37.33 | 50.16 | 6.42 | 8.55 | 30.91 | 43.74 |
| 43 | 1998 | -1.58 | 36.55 | 4.12 | 5.47 | -7.05 | 31.09 | -1.34 |
| 44 | 1999 | 31.71 | -27.14 | -24.11 | 5.69 | 26.02 | -32.83 | -29.80 |
| 45 | 2000 | 7.41 | 50.06 | 59.57 | 5.89 | 1.52 | 44.17 | 53.69 |
| 46 | 2001 | -12.57 | 10.83 | 16.05 | 5.78 | -18.35 | 5.05 | 10.27 |
| 47 | 2002 | -12.44 | 6.33 | 14.46 | 5.66 | -18.10 | 0.67 | 8.80 |
| 48 | 2003 | 26.72 | 24.94 | 28.74 | 5.28 | 21.45 | 19.66 | 23.46 |
| 49 | 2004 | 14.48 | 9.42 | 15.56 | 5.08 | 9.40 | 4.34 | 10.48 |
| 50 | 2005 | 24.13 | 38.29 | 33.36 | 4.39 | 19.74 | 33.90 | 28.97 |
| 51 | 2006 | 17.26 | 7.01 | 17.77 | 4.30 | 12.96 | 2.71 | 13.47 |
| 52 | 2007 | 9.83 | 11.89 | 4.90 | 4.34 | 5.50 | 7.55 | 0.57 |
| 53 | 2008 | -33.00 | -20.46 | -4.21 | 4.04 | -37.04 | -24.50 | -8.25 |
| 54 | 2009 | 35.06 | 19.00 | 20.24 | 3.89 | 31.17 | 15.11 | 16.35 |
| 55 | 2010 | 17.61 | 18.39 | 5.39 | 3.66 | 13.95 | 14.73 | 1.73 |
| 56 | 2011 | -8.71 | 6.47 | 25.89 | 3.21 | -11.92 | 3.26 | 22.68 |
| 57 | Average 1956 – 2011 | 10.53 | 11.99 | | 7.33 | 3.20 | 4.66 | |
| 58 | Average 1983 - 2011 | 10.60 | 15.12 | 16.01 | 7.24 | 3.36 | 7.88 | 8.77 |
| 59 | Std. Dev. 1956 – 2011 | 16.67 | 15.26 | | | | | |
| 60 | Std. Dev. 1983 - 2011 | 16.58 | 17.40 | 16.41 | | | | |

**EXHIBIT 16**
**ALLOWED RETURNS ON EQUITY**
**U.S. ELECTRIC UTILITIES**
**2010 – JUNE 2012[7]**

| LINE | COMPANY | STATE | DATE OF ORDER | ALLOWED ROE |
|---|---|---|---|---|
| 1 | Indiana Michigan Power Co. | Michigan | 11-Jan-10 | 10.2 |
| 2 | Interstate Power & Light Co. | Minnesota | 11-Jan-10 | 10.4 |
| 3 | Kansas City Power & Light | Missouri | 20-Jan-10 | 10.0 |
| 4 | Indiana Michigan Power Co. | Indiana | 21-Jan-10 | 10.5 |
| 5 | Portland General Electric Co. | Oregon | 26-Jan-10 | 10.0 |
| 6 | CenterPoint Energy Houston | Texas | 26-Jan-10 | 10.0 |
| 7 | South Carolina Electric & Gas | South Carolina | 27-Jan-10 | 11.0 |
| 8 | Duke Energy Carolinas LLC | South Carolina | 9-Feb-10 | 10.5 |
| 9 | Union Electric Co. | Missouri | 10-Feb-10 | 10.2 |
| 10 | PacifiCorp | Utah | 18-Feb-10 | 10.6 |
| 11 | PacifiCorp | Oregon | 24-Feb-10 | 10.1 |
| 12 | Virginia Electric & Power Co. | Virginia | 4-Mar-10 | 11.4 |
| 13 | Virginia Electric & Power Co. | Virginia | 11-Mar-10 | 12.3 |
| 14 | Virginia Electric & Power Co. | Virginia | 11-Mar-10 | 12.3 |
| 15 | Cheyenne Light Fuel Power Co. | Wyoming | 19-Mar-10 | 9.6 |
| 16 | Consolidated Edison Co. of NY | New York | 25-Mar-10 | 10.0 |
| 17 | Pacific Gas and Electric Co. | California | 1-Apr-10 | 11.4 |
| 18 | Madison Gas and Electric Co. | Wisconsin | 2-Apr-10 | 10.3 |
| 19 | Appalachian Power Co. | Virginia | 8-Apr-10 | 10.9 |
| 20 | PacifiCorp | Wyoming | 27-Apr-10 | 10.0 |
| 21 | Commonwealth Edison Co. | Illinois | 29-Apr-10 | 10.1 |
| 22 | Ameren Illinois | Illinois | 29-Apr-10 | 10.1 |
| 23 | Ameren Illinois | Illinois | 29-Apr-10 | 10.3 |
| 24 | Consumers Energy Co. | Michigan | 17-May-10 | 10.7 |
| 25 | Oklahoma Gas and Electric Co. | Arkansas | 28-May-10 | 10.0 |
| 26 | Union Electric Co. | Missouri | 28-May-10 | 10.8 |
| 27 | PacifiCorp | Utah | 15-Jun-10 | 10.6 |
| 28 | Central Hudson Gas & Electric | New York | 16-Jun-10 | 10.0 |
| 29 | Rockland Electric Company | New Jersey | 18-Jun-10 | 10.3 |
| 30 | Kansas City Power & Light | Kansas | 23-Jun-10 | 10.0 |
| 31 | Unitil Energy Systems Inc. | New Hampshire | 28-Jun-10 | 9.7 |
| 32 | ALLETE (Minnesota Power) | Minnesota | 1-Jul-10 | 10.4 |
| 33 | Northern States Power Co. - MN | South Dakota | 7-Jul-10 | 9.3 |
| 34 | Appalachian Power Co. | Virginia | 15-Jul-10 | 10.6 |
| 35 | Entergy Texas Inc. | Texas | 30-Jul-10 | 10.1 |
| 36 | Public Service Co. of CO | Colorado | 4-Aug-10 | 10.0 |
| 37 | Entergy Arkansas Inc. | Arkansas | 9-Aug-10 | 10.2 |
| 38 | Southern Indiana Gas & Elec Co | Indiana | 25-Aug-10 | 10.4 |
| 39 | Sierra Pacific Power Co. | California | 3-Sep-10 | 10.7 |
| 40 | Maui Electric Company Ltd | Hawaii | 14-Sep-10 | 10.0 |

[7] Data from Regulatory Research Associates, SNL Financial, July 5, 2012.

| LINE | COMPANY | STATE | DATE OF ORDER | ALLOWED ROE |
|---|---|---|---|---|
| 41 | Orange & Rockland Utlts Inc. | New York | 16-Sep-10 | 9.4 |
| 42 | Consolidated Edison Co. of NY | New York | 16-Sep-10 | 10.2 |
| 43 | Cleveland Elec Illuminating Co | Ohio | 16-Sep-10 | 10.5 |
| 44 | Avista Corp. | Idaho | 21-Sep-10 | 10.5 |
| 45 | South Carolina Electric & Gas | South Carolina | 30-Sep-10 | 10.7 |
| 46 | Hawaiian Electric Co. | Hawaii | 28-Oct-10 | 10.0 |
| 47 | ALLETE (Minnesota Power) | Minnesota | 2-Nov-10 | 10.7 |
| 48 | Northern IN Public Svc Co. | Indiana | 4-Nov-10 | 9.9 |
| 49 | Avista Corp. | Washington | 19-Nov-10 | 10.2 |
| 50 | Connecticut Light & Power Co. | Connecticut | 1-Dec-10 | 9.4 |
| 51 | Northern States Power Co. - MN | Minnesota | 6-Dec-10 | 10.9 |
| 52 | MDU Resources Group Inc. | North Dakota | 13-Dec-10 | 10.8 |
| 53 | PacifiCorp | Oregon | 14-Dec-10 | 10.1 |
| 54 | Texas-New Mexico Power Co. | Texas | 14-Dec-10 | 10.1 |
| 55 | Interstate Power & Light Co. | Iowa | 15-Dec-10 | 10.8 |
| 56 | Kentucky Utilities Co. | Virginia | 17-Dec-10 | 10.3 |
| 57 | Upper Peninsula Power Co. | Michigan | 21-Dec-10 | 10.9 |
| 58 | Hawaii Electric Light Co | Hawaii | 29-Dec-10 | 10.0 |
| 59 | Georgia Power Co. | Georgia | 30-Dec-10 | 11.2 |
| 60 | Public Service Co. of OK | Oklahoma | 5-Jan-11 | 10.5 |
| 61 | Upper Peninsula Power Co. | Michigan | 6-Jan-11 | 10.2 |
| 62 | Madison Gas and Electric Co. | Wisconsin | 12-Jan-11 | 10.4 |
| 63 | Appalachian Power Co. | West Virginia | 13-Jan-11 | 10.0 |
| 64 | Florida Power & Light Co. | Florida | 18-Jan-11 | 10.0 |
| 65 | Union Electric Co. | Missouri | 19-Jan-11 | 10.1 |
| 66 | Baltimore Gas and Electric Co. | Maryland | 31-Jan-11 | 9.9 |
| 67 | Hawaiian Electric Co. | Hawaii | 25-Feb-11 | 10.7 |
| 68 | Puget Sound Energy Inc. | Washington | 15-Mar-11 | 10.1 |
| 69 | Virginia Electric & Power Co. | Virginia | 22-Mar-11 | 11.9 |
| 70 | Virginia Electric & Power Co. | Virginia | 22-Mar-11 | 12.3 |
| 71 | Atlantic City Electric Co. | New Jersey | 26-Apr-11 | 10.3 |
| 72 | KCP&L Greater Missouri Op Co | Missouri | 4-May-11 | 10.0 |
| 73 | PacifiCorp | California | 13-May-11 | 10.6 |
| 74 | Consumers Energy Co. | Michigan | 26-May-11 | 10.7 |
| 75 | Northern States Power Co. - MN | North Dakota | 8-Jun-11 | 10.4 |
| 76 | Oklahoma Gas and Electric Co. | Arkansas | 17-Jun-11 | 10.3 |
| 77 | Delmarva Power & Light Co. | Delaware | 21-Jun-11 | 10.0 |
| 78 | Potomac Electric Power Co. | District of Columbia | 29-Jun-11 | 9.6 |
| 79 | Delmarva Power & Light Co. | Maryland | 8-Jul-11 | 10.0 |
| 80 | Massachusetts Electric Co. | Massachusetts | 1-Aug-11 | 10.4 |
| 81 | NorthWestern Corp. | Montana | 2-Aug-11 | 10.3 |
| 82 | Public Service Co. of NM | New Mexico | 8-Aug-11 | 10.5 |
| 83 | Oncor Electric Delivery Co. | Texas | 19-Aug-11 | 10.3 |
| 84 | Public Service Co. of CO | Colorado | 1-Sep-11 | 10.5 |
| 85 | Alaska Electric Light Power | Alaska | 2-Sep-11 | 12.9 |
| 86 | South Carolina Electric & Gas | South Carolina | 30-Sep-11 | 11.0 |
| 87 | Wisconsin Electric Power Co. | Wisconsin | 6-Oct-11 | 10.4 |

| LINE | COMPANY | STATE | DATE OF ORDER | ALLOWED ROE |
|---|---|---|---|---|
| 88 | Kentucky Utilities Co. | Virginia | 12-Oct-11 | 10.5 |
| 89 | Detroit Edison Co. | Michigan | 20-Oct-11 | 11.0 |
| 90 | Appalachian Power Co. | Virginia | 30-Nov-11 | 11.4 |
| 91 | UNS Electric Inc. | Arizona | 13-Dec-11 | 9.8 |
| 92 | Toledo Edison Co. | Ohio | 14-Dec-11 | 10.5 |
| 93 | Duke Energy Ohio Inc. | Ohio | 14-Dec-11 | 10.6 |
| 94 | Avista Corp. | Washington | 16-Dec-11 | 10.2 |
| 95 | Upper Peninsula Power Co. | Michigan | 20-Dec-11 | 10.3 |
| 96 | Northern States Power Co - WI | Wisconsin | 22-Dec-11 | 10.4 |
| 97 | Black Hills Colorado Electric | Colorado | 22-Dec-11 | 10.5 |
| 98 | Nevada Power Co. | Nevada | 23-Dec-11 | 10.8 |
| 99 | Idaho Power Co. | Idaho | 30-Dec-11 | 10.5 |
| 100 | Appalachian Power Co. | Virginia | 3-Jan-12 | 10.5 |
| 101 | PacifiCorp | Idaho | 10-Jan-12 | 9.9 |
| 102 | Ameren Illinois | Illinois | 10-Jan-12 | 9.9 |
| 103 | Duke Energy Carolinas LLC | South Carolina | 25-Jan-12 | 10.7 |
| 104 | Duke Energy Carolinas LLC | North Carolina | 27-Jan-12 | 10.7 |
| 105 | Public Service Co. of NM | New Mexico | 31-Jan-12 | 10.0 |
| 106 | Virginia Electric & Power Co. | Virginia | 2-Feb-12 | 12.3 |
| 107 | Indiana Michigan Power Co. | Michigan | 15-Feb-12 | 10.4 |
| 108 | Florida Power Corp. | Florida | 22-Feb-12 | 10.5 |
| 109 | Idaho Power Co. | Oregon | 23-Feb-12 | 10.2 |
| 110 | Otter Tail Power Co. | North Dakota | 29-Feb-12 | 10.8 |
| 111 | Virginia Electric & Power Co. | Virginia | 16-Mar-12 | 11.4 |
| 112 | Virginia Electric & Power Co. | Virginia | 20-Mar-12 | 11.4 |
| 113 | Duke Energy Carolinas LLC | North Carolina | 21-Mar-12 | 10.5 |
| 114 | Virginia Electric & Power Co. | Virginia | 23-Mar-12 | 12.4 |
| 115 | PacifiCorp | Washington | 30-Mar-12 | 9.8 |
| 116 | Hawaii Electric Light Co | Hawaii | 4-Apr-12 | 10.7 |
| 117 | Westar Energy Inc. | Kansas | 18-Apr-12 | 10.4 |
| 118 | Public Service Co. of NH | New Hampshire | 24-Apr-12 | 9.7 |
| 119 | Maui Electric Company Ltd | Hawaii | 2-May-12 | 10.7 |
| 120 | Arizona Public Service Co. | Arizona | 15-May-12 | 11.0 |
| 121 | Commonwealth Edison Co. | Illinois | 29-May-12 | 10.5 |
| 122 | Consumers Energy Co. | Michigan | 7-Jun-12 | 10.3 |
| 123 | Orange & Rockland Utlts Inc. | New York | 14-Jun-12 | 9.2 |
| 124 | Wisconsin Power and Light Co | Wisconsin | 15-Jun-12 | 10.4 |
| 125 | MDU Resources Group Inc. | Wyoming | 18-Jun-12 | 10.0 |
| 126 | Wisconsin Electric Power Co. | Michigan | 26-Jun-12 | 10.3 |
| 127 | Hawaiian Electric Co. | Hawaii | 29-Jun-12 | 10.0 |
| 183 | | **Average** | | **10.5** |

**EXHIBIT 17**
**ALLOWED RETURNS ON EQUITY**
**U.S. NATURAL GAS UTILITIES**
**2010 – JUNE 2011[8]**

| LINE | COMPANY | STATE | DATE | ALLOWED ROE |
|---|---|---|---|---|
| 1 | Atmos Energy Corp. | Tennessee | 5-Jan-10 | 10.3 |
| 2 | Northern Illinois Gas Co. | Illinois | 21-Jan-10 | 10.2 |
| 3 | Delmarva Power & Light Co. | Delaware | 2-Mar-10 | 10.0 |
| 4 | Florida Public Utilities Co. | Florida | 5-Mar-10 | 10.9 |
| 5 | Virginia Natural Gas Inc. | Virginia | 11-Mar-10 | 10.0 |
| 6 | North Shore Gas Co. | Illinois | 24-Mar-10 | 9.5 |
| 7 | Puget Sound Energy Inc. | Washington | 2-Apr-10 | 10.1 |
| 8 | Ameren Illinois | Illinois | 29-Apr-10 | 9.2 |
| 9 | Ameren Illinois | Illinois | 29-Apr-10 | 9.4 |
| 10 | Ameren Illinois | Illinois | 29-Apr-10 | 9.4 |
| 11 | Pivotal Utility Holdings Inc. | New Jersey | 12-May-10 | 10.3 |
| 12 | South Jersey Gas Co. | New Jersey | 12-May-10 | 10.3 |
| 13 | Piedmont Natural Gas Co. | Tennessee | 24-May-10 | 10.2 |
| 14 | Michigan Gas Utilities Corp | Michigan | 3-Jun-10 | 10.8 |
| 15 | Public Service Electric Gas | New Jersey | 7-Jun-10 | 10.3 |
| 16 | Central Hudson Gas & Electric | New York | 16-Jun-10 | 10.0 |
| 17 | CT Natural Gas Corp. | Connecticut | 30-Jun-10 | 9.3 |
| 18 | Washington Gas Light Co. | Maryland | 6-Aug-10 | 9.6 |
| 19 | SourceGas Distribution LLC | Nebraska | 17-Aug-10 | 9.6 |
| 20 | Missouri Gas Energy | Missouri | 18-Aug-10 | 10.0 |
| 21 | NY State Electric & Gas Corp. | New York | 16-Sep-10 | 10.0 |
| 22 | Rochester Gas & Electric Corp. | New York | 16-Sep-10 | 10.0 |
| 23 | UNS Gas Inc. | Arizona | 30-Sep-10 | 9.8 |
| 24 | Michigan Consolidated Gas Co. | Michigan | 14-Oct-10 | 11.0 |
| 25 | Duke Energy Kentucky Inc. | Kentucky | 21-Oct-10 | 10.4 |
| 26 | Colonial Gas Co. | Massachusetts | 2-Nov-10 | 9.8 |
| 27 | Columbia Gas of Massachusetts | Massachusetts | 2-Nov-10 | 10.0 |
| 28 | Atmos Energy Corp. | Georgia | 3-Nov-10 | 10.7 |
| 29 | Consumers Energy Co. | Michigan | 4-Nov-10 | 10.6 |
| 30 | Avista Corp. | Washington | 19-Nov-10 | 10.2 |
| 31 | Baltimore Gas and Electric Co. | Maryland | 6-Dec-10 | 9.6 |
| 32 | NorthWestern Corp. | Montana | 9-Dec-10 | 10.3 |
| 33 | Sierra Pacific Power Co. | Nevada | 20-Dec-10 | 10.1 |
| 34 | Southwest Gas Corp. | Nevada | 20-Dec-10 | 10.2 |
| 35 | Madison Gas and Electric Co. | Wisconsin | 12-Jan-11 | 10.3 |
| 36 | Wisconsin Public Service Corp. | Wisconsin | 13-Jan-11 | 10.3 |
| 37 | Niagara Mohawk Power Corp. | New York | 20-Jan-11 | 10.2 |
| 38 | CenterPoint Energy Resources | Texas | 3-Feb-11 | 10.1 |
| 39 | Black Hills Iowa Gas Utility | Iowa | 10-Feb-11 | 10.1 |

[8] Data from Regulatory Research Associates, SNL Financial, July 5, 2012.

| LINE | COMPANY | STATE | DATE | ALLOWED ROE |
|---|---|---|---|---|
| 40 | EnergyNorth Natural Gas Inc. | New Hampshire | 10-Mar-11 | 9.5 |
| 41 | Avista Corp. | Oregon | 10-Mar-11 | 10.1 |
| 42 | Hope Gas Inc | West Virginia | 30-Mar-11 | 9.5 |
| 43 | New England Gas Company | Massachusetts | 31-Mar-11 | 10.1 |
| 44 | CenterPoint Energy Resources | Texas | 18-Apr-11 | 10.5 |
| 45 | Pacific Gas and Electric Co. | California | 13-May-11 | 11.4 |
| 46 | MidAmerican Energy Co. | Illinois | 24-May-11 | 10.1 |
| 47 | Orange & Rockland Utlts Inc. | New York | 16-Jun-11 | 10.4 |
| 48 | Fitchburg Gas & Electric Light | Massachusetts | 1-Aug-11 | 9.2 |
| 49 | Minnesota Energy Resources | Minnesota | 12-Aug-11 | 9.7 |
| 50 | ENSTAR Natural Gas Co. | Alaska | 2-Sep-11 | 12.6 |
| 51 | Wisconsin Gas LLC | Wisconsin | 6-Oct-11 | 10.5 |
| 52 | Consumers Energy Co. | Michigan | 8-Nov-11 | 10.3 |
| 53 | Columbia Gas of Virginia Inc | Virginia | 28-Nov-11 | 10.1 |
| 54 | Washington Gas Light Co. | Virginia | 20-Dec-11 | 9.8 |
| 55 | Northern States Power Co - WI | Wisconsin | 22-Dec-11 | 10.4 |
| 56 | Ameren Illinois | Illinois | 5-Jan-12 | 9.1 |
| 57 | Peoples Gas Light & Coke Co. | Illinois | 10-Jan-12 | 10.2 |
| 58 | North Shore Gas Co. | Illinois | 10-Jan-12 | 10.3 |
| 59 | Atmos Energy Corp. | Texas | 23-Jan-12 | 10.4 |
| 60 | Peoples Gas System | Florida | 27-Feb-12 | 10.8 |
| 61 | Northern States Power Co. - MN | Minnesota | 29-Mar-12 | 10.1 |
| 62 | UNS Gas Inc. | Arizona | 24-Apr-12 | 9.5 |
| 63 | Public Service Co. of CO | Colorado | 26-Apr-12 | 10.1 |
| 64 | Puget Sound Energy Inc. | Washington | 7-May-12 | 9.8 |
| 65 | SourceGas Distribution LLC | Nebraska | 22-May-12 | 9.6 |
| 66 | Minnesota Energy Resources | Minnesota | 24-May-12 | 10.2 |
| 67 | Consumers Energy Co. | Michigan | 7-Jun-12 | 10.5 |
| 68 | Wisconsin Power and Light Co | Wisconsin | 15-Jun-12 | 10.4 |
| 69 | Cheyenne Light Fuel Power Co. | Wyoming | 18-Jun-12 | 9.6 |
| 70 | Washington Gas Light Co. | Virginia | 2-Jul-12 | 10.0 |
| 71 | | **Average** | | **10.1** |

**EXHIBIT 18**
**ALLOWED EQUITY RATIOS**
**U.S. ELECTRIC UTILITIES**
**2009 – 2011[9]**

| LINE | COMPANY | STATE | DATE OF ORDER | COMMON EQUITY /TOTAL CAP (%) |
|---|---|---|---|---|
| 1 | Entergy Arkansas Inc. | Arkansas | 9-Aug-10 | 29.3 |
| 2 | Oklahoma Gas and Electric Co. | Arkansas | 28-May-10 | 34.9 |
| 3 | Oklahoma Gas and Electric Co. | Arkansas | 17-Jun-11 | 36.0 |
| 4 | Detroit Edison Co. | Michigan | 20-Oct-11 | 39.5 |
| 5 | Oncor Electric Delivery Co. | Texas | 19-Aug-11 | 40.0 |
| 6 | Consumers Energy Co. | Michigan | 17-May-10 | 40.5 |
| 7 | Appalachian Power Co. | Virginia | 15-Jul-10 | 41.5 |
| 8 | Appalachian Power Co. | Virginia | 3-Jan-12 | 41.5 |
| 9 | Consumers Energy Co. | Michigan | 26-May-11 | 41.6 |
| 1 | Indiana Michigan Power Co. | Michigan | 11-Jan-10 | 42.1 |
| 2 | Consumers Energy Co. | Michigan | 7-Jun-12 | 42.1 |
| 3 | Appalachian Power Co. | West Virginia | 13-Jan-11 | 42.2 |
| 4 | Appalachian Power Co. | Virginia | 8-Apr-10 | 42.7 |
| 5 | Southern Indiana Gas & Elec Co | Indiana | 25-Aug-10 | 43.5 |
| 6 | Ameren Illinois | Illinois | 29-Apr-10 | 43.6 |
| 7 | Ameren Illinois | Illinois | 10-Jan-12 | 43.6 |
| 8 | Sierra Pacific Power Co. | California | 3-Sep-10 | 43.7 |
| 9 | Public Service Co. of OK | Oklahoma | 5-Jan-11 | 44.1 |
| 10 | Indiana Michigan Power Co. | Michigan | 15-Feb-12 | 44.1 |
| 11 | Nevada Power Co. | Nevada | 23-Dec-11 | 44.2 |
| 12 | CenterPoint Energy Houston | Texas | 26-Jan-10 | 45.0 |
| 13 | Texas-New Mexico Power Co. | Texas | 14-Dec-10 | 45.0 |
| 14 | Unitil Energy Systems Inc. | New Hampshire | 28-Jun-10 | 45.5 |
| 15 | Upper Peninsula Power Co. | Michigan | 6-Jan-11 | 45.7 |
| 16 | UNS Electric Inc. | Arizona | 13-Dec-11 | 45.8 |
| 17 | Indiana Michigan Power Co. | Indiana | 21-Jan-10 | 45.8 |
| 18 | Puget Sound Energy Inc. | Washington | 15-Mar-11 | 46.0 |
| 19 | Commonwealth Edison Co. | Illinois | 29-Apr-10 | 46.2 |
| 20 | Potomac Electric Power Co. | District of Columbia | 29-Jun-11 | 46.2 |
| 21 | Kansas City Power & Light | Missouri | 20-Jan-10 | 46.3 |
| 22 | Avista Corp. | Washington | 19-Nov-10 | 46.5 |
| 23 | Avista Corp. | Washington | 16-Dec-11 | 46.5 |
| 24 | KCP&L Greater Missouri Op Co | Missouri | 4-May-11 | 46.6 |
| 25 | Florida Power Corp. | Florida | 22-Feb-12 | 46.7 |
| 26 | Central Hudson Gas & Electric | New York | 16-Jun-10 | 47.0 |
| 27 | Florida Power & Light Co. | Florida | 18-Jan-11 | 47.0 |
| 28 | Commonwealth Edison Co. | Illinois | 29-May-12 | 47.3 |

[9] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

| LINE | COMPANY | STATE | DATE OF ORDER | COMMON EQUITY /TOTAL CAP (%) |
|---|---|---|---|---|
| 29 | Virginia Electric & Power Co. | Virginia | 11-Mar-10 | 47.4 |
| 30 | Delmarva Power & Light Co. | Delaware | 21-Jun-11 | 47.5 |
| 31 | Wisconsin Electric Power Co. | Michigan | 26-Jun-12 | 47.6 |
| 32 | Virginia Electric & Power Co. | Virginia | 11-Mar-10 | 47.7 |
| 33 | Interstate Power & Light Co. | Minnesota | 11-Jan-10 | 47.7 |
| 34 | Consolidated Edison Co. of NY | New York | 25-Mar-10 | 48.0 |
| 35 | Orange & Rockland Utlts Inc. | New York | 16-Sep-10 | 48.0 |
| 36 | Consolidated Edison Co. of NY | New York | 16-Sep-10 | 48.0 |
| 37 | NorthWestern Corp. | Montana | 2-Aug-11 | 48.0 |
| 38 | Orange & Rockland Utlts Inc. | New York | 14-Jun-12 | 48.0 |
| 39 | Ameren Illinois | Illinois | 29-Apr-10 | 48.7 |
| 40 | Cleveland Elec Illuminating Co | Ohio | 16-Sep-10 | 49.0 |
| 41 | Toledo Edison Co. | Ohio | 14-Dec-11 | 49.0 |
| 42 | Atlantic City Electric Co. | New Jersey | 26-Apr-11 | 49.1 |
| 43 | PacifiCorp | Washington | 30-Mar-12 | 49.1 |
| 44 | Connecticut Light & Power Co. | Connecticut | 1-Dec-10 | 49.2 |
| 45 | Idaho Power Co. | Idaho | 30-Dec-11 | 49.3 |
| 46 | Virginia Electric & Power Co. | Virginia | 22-Mar-11 | 49.4 |
| 47 | Virginia Electric & Power Co. | Virginia | 2-Feb-12 | 49.4 |
| 48 | Interstate Power & Light Co. | Iowa | 15-Dec-10 | 49.5 |
| 49 | Upper Peninsula Power Co. | Michigan | 21-Dec-10 | 49.5 |
| 50 | Kansas City Power & Light | Kansas | 23-Jun-10 | 49.7 |
| 51 | MDU Resources Group Inc. | Wyoming | 18-Jun-12 | 49.8 |
| 52 | Idaho Power Co. | Oregon | 23-Feb-12 | 49.8 |
| 53 | Rockland Electric Company | New Jersey | 18-Jun-10 | 49.9 |
| 54 | Delmarva Power & Light Co. | Maryland | 8-Jul-11 | 49.9 |
| 55 | Northern IN Public Svc Co. | Indiana | 4-Nov-10 | 50.0 |
| 56 | Massachusetts Electric Co. | Massachusetts | 1-Aug-11 | 50.0 |
| 57 | Portland General Electric Co. | Oregon | 26-Jan-10 | 50.0 |
| 58 | Avista Corp. | Idaho | 21-Sep-10 | 50.0 |
| 59 | Westar Energy Inc. | Kansas | 18-Apr-12 | 50.1 |
| 60 | Wisconsin Power and Light Co | Wisconsin | 15-Jun-12 | 50.4 |
| 61 | Upper Peninsula Power Co. | Michigan | 20-Dec-11 | 50.4 |
| 62 | Public Service Co. of NM | New Mexico | 8-Aug-11 | 50.5 |
| 63 | PacifiCorp | Utah | 18-Feb-10 | 51.0 |
| 64 | PacifiCorp | Oregon | 24-Feb-10 | 51.0 |
| 65 | PacifiCorp | Utah | 15-Jun-10 | 51.0 |
| 66 | PacifiCorp | Oregon | 14-Dec-10 | 51.0 |
| 67 | Hawaii Electric Light Co | Hawaii | 4-Apr-12 | 51.2 |
| 68 | Union Electric Co. | Missouri | 19-Jan-11 | 51.3 |
| 69 | Public Service Co. of NM | New Mexico | 31-Jan-12 | 51.3 |
| 70 | Duke Energy Ohio Inc. | Ohio | 14-Dec-11 | 51.6 |
| 71 | Baltimore Gas and Electric Co. | Maryland | 31-Jan-11 | 51.9 |
| 72 | Pacific Gas and Electric Co. | California | 1-Apr-10 | 52.0 |

| LINE | COMPANY | STATE | DATE OF ORDER | COMMON EQUITY /TOTAL CAP (%) |
|---|---|---|---|---|
| 73 | Black Hills Colorado Electric | Colorado | 22-Dec-11 | 52.0 |
| 74 | Union Electric Co. | Missouri | 28-May-10 | 52.0 |
| 75 | PacifiCorp | Idaho | 10-Jan-12 | 52.1 |
| 76 | PacifiCorp | California | 13-May-11 | 52.2 |
| 77 | Union Electric Co. | Missouri | 10-Feb-10 | 52.2 |
| 78 | PacifiCorp | Wyoming | 27-Apr-10 | 52.3 |
| 79 | Northern States Power Co - WI | Wisconsin | 22-Dec-11 | 52.3 |
| 80 | Public Service Co. of NH | New Hampshire | 24-Apr-12 | 52.4 |
| 81 | Northern States Power Co. - MN | Minnesota | 6-Dec-10 | 52.5 |
| 82 | Duke Energy Carolinas LLC | North Carolina | 27-Jan-12 | 52.5 |
| 83 | South Carolina Electric & Gas | South Carolina | 30-Sep-10 | 53.0 |
| 84 | Duke Energy Carolinas LLC | South Carolina | 9-Feb-10 | 53.0 |
| 85 | Duke Energy Carolinas LLC | South Carolina | 25-Jan-12 | 53.0 |
| 86 | Duke Energy Carolinas LLC | North Carolina | 21-Mar-12 | 53.0 |
| 87 | Wisconsin Electric Power Co. | Wisconsin | 6-Oct-11 | 53.0 |
| 88 | Northern States Power Co. - MN | South Dakota | 7-Jul-10 | 53.0 |
| 89 | Virginia Electric & Power Co. | Virginia | 4-Mar-10 | 53.3 |
| 90 | Virginia Electric & Power Co. | Virginia | 16-Mar-12 | 53.3 |
| 91 | Virginia Electric & Power Co. | Virginia | 20-Mar-12 | 53.3 |
| 92 | Virginia Electric & Power Co. | Virginia | 23-Mar-12 | 53.3 |
| 93 | Otter Tail Power Co. | North Dakota | 29-Feb-12 | 53.3 |
| 94 | MDU Resources Group Inc. | North Dakota | 13-Dec-10 | 53.3 |
| 95 | Kentucky Utilities Co. | Virginia | 17-Dec-10 | 53.4 |
| 96 | South Carolina Electric & Gas | South Carolina | 30-Sep-11 | 53.5 |
| 97 | Kentucky Utilities Co. | Virginia | 12-Oct-11 | 53.6 |
| 98 | Arizona Public Service Co. | Arizona | 15-May-12 | 53.8 |
| 99 | Alaska Electric Light Power | Alaska | 2-Sep-11 | 53.8 |
| 100 | Cheyenne Light Fuel Power Co. | Wyoming | 19-Mar-10 | 54.0 |
| 101 | ALLETE (Minnesota Power) | Minnesota | 1-Jul-10 | 54.3 |
| 102 | South Carolina Electric & Gas | South Carolina | 27-Jan-10 | 54.7 |
| 103 | ALLETE (Minnesota Power) | Minnesota | 2-Nov-10 | 54.8 |
| 104 | Maui Electric Company Ltd | Hawaii | 2-May-12 | 54.9 |
| 105 | Hawaiian Electric Co. | Hawaii | 25-Feb-11 | 55.1 |
| 106 | Madison Gas and Electric Co. | Wisconsin | 12-Jan-11 | 55.3 |
| 107 | Hawaiian Electric Co. | Hawaii | 29-Jun-12 | 55.8 |
| 108 | Hawaii Electric Light Co | Hawaii | 29-Dec-10 | 55.9 |
| 109 | Public Service Co. of CO | Colorado | 4-Aug-10 | 56.0 |
| 110 | Hawaiian Electric Co. | Hawaii | 28-Oct-10 | 56.3 |
| 111 | Maui Electric Company Ltd | Hawaii | 14-Sep-10 | 56.9 |
| 112 | Madison Gas and Electric Co. | Wisconsin | 2-Apr-10 | 58.1 |
| 113 | Public Service Co. of CO | Colorado | 1-Sep-11 | 58.6 |
| 114 | | **Average** | | **49.2** |

**EXHIBIT 19**
**ALLOWED EQUITY RATIOS**
**U.S. NATURAL GAS UTILITIES**
**2009 – 2011[10]**

| LINE | COMPANY | STATE | DATE | COMMON EQUITY /TOTAL CAP (%) |
|---|---|---|---|---|
| 1 | Atmos Energy Corp. | Tennessee | 5-Jan-10 | 48.1 |
| 2 | Northern Illinois Gas Co. | Illinois | 21-Jan-10 | 51.1 |
| 3 | Florida Public Utilities Co. | Florida | 5-Mar-10 | 42.2 |
| 4 | Virginia Natural Gas Inc. | Virginia | 11-Mar-10 | 45.4 |
| 5 | North Shore Gas Co. | Illinois | 24-Mar-10 | 50.0 |
| 6 | Puget Sound Energy Inc. | Washington | 2-Apr-10 | 46.0 |
| 7 | Ameren Illinois | Illinois | 29-Apr-10 | 43.6 |
| 8 | Ameren Illinois | Illinois | 29-Apr-10 | 43.6 |
| 9 | Ameren Illinois | Illinois | 29-Apr-10 | 48.7 |
| 10 | Pivotal Utility Holdings Inc. | New Jersey | 12-May-10 | 47.9 |
| 11 | South Jersey Gas Co. | New Jersey | 12-May-10 | 51.2 |
| 12 | Piedmont Natural Gas Co. | Tennessee | 24-May-10 | 52.7 |
| 13 | Michigan Gas Utilities Corp | Michigan | 3-Jun-10 | 47.3 |
| 14 | Public Service Electric Gas | New Jersey | 7-Jun-10 | 51.2 |
| 15 | Central Hudson Gas & Electric | New York | 16-Jun-10 | 48.0 |
| 16 | CT Natural Gas Corp. | Connecticut | 30-Jun-10 | 52.5 |
| 17 | Washington Gas Light Co. | Maryland | 6-Aug-10 | 57.9 |
| 18 | SourceGas Distribution LLC | Nebraska | 17-Aug-10 | 51.2 |
| 19 | Missouri Gas Energy | Missouri | 18-Aug-10 | 38.7 |
| 20 | NY State Electric & Gas Corp. | New York | 16-Sep-10 | 48.0 |
| 21 | Rochester Gas & Electric Corp. | New York | 16-Sep-10 | 48.0 |
| 22 | UNS Gas Inc. | Arizona | 30-Sep-10 | 50.8 |
| 23 | Michigan Consolidated Gas Co. | Michigan | 14-Oct-10 | 38.8 |
| 24 | Duke Energy Kentucky Inc. | Kentucky | 21-Oct-10 | 49.9 |
| 25 | Colonial Gas Co. | Massachusetts | 2-Nov-10 | 50.0 |
| 26 | Columbia Gas of Massachusetts | Massachusetts | 2-Nov-10 | 53.6 |
| 27 | Atmos Energy Corp. | Georgia | 3-Nov-10 | 47.7 |
| 28 | Consumers Energy Co. | Michigan | 4-Nov-10 | 40.8 |
| 29 | Avista Corp. | Washington | 19-Nov-10 | 46.5 |
| 30 | Baltimore Gas and Electric Co. | Maryland | 6-Dec-10 | 51.9 |
| 31 | NorthWestern Corp. | Montana | 9-Dec-10 | 48.0 |
| 32 | Sierra Pacific Power Co. | Nevada | 20-Dec-10 | 44.1 |
| 33 | Southwest Gas Corp. | Nevada | 20-Dec-10 | 47.1 |
| 34 | Madison Gas and Electric Co. | Wisconsin | 12-Jan-11 | 58.1 |
| 35 | Wisconsin Public Service Corp. | Wisconsin | 13-Jan-11 | 51.7 |
| 36 | Niagara Mohawk Power Corp. | New York | 20-Jan-11 | 43.7 |
| 37 | CenterPoint Energy Resources | Texas | 3-Feb-11 | 55.4 |

[10] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

| LINE | COMPANY | STATE | DATE | COMMON EQUITY /TOTAL CAP (%) |
|---|---|---|---|---|
| 38 | Black Hills Iowa Gas Utility | Iowa | 10-Feb-11 | 51.4 |
| 39 | EnergyNorth Natural Gas Inc. | New Hampshire | 10-Mar-11 | 50.0 |
| 40 | Avista Corp. | Oregon | 10-Mar-11 | 50.0 |
| 41 | Hope Gas Inc | West Virginia | 30-Mar-11 | 42.3 |
| 42 | New England Gas Company | Massachusetts | 31-Mar-11 | 34.2 |
| 43 | CenterPoint Energy Resources | Texas | 18-Apr-11 | 55.6 |
| 44 | Pacific Gas and Electric Co. | California | 13-May-11 | 52.0 |
| 45 | MidAmerican Energy Co. | Illinois | 24-May-11 | 47.1 |
| 46 | Orange & Rockland Utlts Inc. | New York | 16-Jun-11 | 48.0 |
| 47 | Fitchburg Gas & Electric Light | Massachusetts | 1-Aug-11 | 42.9 |
| 48 | ENSTAR Natural Gas Co. | Alaska | 2-Sep-11 | 51.4 |
| 49 | Wisconsin Gas LLC | Wisconsin | 6-Oct-11 | 46.6 |
| 50 | Columbia Gas of Virginia Inc | Virginia | 28-Nov-11 | 42.7 |
| 51 | Washington Gas Light Co. | Virginia | 20-Dec-11 | 59.6 |
| 52 | Northern IN Public Svc Co. | Indiana | 21-Dec-11 | 46.3 |
| 53 | Northern States Power Co - WI | Wisconsin | 22-Dec-11 | 52.6 |
| 54 | Ameren Illinois | Illinois | 5-Jan-12 | 53.3 |
| 55 | Peoples Gas Light & Coke Co. | Illinois | 10-Jan-12 | 56.0 |
| 56 | North Shore Gas Co. | Illinois | 10-Jan-12 | 56.0 |
| 57 | Atmos Energy Corp. | Texas | 23-Jan-12 | 48.9 |
| 58 | Peoples Gas System | Florida | 27-Feb-12 | 48.5 |
| 59 | Northern States Power Co. - MN | Minnesota | 29-Mar-12 | 52.5 |
| 60 | UNS Gas Inc. | Arizona | 24-Apr-12 | 49.9 |
| 61 | Public Service Co. of CO | Colorado | 26-Apr-12 | 56.0 |
| 62 | Puget Sound Energy Inc. | Washington | 7-May-12 | 48.0 |
| 63 | SourceGas Distribution LLC | Nebraska | 22-May-12 | 50.0 |
| 64 | Minnesota Energy Resources | Minnesota | 24-May-12 | 48.8 |
| 65 | Wisconsin Power and Light Co | Wisconsin | 15-Jun-12 | 49.3 |
| 66 | Cheyenne Light Fuel Power Co. | Wyoming | 18-Jun-12 | 54.0 |
| 67 | Washington Gas Light Co. | Virginia | 2-Jul-12 | 55.7 |
| 68 | | **Average** | | **49.1** |

**EXHIBIT 20**
**MARKET VALUE EQUITY RATIOS FOR COMPREHENSIVE GROUP OF U.S. UTILITIES AT MAY 2012**

| LINE | COMPANY | LONG-TERM DEBT | PREFERRED EQUITY | MARKET CAP $ (MIL) | % LONG-TERM DEBT | % PREFERRED | % MARKET EQUITY |
|---|---|---|---|---|---|---|---|
| 1 | AGL Resources | 3,561 | 0 | 4,333 | 45.1% | 0.0% | 54.9% |
| 2 | Alliant Energy | 2,703 | 205 | 4,817 | 35.0% | 2.7% | 62.4% |
| 3 | Amer. Elec. Power | 15,083 | 0 | 18,577 | 44.8% | 0.0% | 55.2% |
| 4 | Atmos Energy | 2,206 | 0 | 2,975 | 42.6% | 0.0% | 57.4% |
| 5 | CenterPoint Energy | 8,641 | 0 | 8,533 | 50.3% | 0.0% | 49.7% |
| 6 | CMS Energy Corp. | 6,207 | 44 | 6,035 | 50.5% | 0.4% | 49.1% |
| 7 | Consol. Edison | 10,145 | 213 | 17,658 | 36.2% | 0.8% | 63.0% |
| 8 | Dominion Resources | 17,394 | 257 | 29,506 | 36.9% | 0.5% | 62.6% |
| 9 | DTE Energy | 7,187 | 0 | 9,584 | 42.9% | 0.0% | 57.1% |
| 10 | Duke Energy | 18,679 | 0 | 29,907 | 38.4% | 0.0% | 61.6% |
| 11 | FirstEnergy Corp. | 15,716 | 0 | 19,451 | 44.7% | 0.0% | 55.3% |
| 12 | G't Plains Energy | 2,742 | 39 | 2,717 | 49.9% | 0.7% | 49.4% |
| 13 | Hawaiian Elec. | 1,275 | 34 | 2,653 | 32.2% | 0.9% | 67.0% |
| 14 | NextEra Energy | 20,810 | 0 | 26,939 | 43.6% | 0.0% | 56.4% |
| 15 | NiSource Inc. | 5,936 | 0 | 7,023 | 45.8% | 0.0% | 54.2% |
| 16 | Northeast Utilities | 4,727 | 116 | 11,421 | 29.1% | 0.7% | 70.2% |
| 17 | Northwest Nat. Gas | 592 | 0 | 1,226 | 32.6% | 0.0% | 67.4% |
| 18 | Pepco Holdings | 4,062 | 0 | 4,392 | 48.0% | 0.0% | 52.0% |
| 19 | Piedmont Natural Gas | 675 | 0 | 2,144 | 23.9% | 0.0% | 76.1% |
| 20 | Pinnacle West Capital | 3,019 | 0 | 5,411 | 35.8% | 0.0% | 64.2% |
| 21 | PNM Resources | 1,672 | 12 | 1,451 | 53.3% | 0.4% | 46.3% |
| 22 | Portland General | 1,635 | 0 | 1,886 | 46.4% | 0.0% | 53.6% |
| 23 | Public Serv. Enterprise | 7,461 | 0 | 15,784 | 32.1% | 0.0% | 67.9% |
| 24 | SCANA Corp. | 4,622 | 0 | 6,098 | 43.1% | 0.0% | 56.9% |
| 25 | Sempra Energy | 10,078 | 99 | 15,440 | 39.3% | 0.4% | 60.3% |
| 26 | Southern Co. | 18,647 | 1,082 | 39,916 | 31.3% | 1.8% | 66.9% |
| 27 | TECO Energy | 2,687 | 0 | 3,712 | 42.0% | 0.0% | 58.0% |
| 28 | Vectren Corp. | 1,560 | 0 | 2,383 | 39.6% | 0.0% | 60.4% |
| 29 | Westar Energy | 2,740 | 21 | 3,614 | 43.0% | 0.3% | 56.7% |
| 30 | WGL Holdings Inc. | 587 | 28 | 2,002 | 22.4% | 1.1% | 76.5% |
| 31 | Wisconsin Energy | 4,614 | 30 | 8,709 | 34.6% | 0.2% | 65.2% |
| 32 | Xcel Energy Inc. | 8,849 | 0 | 13,614 | 39.4% | 0.0% | 60.6% |
| 33 | Average | | | 0 | 39.8% | 0.3% | 59.8% |

**EXHIBIT 21**
**MARKET VALUE EQUITY RATIOS FOR SMALLER GROUP OF U.S. UTILITIES WITH MOSTLY REGULATED ASSETS AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB**

| LINE | COMPANY | LONG-TERM DEBT | PREFERRED EQUITY | MARKET CAP $ (MIL) | % LONG-TERM DEBT | % PREFERRED | % MARKET EQUITY |
|---|---|---|---|---|---|---|---|
| 1 | AGL Resources | 3,561 | 0 | 4,333 | 45.1% | 0.0% | 54.9% |
| 2 | Alliant Energy | 2,703 | 205 | 4,817 | 35.0% | 2.7% | 62.4% |
| 3 | Amer. Elec. Power | 15,083 | 0 | 18,577 | 44.8% | 0.0% | 55.2% |
| 4 | Atmos Energy | 2,206 | 0 | 2,975 | 42.6% | 0.0% | 57.4% |
| 5 | Consol. Edison | 10,145 | 213 | 17,658 | 36.2% | 0.8% | 63.0% |
| 6 | DTE Energy | 7,187 | 0 | 9,584 | 42.9% | 0.0% | 57.1% |
| 7 | G't Plains Energy | 2,742 | 39 | 2,717 | 49.9% | 0.7% | 49.4% |
| 8 | Northeast Utilities | 4,727 | 116 | 11,421 | 29.1% | 0.7% | 70.2% |
| 9 | Northwest Nat. Gas | 592 | 0 | 1,226 | 32.6% | 0.0% | 67.4% |
| 10 | Piedmont Natural Gas | 675 | 0 | 2,144 | 23.9% | 0.0% | 76.1% |
| 11 | Pinnacle West Capital | 3,019 | 0 | 5,411 | 35.8% | 0.0% | 64.2% |
| 12 | Portland General | 1,635 | 0 | 1,886 | 46.4% | 0.0% | 53.6% |
| 13 | Southern Co. | 18,647 | 1,082 | 39,916 | 31.3% | 1.8% | 66.9% |
| 14 | TECO Energy | 2,687 | 0 | 3,712 | 42.0% | 0.0% | 58.0% |
| 15 | Vectren Corp. | 1,560 | 0 | 2,383 | 39.6% | 0.0% | 60.4% |
| 16 | Westar Energy | 2,740 | 21 | 3,614 | 43.0% | 0.3% | 56.7% |
| 17 | WGL Holdings Inc. | 587 | 28 | 2,002 | 22.4% | 1.1% | 76.5% |
| 18 | Wisconsin Energy | 4,614 | 30 | 8,709 | 34.6% | 0.2% | 65.2% |
| 19 | Xcel Energy Inc. | 8,849 | 0 | 13,614 | 39.4% | 0.0% | 60.6% |
| 20 | Average | | | | 37.7% | 0.4% | 61.9% |

Data are from The Value Line Investment Analyzer, May 2012.

**EXHIBIT 22**
**APPENDIX 1**
**QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.**

**JAMES H. VANDER WEIDE, Ph.D.**
3606 Stoneybrook Drive
Durham, NC 27705
Tel. 919.383.6659
jim.vanderweide@duke.edu

James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance*; a chapter titled "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory" for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques;* and research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management. His articles have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business,* and *Computers and Operations Research*.

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the telecommunications, electric, gas, insurance, and water industries for more than twenty-five years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Energy Board (Canada), the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of forty-three states, the District of Columbia, four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in telecommunications-related proceedings before the United States District Court for the District of New Hampshire, United States District Court for the Northern District of California, United States District Court for the Northern District of Illinois, Montana Second Judicial District Court Silver Bow County, the United States Bankruptcy Court for the Southern District of West Virginia, and United States District Court for the Eastern District of Michigan. He also testified as an expert before the United States Tax Court, United States District Court for the Eastern District of North Carolina; United States District Court for the District of Nebraska, and Superior Court of North Carolina. Dr. Vander Weide has testified in thirty states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

| ELECTRIC, GAS, WATER, OIL COMPANIES | |
|---|---|
| Alcoa Power Generating, Inc. | Maritimes & Northeast Pipeline |
| Alliant Energy and subsidiaries | MidAmerican Energy and subsidiaries |
| AltaLink, L.P. | National Fuel Gas |
| Ameren | Newfoundland Power Inc. |
| American Water Works | Nevada Power Company |
| Atmos Energy and subsidiaries | NICOR |
| BP p.l.c. | North Carolina Natural Gas |
| Central Illinois Public Service | North Shore Gas |
| Citizens Utilities | Northern Natural Gas Company |
| Consolidated Natural Gas and subsidiaries | NOVA Gas Transmission Ltd. |
| Dominion Resources and subsidiaries | PacifiCorp |
| Duke Energy and subsidiaries | Peoples Energy and its subsidiaries |
| Empire District Electric Company | PG&E |
| EPCOR Distribution & Transmission Inc. | Progress Energy |
| EPCOR Energy Alberta Inc. | PSE&G |
| FortisAlberta Inc. | Public Service Company of North Carolina |
| Hope Natural Gas | Sempra Energy/San Diego Gas and Electric |
| Interstate Power Company | South Carolina Electric and Gas |
| Iberdrola Renewables | Southern Company and subsidiaries |
| Iowa Southern | Tennessee-American Water Company |
| Iowa-American Water Company | The Peoples Gas, Light and Coke Co. |
| Iowa-Illinois Gas and Electric | TransCanada |
| Kentucky Power Company | Trans Québec & Maritimes Pipeline Inc. |
| Kentucky-American Water Company | Union Gas |
| Kinder Morgan Energy Partners | United Cities Gas Company |
| | Virginia-American Water Company |
| | Xcel Energy |

| TELECOMMUNICATIONS COMPANIES | |
|---|---|
| ALLTEL and subsidiaries | Phillips County Cooperative Tel. Co. |
| Ameritech (now AT&T new) | Pine Drive Cooperative Telephone Co. |
| AT&T (old) | Roseville Telephone Company (SureWest) |
| Bell Canada/Nortel | SBC Communications (now AT&T new) |
| BellSouth and subsidiaries | Sherburne Telephone Company |
| Centel and subsidiaries | Siemens |
| Cincinnati Bell (Broadwing) | Southern New England Telephone |
| Cisco Systems | Sprint/United and subsidiaries |
| Citizens Telephone Company | Telefónica |
| Concord Telephone Company | Tellabs, Inc. |
| Contel and subsidiaries | The Stentor Companies |
| Deutsche Telekom | U S West (Qwest) |
| GTE and subsidiaries (now Verizon) | Union Telephone Company |
| Heins Telephone Company | United States Telephone Association |
| JDS Uniphase | Valor Telecommunications (Windstream) |

| TELECOMMUNICATIONS COMPANIES | |
|---|---|
| Lucent Technologies | Verizon (Bell Atlantic) and subsidiaries |
| Minnesota Independent Equal Access Corp. | Woodbury Telephone Company |
| NYNEX and subsidiaries (Verizon) | |
| Pacific Telesis and subsidiaries | |

| INSURANCE COMPANIES |
|---|
| Allstate |
| North Carolina Rate Bureau |
| United Services Automobile Association (USAA) |
| The Travelers Indemnity Company |
| Gulf Insurance Company |

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

Early in his career, Dr. Vander Weide helped found University Analytics, Inc., which was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

**PUBLICATIONS**
**JAMES H. VANDER WEIDE**

The Lock-Box Location Problem: a Practical Reformulation, *Journal of Bank Research*, Summer, 1974, pp. 92-96 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren, Gorham and Lamont, 1978.

A Finite Horizon Dynamic Programming Approach to the Telephone Cable Layout Problem, *Conference Record*, 1976 International Conference on Communications (with S. Maier and C. Lam).

A Note on the Optimal Investment Policy of the Regulated Firm, *Atlantic Economic Journal*, Fall, 1976 (with D. Peterson).

A Unified Location Model for Cash Disbursements and Lock-Box Collections, *Journal of Bank Research*, Summer, 1976 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren Gorham and Lamont, 1978. Also reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

Capital Budgeting in the Decentralized Firm,' *Management Science*, Vol. 23, No. 4, December 1976, pp. 433-443 (with S. Maier).

A Monte Carlo Investigation of Characteristics of Optimal Geometric Mean Portfolios, *Journal of Financial and Quantitative Analysis*, June, 1977, pp. 215-233 (with S. Maier and D. Peterson).

A Strategy which Maximizes the Geometric Mean Return on Portfolio Investments, *Management Science*, June, 1977, Vol. 23, No. 10, pp. 1117-1123 (with S. Maier and D. Peterson).

A Decision Analysis Approach to the Computer Lease-Purchase Decision, *Computers and Operations Research*, Vol. 4, No. 3, September, 1977, pp. 167-172 (with S. Maier).

A Practical Approach to Short-run Financial Planning, *Financial Management*, Winter, 1978 (with S. Maier). Reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

Effectiveness of Regulation in the Electric Utility Industry,' *Journal of Economics and Business*, May, 1979 (with F. Tapon).

On the Decentralized Capital Budgeting Problem Under Uncertainty, *Management Science*, September 1979 (with B. Obel).

Expectations Data and the Predictive Value of Interim Reporting: A Comment, *Journal of Accounting Research*, Spring 1980 (with L. D. Brown, J. S. Hughes, and M. S. Rozeff).

General Telephone's Experience with a Short-run Financial Planning Model, *Cash Management Forum*, June 1980, Vol. 6, No. 1 (with J. Austin and S. Maier).

Deregulation and Oligopolistic Price-Quality Rivalry, *American Economic Review*, March 1981 (with J. Zalkind).

A Short-Term Disbursement Forecasting Model, Financial Management, Vol. 10, No. 1, Spring 1981 (with S. Maier and D. Robinson).

Recent Developments in Management Science in Banking, *Management Science*, October 1981 (with K. Cohen and S. Maier).

Incentive Considerations in the Reporting of Leveraged Leases, *Journal of Bank Research*, April 1982 (with J. S. Hughes).

A Decision-Support System for Managing a Short-term Financial Instrument Portfolio, *Journal of Cash Management*, March 1982 (with S. Maier).

An Empirical Bayes Estimate of Market Risk, *Management Science*, July 1982 (with S. Maier and D. Peterson).

The Bond Scheduling Problem of the Multi-subsidiary Holding Company, *Management Science*, July 1982 (with K. Baker).

Deregulation and Locational Rents in Banking:  a Comment, *Journal of Bank Research*, Summer 1983.

What Lockbox and Disbursement Models Really Do, *Journal of Finance*, May 1983 (with S. Maier).

Financial Management in the Short Run, *Handbook of Modern Finance*, edited by Dennis Logue, published by Warren, Gorham, & Lamont, Inc., New York, 1984.

Measuring Investors' Growth Expectations:  Analysts vs. History, *The Journal of Portfolio Management*, Spring 1988 (with W. Carleton).

Entry Auctions and Strategic Behavior under Cross-Market Price Constraints, *International Journal of Industrial Organization*, 20 (2002) 611-629 (with J. Anton and N. Vettas).

Principles for Lifetime Portfolio Selection:  Lessons from Portfolio Theory, *Handbook of Portfolio Construction:  Contemporary Applications of Markowitz Techniques*, John B. Guerard, (Ed.), Springer, forthcoming 2009.

*Managing Corporate Liquidity:  an Introduction to Working Capital Management*, John Wiley and Sons, 1984 (with S. Maier).

## SUMMARY EXPERT TESTIMONY
## JAMES H. VANDER WEIDE

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Empire District Electric Company | Missouri | Jul-12 | ER2012-0345 |
| Atmos Energy | Tennessee | Jul-12 | 12-00064 |
| Mississippi Power Company | Mississippi | Jun-12 | |
| Tennessee-American Water Company | Tennessee | May-12 | 12-00049 |
| Empire District Electric Company | FERC | May-12 | ER12-0345 |
| Newfoundland Power Inc. | Newfoundland and Labrador | Mar-12 | |
| Virginia-American Water Company | Virginia | Feb-11 | PUE-2011-00127 |
| SFPP, L.P. | FERC | Dec-11 | IS11-444-001 |
| Union Gas | Ontario Energy Board | Nov-11 | |
| Mississippi Power Company | FERC | Nov-11 | ER12-337 |
| National Fuel Gas | FERC | Oct-11 | RP12-888-000 |
| Gulf Power Florida | Florida | Jul-11 | 110138-EI |
| Empire District Electric Company | Oklahoma Corporation Commission | Jul-11 | 11-EPDE-856-RTS |
| Atmos Energy (West Texas) | Railroad Commission of Texas | Jun-11 | |
| Atmos Energy (Lubbock) | Railroad Commission of Texas | Jun-11 | |
| Iberdrola Renewables Holdings, Inc. | United States Tax Court | Apr-11 | 525-10 |
| North Carolina Rate Bureau (dwelling fire) | North Carolina Dept. of Insurance | Jan-11 | |
| Atmos Energy | Railroad Commission of Texas | Dec-10 | GUD 10041 |
| Mississippi Power Company | FERC | Oct-10 | |
| Empire District Electric Company | Missouri | Sep-10 | ER-2011-0004 |
| Tennessee-American Water Company | Tennessee | Sep-10 | 10-00189 |
| Empire District Electric Company | Arkansas | Aug-10 | 10-052-U |
| Maritimes & Northeast Pipelines Limited Partnership | National Energy Board (Canada) | Jul-10 | RH 4-2010 |
| Georgia Power Company | Georgia | Jun-10 | 31958 |
| West Virginia American Water Company | West Virginia | Jun-10 | Case No. 10-0920-W-42T |
| Atmos Energy | Mississippi | Apr-10 | 2005-UN-503 |
| BP Pipelines (Alaska) Inc. | FERC | Apr-10 | IS09-348-000 |
| Empire District Electric Company | FERC | Mar-10 | ER10-877-000 |
| Kentucky-American Water Company | Kentucky | Feb-10 | 2010-00036 |
| Virginia-American Water Company | Virginia | Feb-10 | PUE-2010-00001 |
| Virginia Electric and Power | North Carolina | Feb-10 | E-22 SUB 459 |
| SFPP, L.P. | FERC | Dec-09 | ISO9-437-000 |
| Atmos Energy | Missouri | Dec-09 | Gr-2010-0192 |
| Empire District Electric Company | Kansas | Nov-09 | 10-EPDE-314-RTS |
| Empire District Electric Company | Missouri | Nov-09 | ER-2010-0130 |
| Atmos Energy | Kentucky | Oct-09 | 2009-00354 |
| Atmos Energy | Georgia | Oct-09 | 30442 |
| SFPP, L.P. and Calnev Pipeline, L.L.C. | California | Sep-09 | 09-05-014 et al |
| Union Gas | Ontario Energy Board | Sep-09 | EB-2009-0084 |
| Atmos Energy | Mississippi | Sep-09 | 05-UN-503 |
| North Carolina Rate Bureau (workers) | North Carolina Dept. of Insurance | Sep-09 | |
| Sidley Austin LLP, Tellabs, Inc. Securities Litigation | U.S. District Court Northern Dist. Illinois | Aug-09 | C.A. No. 02-C-4356 |
| Duke Energy Carolinas | South Carolina | Jul-09 | 2009-226-E |
| MidAmerican Energy Company | Iowa | Jul-09 | RPU-2009-0003 |
| Duke Enegy Carolinas | North Carolina | Jun-09 | E-7, SUB 909 |
| Empire District Electric Company | Missouri | Jun-09 | ER-2008-009 |
| Terasen Gas Inc. | British Columbia Utilities Commission | May-09 | |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Atmos Energy | Railroad Commission of Texas | Apr-09 | GUD-9869 |
| Progress Energy | Florida | Mar-09 | 090079-EI |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jan-09 | |
| EPCOR, FortisAlberta, AltaLink | Alberta Utilities Commission | Nov-08 | 1578571, ID-85 |
| Trans Québec & Maritimes Pipeline Inc. | Alberta Utilities Commission | Nov-08 | 1578571, ID-85 |
| Kentucky-American Water Company | Kentucky Public Service Commission | Oct-08 | 2008-00427 |
| Atmos Energy | Tennessee Regulatory Authority | Oct-08 | 0800197 |
| North Carolina Rate Bureau (workers compensation) | North Carolina Dept. of Insurance | Aug-08 | |
| Dorsey & Whitney LLP-Williams v. Gannon | Montana 2nd Judicial Dist. Ct. Silver Bow County | Apr-08 | DV-02-201 |
| Atmos Energy | Georgia | Mar-08 | 27163-U |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jan-08 | |
| Trans Québec & Maritimes Pipeline Inc. | National Energy Board (Canada) | Dec-07 | RH-1-2008 |
| Xcel Energy | North Dakota | Dec-07 | PU-07-776 |
| Verizon Southwest | Texas | Nov-07 | 34723 |
| Empire District Electric Company | Missouri | Oct-07 | ER-2008-0093 |
| North Carolina Rate Bureau (workers compensation) | North Carolina Dept. of Insurance | Sep-07 | |
| Verizon North Inc. Contel of the South Inc. | Michigan | Aug-07 | Case No. U-15210 |
| Georgia Power Company | Georgia | Jun-07 | 25060-U |
| Duke Energy Carolinas | North Carolina | May-07 | E-7 Sub 828 et al |
| MidAmerican Energy Company | Iowa | May-07 | SPU-06-5 et al |
| Morrison & Foerster LLP-JDS Uniphase Securities Litigation | U.S. District Court Northern District California | Feb-07 | C-02-1486-CW |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Dec-06 | |
| San Diego Gas & Electric | FERC | Nov-06 | ER07-284-000 |
| North Carolina Rate Bureau (workers compensation) | North Carolina Dept. of Insurance | Aug-06 | |
| Union Electric Company d/b/a AmerenUE | Missouri | Jun-06 | ER-2007-0002 |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | May-06 | |
| North Carolina Rate Bureau (dwelling fire) | North Carolina Dept. of Insurance | Mar-06 | |
| Empire District Electric Company | Missouri | Feb-06 | ER-2006-0315 |
| PacifiCorp Power & Light Company | Washington | Jan-06 | UE-050684 |
| Verizon Maine | Maine | Dec-05 | 2005-155 |
| Winston & Strawn LLP-Cisco Systems Securities Litigation | U.S. District Court Northern District California | Nov-05 | C-01-20418-JW |
| Dominion Virginia Power | Virginia | Nov-05 | PUE-2004-00048 |
| Bryan Cave LLP--Omniplex Comms. v. Lucent Technologies | U.S. District Court Eastern District Missouri | Sep-05 | 04CV00477 ERW |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-05 | |
| Empire District Electric Company | Kansas | Sep-05 | 05-EPDE-980-RTS |
| Verizon Southwest | Texas | Jul-05 | 29315 |
| PG&E Company | FERC | Jul-05 | ER-05-1284 |
| Dominion Hope | West Virginia | Jun-05 | 05-034-G42T |
| Empire District Electric Company | Missouri | Jun-05 | EO-2005-0263 |
| Verizon New England | U.S. District Court New Hampshire | May-05 | 04-CV-65-PB |
| San Diego Gas & Electric | California | May-05 | 05-05-012 |
| Progress Energy | Florida | May-05 | 50078 |
| Verizon Vermont | Vermont | Feb-05 | 6959 |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Feb-05 | |
| Verizon Florida | Florida | Jan-05 | 050059-TL |
| Verizon Illinois | Illinois | Jan-05 | 00-0812 |
| Dominion Resources | North Carolina | Sep-04 | E-22 Sub 412 |
| Tennessee-American Water Company | Tennessee | Aug-04 | 04-00288 |
| Valor Telecommunications of Texas, LP. | New Mexico | Jul-04 | 3495 Phase C |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Alcoa Power Generating Inc. | North Carolina Property Tax Commission | Jul-04 | 02 PTC 162 and 02 PTC 709 |
| PG&E Company | California | May-04 | 04-05-21 |
| Verizon Northwest | Washington | Apr-04 | UT-040788 |
| Verizon Northwest | Washington | Apr-04 | UT-040788 |
| Kentucky-American Water Company | Kentucky | Apr-04 | 2004-00103 |
| MidAmerican Energy | South Dakota | Apr-04 | NG4-001 |
| Empire District Electric Company | Missouri | Apr-04 | ER-2004-0570 |
| Interstate Power and Light Company | Iowa | Mar-04 | RPU-04-01 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Feb-04 | |
| Northern Natural Gas Company | FERC | Feb-04 | RP04-155-000 |
| Verizon New Jersey | New Jersey | Jan-04 | TO00060356 |
| Verizon | FCC | Jan-04 | 03-173, FCC 03-224 |
| Verizon | FCC | Dec-03 | 03-173, FCC 03-224 |
| Verizon California Inc. | California | Nov-03 | R93-04-003,I93-04-002 |
| Phillips County Telephone Company | Colorado | Nov-03 | 03S-315T |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Oct-03 | |
| PG&E Company | FERC | Oct-03 | ER04-109-000 |
| Allstate Insurance Company | Texas Department of Insurance | Sep-03 | 2568 |
| Verizon Northwest Inc. | Washington | Jul-03 | UT-023003 |
| Empire District Electric Company | Oklahoma | Jul-03 | Case No. PUD 200300121 |
| Verizon Virginia Inc. | FCC | Apr-03 | CC-00218,00249,00251 |
| North Carolina Rate Bureau (dwelling fire) | North Carolina Dept. of Insurance | Apr-03 | |
| Northern Natural Gas Company | FERC | Apr-03 | RP03-398-000 |
| MidAmerican Energy | Iowa | Apr-03 | RPU-03-1, WRU-03-25-156 |
| PG&E Company | FERC | Mar-03 | ER03666000 |
| Verizon Florida Inc. | Florida | Feb-03 | 981834-TP/990321-TP |
| Verizon North | Indiana | Feb-03 | 42259 |
| San Diego Gas & Electric | FERC | Feb-03 | ER03-601000 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jan-03 | |
| Gulf Insurance Company | Superior Court, North Carolina | Jan-03 | 2000-CVS-3558 |
| PG&E Company | FERC | Jan-03 | ER03409000 |
| Verizon New England Inc. New Hampshire | New Hampshire | Dec-02 | DT 02-110 |
| Verizon Northwest | Washington | Dec-02 | UT 020406 |
| PG&E Company | California | Dec-02 | |
| MidAmerican Energy | Iowa | Nov-02 | RPU-02-3, 02-8 |
| MidAmerican Energy | Iowa | Nov-02 | RPU-02-10 |
| Verizon Michigan | US District Court Eastern District of Michigan | Sep-02 | Civil Action No. 00-73208 |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-02 | |
| Verizon New England Inc. New Hampshire | New Hampshire | Aug-02 | DT 02-110 |
| Interstate Power Company | Iowa Board of Tax Review | Jul-02 | 832 |
| PG&E Company | California | May-02 | A 02-05-022 et al |
| Verizon New England Inc. Massachusetts | FCC | May-02 | EB 02 MD 006 |
| Verizon New England Inc. Rhode Island | Rhode Island | May-02 | Docket No. 2681 |
| NEUMEDIA, INC. | US Bankruptcy Court Southern District W. Virginia | Apr-02 | Case No. 01-20873 |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Mar-02 | |
| MidAmerican Energy Company | Iowa | Mar-02 | RPU 02 2 |
| North Carolina Natural Gas Company | North Carolina | Feb-02 | G21 Sub 424 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jan-02 | |
| Verizon Pennsylvania | Pennsylvania | Dec-01 | R-00016683 |
| Verizon Florida | Florida | Nov-01 | 99064B-TP |
| PG&E Company | FERC | Nov-01 | ER0166000 |
| Verizon Delaware | Delaware | Oct-01 | 96-324 Phase II |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Florida Power Corporation | Florida | Sep-01 | 000824-EL |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-01 | |
| Verizon Washington DC | District of Columbia | Jul-01 | 962 |
| Verizon Virginia | FCC | Jul-01 | CC-00218,00249,00251 |
| Sherburne County Rural Telephone Company | Minnesota | Jul-01 | P427/CI-00-712 |
| Verizon New Jersey | New Jersey | Jun-01 | TO01020095 |
| Verizon Maryland | Maryland | May-01 | 8879 |
| Verizon Massachusetts | Massachusetts | May-01 | DTE 01-20 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Apr-01 | |
| PG&E Company | FERC | Mar-01 | ER011639000 |
| Maupin Taylor & Ellis P.A. | National Association of Securities Dealers | Jan-01 | 99-05099 |
| USTA | FCC | Oct-00 | RM 10011 |
| Verizon New York | New York | Oct-00 | 98-C-1357 |
| Verizon New Jersey | New Jersey | Oct-00 | TO00060356 |
| PG&E Company | FERC | Oct-00 | ER0166000 |
| Verizon New Jersey | New Jersey | Sep-00 | TO99120934 |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-00 | |
| PG&E Company | California | Aug-00 | 00-05-018 |
| Verizon New York | New York | Jul-00 | 98-C-1357 |
| PG&E Company | California | May-00 | 00-05-013 |
| PG&E Company | FERC | Mar-00 | ER00-66-000 |
| PG&E Company | FERC | Mar-00 | ER99-4323-000 |
| Bell Atlantic | New York | Feb-00 | 98-C-1357 |
| USTA | FCC | Jan-00 | 94-1, 96-262 |
| MidAmerican Energy | Iowa | Nov-99 | SPU-99-32 |
| PG&E Company | California | Nov-99 | 99-11-003 |
| PG&E Company | FERC | Nov-99 | ER973255,981261,981685 |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-99 | |
| MidAmerican Energy | Illinois | Sep-99 | 99-0534 |
| PG&E Company | FERC | Sep-99 | ER99-4323-000 |
| MidAmerican Energy | FERC | Jul-99 | ER99-3887 |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Jun-99 | |
| Bell Atlantic | Vermont | May-99 | 6167 |
| Nevada Power Company | FERC | May-99 | |
| Bell Atlantic, GTE, US West | FCC | Apr-99 | CC98-166 |
| Nevada Power Company | Nevada | Apr-99 | |
| Bell Atlantic, GTE, US West | FCC | Mar-99 | CC98-166 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Mar-99 | |
| PG&E Company | FERC | Mar-99 | ER99-2326-000 |
| MidAmerican Energy | Illinois | Mar-99 | 099-0310 |
| PG&E Company | FERC | Feb-99 | ER99-2358,2087,2351 |
| MidAmerican Energy | US District Court, District of Nebraska | Feb-99 | 8:97 CV 346 |
| Bell Atlantic, GTE, US West | FCC | Jan-99 | CC98-166 |
| The Southern Company | FERC | Jan-99 | ER98-1096 |
| Deutsche Telekom | Germany | Nov-98 | |
| Telefonica | Spain | Nov-98 | |
| Cincinnati Bell Telephone Company | Ohio | Oct-98 | 96899TPALT |
| MidAmerican Energy | Iowa | Sep-98 | RPU 98-5 |
| MidAmerican Energy | South Dakota | Sep-98 | NG98-011 |
| MidAmerican Energy | Iowa | Sep-98 | SPU 98-8 |
| GTE Florida Incorporated | Florida | Aug-98 | 980696-TP |
| GTE North and South | Illinois | Jun-98 | 960503 |
| GTE Midwest Incorporated | Missouri | Jun-98 | TO98329 |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| GTE North and South | Illinois | May-98 | 960503 |
| MidAmerican Energy | Iowa Board of Tax Review | May-98 | 835 |
| San Diego Gas & Electric | California | May-98 | 98-05-024 |
| GTE Midwest Incorporated | Nebraska | Apr-98 | C1416 |
| Carolina Telephone | North Carolina | Mar-98 | P100Sub133d |
| GTE Southwest | Texas | Feb-98 | 18515 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Feb-98 | P100sub133d |
| Public Service Electric & Gas | New Jersey | Feb-98 | PUC734897N,-734797N,BPUEO97070461,-07070462 |
| GTE North | Minnesota | Dec-97 | P999/M97909 |
| GTE Northwest | Oregon | Dec-97 | UM874 |
| The Southern Company | FERC | Dec-97 | ER981096000 |
| GTE North | Pennsylvania | Nov-97 | A310125F0002 |
| Bell Atlantic | Rhode Island | Nov-97 | 2681 |
| GTE North | Indiana | Oct-97 | 40618 |
| GTE North | Minnesota | Oct-97 | P442,407/5321/CI961541 |
| GTE Southwest | New Mexico | Oct-97 | 96310TC,96344TC |
| GTE Midwest Incorporated | Iowa | Sep-97 | RPU-96-7 |
| North Carolina Rate Bureau (workers) | North Carolina Dept. of Insurance | Sep-97 | |
| GTE Hawaiian Telephone | Hawaii | Aug-97 | 7702 |
| The Stentor Companies | Canadian Radio-television and Telecommunications Commission | Jul-97 | CRTC97-11 |
| New England Telephone | Vermont | Jul-97 | 5713 |
| Bell-Atlantic-New Jersey | New Jersey | Jun-97 | TX95120631 |
| Nevada Bell | Nevada | May-97 | 96-9035 |
| New England Telephone | Maine | Apr-97 | 96-781 |
| GTE North, Inc. | Michigan | Apr-97 | U11281 |
| Bell Atlantic-Virginia | Virginia | Apr-97 | 970005 |
| Cincinnati Bell Telephone | Ohio | Feb-97 | 96899TPALT |
| Bell Atlantic - Pennsylvania | Pennsylvania | Feb-97 | A310203,213,236,258F002 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Feb-97 | |
| Bell Atlantic-Washington, D.C. | District of Columbia | Jan-97 | 962 |
| Pacific Bell, Sprint, US West | FCC | Jan-97 | CC 96-45 |
| United States Telephone Association | FCC | Jan-97 | CC 96-262 |
| Bell Atlantic-Maryland | Maryland | Jan-97 | 8731 |
| Bell Atlantic-West Virginia | West Virginia | Jan-97 | 961516, 1561, 1009TPC,961533TT |
| Poe, Hoof, & Reinhardt | Durham Cnty Superior Court Kountis vs. Circle K | Jan-97 | 95CVS04754 |
| Bell Atlantic-Delaware | Delaware | Dec-96 | 96324 |
| Bell Atlantic-New Jersey | New Jersey | Nov-96 | TX95120631 |
| Carolina Power & Light Company | FERC | Nov-96 | OA96-198-000 |
| New England Telephone | Massachusetts | Oct-96 | DPU 96-73/74,-75, -80/81, -83, -94 |
| New England Telephone | New Hampshire | Oct-96 | 96-252 |
| Bell Atlantic-Virginia | Virginia | Oct-96 | 960044 |
| Citizens Utilities | Illinois | Sep-96 | 96-0200, 96-0240 |
| Union Telephone Company | New Hampshire | Sep-96 | 95-311 |
| Bell Atlantic-New Jersey | New Jersey | Sep-96 | TO-96070519 |
| New York Telephone | New York | Sep-96 | 95-C-0657, 94-C-0095,91-C-1174 |
| North Carolina Rate Bureau (workers comp) | North Carolina Dept. of Insurance | Sep-96 | |
| MidAmerican Energy Company | Illinois | Sep-96 | 96-0274 |
| MidAmerican Energy Company | Iowa | Sep-96 | RPU96-8 |
| United States Telephone Association | FCC | Mar-96 | AAD-96.28 |
| United States Telephone Association | FCC | Mar-96 | CC 94-1 PhaseIV |
| Bell Atlantic - Maryland | Maryland | Mar-96 | 8715 |
| Nevada Bell | Nevada | Mar-96 | 96-3002 |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Mar-96 | |
| Carolina Tel. and Telegraph Co, Central Tel Co | North Carolina | Feb-96 | P7 sub 825, P10 sub 479 |
| Oklahoma Rural Telephone Coalition | Oklahoma | Oct-95 | PUD950000119 |
| BellSouth | Tennessee | Oct-95 | 95-02614 |
| Wake County, North Carolina | US District Court, Eastern Dist. NC | Oct-95 | 594CV643H2 |
| Bell Atlantic - District of Columbia | District of Columbia | Sep-95 | 814 Phase IV |
| South Central Bell Telephone Company | Tennessee | Aug-95 | 95-02614 |
| GTE South | Virginia | Jun-95 | 95-0019 |
| Roseville Telephone Company | California | May-95 | A.95-05-030 |
| Bell Atlantic - New Jersey | New Jersey | May-95 | TX94090388 |
| Cincinnati Bell Telephone Company | Ohio | May-95 | 941695TPACE |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | May-95 | 727 |
| Northern Illinois Gas | Illinois | May-95 | 95-0219 |
| South Central Bell Telephone Company | Kentucky | Apr-95 | 94-121 |
| Midwest Gas | South Dakota | Mar-95 | |
| Virginia Natural Gas, Inc. | Virginia | Mar-95 | PUE940054 |
| Hope Gas, Inc. | West Virginia | Mar-95 | 95-0003G42T |
| The Peoples Natural Gas Company | Pennsylvania | Feb-95 | R-943252 |
| and Coke Co., North Shore Gas, Iowa-Illinois Gas | Illinois | Jan-95 | 94-0403 |
| and Electric, Central Illinois Public Service, | Illinois | Jan-95 | 94-0403 |
| Northern Illinois Gas, The Peoples Gas, Light | Illinois | Jan-95 | 94-0403 |
| United Cities Gas, and Interstate Power | Illinois | Jan-95 | 94-0403 |
| Cincinnati Bell Telephone Company | Kentucky | Oct-94 | 94-355 |
| Midwest Gas | Nebraska | Oct-94 | |
| Midwest Power | Iowa | Sep-94 | RPU-94-4 |
| Bell Atlantic | FCC | Aug-94 | CS 94-28, MM 93-215 |
| Midwest Gas | Iowa | Jul-94 | RPU-94-3 |
| Bell Atlantic | FCC | Jun-94 | CC 94-1 |
| Nevada Power Company | Nevada | Jun-94 | 93-11045 |
| Cincinnati Bell Telephone Company | Ohio | Mar-94 | 93-551-TP-CSS |
| Cincinnati Bell Telephone Company | Ohio | Mar-94 | 93-432-TP-ALT |
| GTE South/Contel | Virginia | Feb-94 | PUC9300036 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Feb-94 | 689 |
| Bell of Pennsylvania | Pennsylvania | Jan-94 | P930715 |
| GTE South | South Carolina | Jan-94 | 93-504-C |
| United Telephone-Southeast | Tennessee | Jan-94 | 93-04818 |
| C&P of VA, GTE South, Contel, United Tel. SE | Virginia | Sep-93 | PUC920029 |
| Bell Atlantic, NYNEX, Pacific Companies | FCC | Aug-93 | MM 93-215 |
| C&P, Centel, Contel, GTE, & United | Virginia | Aug-93 | PUC920029 |
| Chesapeake & Potomac Tel Virginia | Virginia | Aug-93 | 93-00- |
| GTE North | Illinois | Jul-93 | 93-0301 |
| Midwest Power | Iowa | Jul-93 | INU-93-1 |
| Midwest Power | South Dakota | Jul-93 | EL93-016 |
| Chesapeake & Potomac Tel. Co. DC | District of Columbia | Jun-93 | 926 |
| Cincinnati Bell | Ohio | Jun-93 | 93432TPALT |
| North Carolina Rate Bureau (dwelling fire) | North Carolina Dept. of Insurance | Jun-93 | 671 |
| North Carolina Rate Bureau (homeowners) | North Carolina Dept. of Insurance | Jun-93 | 670 |
| Pacific Bell Telephone Company | California | Mar-93 | 92-05-004 |
| Minnesota Independent Equal Access Corp. | Minnesota | Mar-93 | P3007/GR931 |
| South Central Bell Telephone Company | Tennessee | Feb-93 | 92-13527 |
| South Central Bell Telephone Company | Kentucky | Dec-92 | 92-523 |
| Southern New England Telephone Company | Connecticut | Nov-92 | 92-09-19 |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Chesapeake & Potomac Tel. Co.CDC | District of Columbia | Nov-92 | 814 |
| Diamond State Telephone Company | Delaware | Sep-92 | PSC 92-47 |
| New Jersey Bell Telephone Company | New Jersey | Sep-92 | TO-92030958 |
| Allstate Insurance Company | New Jersey Dept. of Insurance | Sep-92 | INS 06174-92 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Aug-92 | 650 |
| North Carolina Rate Bureau (workers' comp) | North Carolina Dept. of Insurance | Aug-92 | 647 |
| Midwest Gas Company | Minnesota | Aug-92 | G010/GR92710 |
| Pennsylvania-American Water Company | Pennsylvania | Jul-92 | R-922428 |
| Central Telephone Co. of Florida | Florida | Jun-92 | 920310-TL |
| C&P of VA, GTE South, Contel, United Tel. SE | Virginia | Jun-92 | PUC920029 |
| Chesapeake & Potomac Tel. Co. Maryland | Maryland | May-92 | 8462 |
| Pacific Bell Telephone Company | California | Apr-92 | 92-05-004 |
| Iowa Power Inc. | Iowa | Mar-92 | RPU-92-2 |
| Contel of Texas | Texas | Feb-92 | 10646 |
| Southern Bell Telephone Company | Florida | Jan-92 | 880069-TL |
| Nevada Power Company | Nevada | Jan-92 | 92-1067 |
| GTE South | Georgia | Dec-91 | 4003-U |
| GTE South | Georgia | Dec-91 | 4110-U |
| Allstate Insurance Company (property) | Texas Dept. of Insurance | Dec-91 | 1846 |
| IPS Electric | Iowa | Oct-91 | RPU-91-6 |
| GTE South | Tennessee | Aug-91 | 91-05738 |
| North Carolina Rate Bureau (workers' comp) | North Carolina Dept. of Insurance | Aug-91 | 609 |
| Midwest Gas Company | Iowa | Jul-91 | RPU-91-5 |
| Pennsylvania-American Water Company | Pennsylvania | Jun-91 | R-911909 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jun-91 | 606 |
| Allstate Insurance Company | California Dept. of Insurance | May-91 | RCD-2 |
| Nevada Power Company | Nevada | May-91 | 91-5055 |
| Kentucky Power Company | Kentucky | Apr-91 | 91-066 |
| Chesapeake & Potomac Tel. Co.CD.C. | District of Columbia | Feb-91 | 850 |
| Allstate Insurance Company | New Jersey Dept. of Insurance | Jan-91 | INS-9536-90 |
| GTE South | South Carolina | Nov-90 | 90-698-C |
| Southern Bell Telephone Company | Florida | Oct-90 | 880069-TL |
| GTE South | West Virginia | Aug-90 | 90-522-T-42T |
| North Carolina Rate Bureau (workers' comp) | North Carolina Dept. of Insurance | Aug-90 | R90-08- |
| The Travelers Indemnity Company | Pennsylvania Dept. of Insurance | Aug-90 | R-90-06-23 |
| Chesapeake & Potomac Tel. Co.-Maryland | Maryland | Jul-90 | 8274 |
| Allstate Insurance Company | Pennsylvania Dept. of Insurance | Jul-90 | R90-07-01 |
| Central Tel. Co. of Florida | Florida | Jun-90 | 89-1246-TL |
| Citizens Telephone Company | North Carolina | Jun-90 | P-12, SUB 89 |
| North Carolina Rate Bureau (auto) | North Carolina Dept. of Insurance | Jun-90 | 568 |
| Iowa Resources, Inc. and Midwest Energy | Iowa | Jun-90 | SPU-90-5 |
| Contel of Illinois | Illinois | May-90 | 90-0128 |
| Southern New England Tel. Co. | Connecticut | Apr-90 | 89-12-05 |
| Bell Atlantic | FCC | Apr-90 | 89-624 II |
| Pennsylvania-American Water Company | Pennsylvania | Mar-90 | R-901652 |
| Bell Atlantic | FCC | Feb-90 | 89-624 |
| GTE South | Tennessee | Jan-90 | |
| Allstate Insurance Company | California Dept. of Insurance | Jan-90 | REB-1002 |
| Bell Atlantic | FCC | Nov-89 | 87-463 II |
| Allstate Insurance Company | California Dept. of Insurance | Sep-89 | REB-1006 |
| Pacific Bell | California | Mar-89 | 87-11-0033 |
| Iowa Power & Light | Iowa | Dec-88 | RPU-88-10 |
| Pacific Bell | California | Oct-88 | 88-05-009 |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| Southern Bell | Florida | Apr-88 | 880069TL |
| Carolina Independent Telcos. | North Carolina | Apr-88 | P-100, Sub 81 |
| United States Telephone Association | U. S. Congress | Apr-88 | |
| Carolina Power & Light | South Carolina | Mar-88 | 88-11-E |
| New Jersey Bell Telephone Co. | New Jersey | Feb-88 | 87050398 |
| Carolina Power & Light | FERC | Jan-88 | ER-88-224-000 |
| Carolina Power & Light | North Carolina | Dec-87 | E-2, Sub 537 |
| Bell Atlantic | FCC | Nov-87 | 87-463 |
| Diamond State Telephone Co. | Delaware | Jul-87 | 86-20 |
| Central Telephone Co. of Nevada | Nevada | Jun-87 | 87-1249 |
| ALLTEL | Florida | Apr-87 | 870076-PU |
| Southern Bell | Florida | Apr-87 | 870076-PU |
| Carolina Power & Light | North Carolina | Apr-87 | E-2, Sub 526 |
| So. New England Telephone Co. | Connecticut | Mar-87 | 87-01-02 |
| Northern Illinois Gas Co. | Illinois | Mar-87 | 87-0032 |
| Bell of Pennsylvania | Pennsylvania | Feb-87 | 860923 |
| Carolina Power & Light | FERC | Jan-87 | ER-87-240-000 |
| Bell South | NTIA | Dec-86 | 61091-619 |
| Heins Telephone Company | North Carolina | Oct-86 | P-26, Sub 93 |
| Public Service Co. of NC | North Carolina | Jul-86 | G-5, Sub 207 |
| Bell Atlantic | FCC | Feb-86 | 84-800 III |
| BellSouth | FCC | Feb-86 | 84-800 III |
| ALLTEL Carolina, Inc | North Carolina | Feb-86 | P-118, Sub 39 |
| ALLTEL Georgia, Inc. | Georgia | Jan-86 | 3567-U |
| ALLTEL Ohio | Ohio | Jan-86 | 86-60-TP-AIR |
| Western Reserve Telephone Co. | Ohio | Jan-86 | 85-1973-TP-AIR |
| New England Telephone & Telegraph | Maine | Dec-85 | |
| ALLTEL-Florida | Florida | Oct-85 | 850064-TL |
| Iowa Southern Utilities | Iowa | Oct-85 | RPU-85-11 |
| Bell Atlantic | FCC | Sep-85 | 84-800 II |
| Pacific Telesis | FCC | Sep-85 | 84-800 II |
| Pacific Bell | California | Apr-85 | 85-01-034 |
| United Telephone Co. of Missouri | Missouri | Apr-85 | TR-85-179 |
| South Carolina Generating Co. | FERC | Apr-85 | 85-204 |
| South Central Bell | Kentucky | Mar-85 | 9160 |
| New England Telephone & Telegraph | Vermont | Mar-85 | 5001 |
| Chesapeake & Potomac Telephone Co. | West Virginia | Mar-85 | 84-747 |
| Chesapeake & Potomac Telephone Co. | Maryland | Jan-85 | 7851 |
| Central Telephone Co. of Ohio | Ohio | Dec-84 | 84-1431-TP-AIR |
| Ohio Bell | Ohio | Dec-84 | 84-1435-TP-AIR |
| Carolina Power & Light Co. | FERC | Dec-84 | ER85-184000 |
| BellSouth | FCC | Nov-84 | 84-800 I |
| Pacific Telesis | FCC | Nov-84 | 84-800 I |
| New Jersey Bell | New Jersey | Aug-84 | 848-856 |
| Southern Bell | South Carolina | Aug-84 | 84-308-C |
| Pacific Power & Light Co. | Montana | Jul-84 | 84.73.8 |
| Carolina Power & Light Co. | South Carolina | Jun-84 | 84-122-E |
| Southern Bell | Georgia | Mar-84 | 3465-U |
| Carolina Power & Light Co. | North Carolina | Feb-84 | E-2, Sub 481 |
| Southern Bell | North Carolina | Jan-84 | P-55, Sub 834 |
| South Carolina Electric & Gas | South Carolina | Nov-83 | 83-307-E |
| Empire Telephone Co. | Georgia | Oct-83 | 3343-U |
| Southern Bell | Georgia | Aug-83 | 3393-U |
| Carolina Power & Light Co. | FERC | Aug-83 | ER83-765-000 |

| SPONSOR | JURISDICTION | DATE | DOCKET NO. |
|---|---|---|---|
| General Telephone Co. of the SW | Arkansas | Jul-83 | 83-147-U |
| Heins Telephone Co. | North Carolina | Jul-83 | No.26 Sub 88 |
| General Telephone Co. of the NW | Washington | Jul-83 | U-82-45 |
| Leeds Telephone Co. | Alabama | Apr-83 | 18578 |
| General Telephone Co. of California | California | Apr-83 | 83-07-02 |
| North Carolina Natural Gas | North Carolina | Apr-83 | G21 Sub 235 |
| Carolina Power & Light | South Carolina | Apr-83 | 82-328-E |
| Eastern Illinois Telephone Co. | Illinois | Feb-83 | 83-0072 |
| Carolina Power & Light | North Carolina | Feb-83 | E-2 Sub 461 |
| New Jersey Bell | New Jersey | Dec-82 | 8211-1030 |
| Southern Bell | Florida | Nov-82 | 820294-TP |
| United Telephone of Missouri | Missouri | Nov-82 | TR-83-135 |
| Central Telephone Co. of NC | North Carolina | Nov-82 | P-10 Sub 415 |
| Concord Telephone Company | North Carolina | Nov-82 | P-16 Sub 146 |
| Carolina Telephone & Telegraph | North Carolina | Aug-82 | P-7, Sub 670 |
| Central Telephone Co. of Ohio | Ohio | Jul-82 | 82-636-TP-AIR |
| Southern Bell | South Carolina | Jul-82 | 82-294-C |
| General Telephone Co. of the SW | Arkansas | Jun-82 | 82-232-U |
| General Telephone Co. of Illinois | Illinois | Jun-82 | 82-0458 |
| General Telephone Co. of the SW | Oklahoma | Jun-82 | 27482 |
| Empire Telephone Co. | Georgia | May-82 | 3355-U |
| Mid-Georgia Telephone Co. | Georgia | May-82 | 3354-U |
| General Telephone Co. of the SW | Texas | Apr-82 | 4300 |
| General Telephone Co. of the SE | Alabama | Jan-82 | 18199 |
| Carolina Power & Light Co. | South Carolina | Jan-82 | 81-163-E |
| Elmore-Coosa Telephone Co. | Alabama | Nov-81 | 18215 |
| General Telephone Co. of the SE | North Carolina | Sep-81 | P-19, Sub 182 |
| United Telephone Co. of Ohio | Ohio | Sep-81 | 81-627-TP-AIR |
| General Telephone Co. of the SE | South Carolina | Sep-81 | 81-121-C |
| Carolina Telephone & Telegraph | North Carolina | Aug-81 | P-7, Sub 652 |
| Southern Bell | North Carolina | Aug-81 | P-55, Sub 794 |
| Woodbury Telephone Co. | Connecticut | Jul-81 | 810504 |
| Central Telephone Co. of Virginia | Virginia | Jun-81 | 810030 |
| United Telephone Co. of Missouri | Missouri | May-81 | TR-81-302 |
| General Telephone Co. of the SE | Virginia | Apr-81 | 810003 |
| New England Telephone | Vermont | Mar-81 | 4546 |
| Carolina Telephone & Telegraph | North Carolina | Aug-80 | P-7, Sub 652 |
| Southern Bell | North Carolina | Aug-80 | P-55, Sub 784 |
| General Telephone Co. of the SW | Arkansas | Jun-80 | U-3138 |
| General Telephone Co. of the SE | Alabama | May-80 | 17850 |
| Southern Bell | North Carolina | Oct-79 | P-55, Sub 777 |
| Southern Bell | Georgia | Mar-79 | 3144-U |
| General Telephone Co. of the SE | Virginia | Mar-76 | 810038 |
| General Telephone Co. of the SW | Arkansas | Feb-76 | U-2693, U-2724 |
| General Telephone Co. of the SE | Alabama | Sep-75 | 17058 |
| General Telephone Co. of the SE | South Carolina | Jun-75 | D-18269 |

**EXHIBIT 23**
**APPENDIX 2**
**ESTIMATING THE EXPECTED RISK PREMIUM ON UTILITY STOCKS USING THE DCF MODEL**

The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

**EQUATION 3**

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

| | | |
|---|---|---|
| $P_B$ | = | Bond price; |
| C | = | Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually); |
| F | = | Face value of the bond; |

| | | |
|---|---|---|
| i | = | The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and |
| n | = | The number of periods before the bond matures. |

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

**EQUATION 4**

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

| | | |
|---|---|---|
| $P_S$ | = | Current price of the firm's stock; |
| $D_1, D_2 \ldots D_n$ | = | Expected annual dividend per share on the firm's stock; |
| $P_n$ | = | Price per share of stock at the time the investor expects to sell the stock; and |
| k | = | Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return. |

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where *k* is the cost of equity, $D_1$ is the expected next period annual dividend, $P_s$ is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term $D_1/P_s$ is called the dividend yield component of the annual DCF model, and the term *g* is called the growth component of the annual DCF model.

The annual DCF model is only a correct expression for the present value of future dividends if dividends are paid annually at the end of each year. Since most industrial and utility firms pay dividends quarterly, the annual DCF model produces downwardly biased estimates of the cost of equity. Investors can expect to earn a higher annual effective return on an investment in a firm that pays quarterly dividends than in one which pays the same amount of dollar dividends once at the end of each year.

The Dividend Component

The quarterly DCF model requires an estimate of the expected dividends for the next four quarters. I estimated the expected dividends for the next four quarters by multiplying the actual dividends for the last four quarters by the factor, (1 + the growth rate, g).

The Growth Component

To estimate the growth component of the DCF model, I used the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Financial. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent five-year forecasts of EPS growth. I/B/E/S is a firm that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

I relied on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth. To test whether investors use analysts' growth forecasts to estimate future dividend and earnings growth, I prepared a study in conjunction with Willard T. Carleton, Karl Eller Professor of Finance at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus Historical Growth Extrapolation," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

In our paper, we describe how we first performed a correlation analysis to identify the historically-oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the consensus analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

My study has been updated to include more recent data. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

The Price Component

To measure the price component of the DCF model, I used a simple average of the monthly high and low stock prices for each firm over a three-month period. These high and low stock prices were obtained from Thomson Financial. I used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

# EXHIBIT 24
# APPENDIX 3
# THE SENSITIVITY OF THE FORWARD-LOOKING REQUIRED EQUITY RISK PREMIUM ON UTILITY STOCKS TO CHANGES IN INTEREST RATES

My estimate of the required equity risk premium on utility stocks is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

| | | |
|---|---|---|
| $RP_{COMP}$ | = | the required risk premium on an equity investment in the comparable utilities, |
| $DCF_{COMP}$ | = | average DCF expected rate of return on a portfolio of comparable utilities; and |
| $I_B$ | = | the yield to maturity on an investment in long-term U.S. Treasury bonds. |

Electric Company Ex Ante Risk Premium Analysis. For my electric company ex ante risk premium analysis, I begin with the Moody's group of twenty-four electric companies shown in Table 1. I use the Moody's group of electric companies because they are a widely followed group of electric utilities, and use of this constant group greatly simplifies the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. The exhibit in the testimony displays the average DCF expected return on an investment in the portfolio of electric companies and the yield to maturity on long-term Treasury bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I perform a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on long-term Treasury bonds, using the equation,

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

| | | |
|---|---|---|
| $RP_{COMP}$ | = | risk premium on comparable company group; |
| $I_B$ | = | yield to maturity on long-term U.S. Treasury bonds; |
| e | = | a random residual; and |
| a, b | = | coefficients estimated by the regression procedure. |

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I make adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my regression analysis of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \underset{(13.88)}{10.16} - \underset{(-7.96)}{.889} \times I_B$$

[11] $R^2$ = 29.7 percent.

Using the forecast 2.95 percent yield to maturity on long-term Canada bonds obtained from Consensus Economics as of May 2012, the regression equation produces an ex ante risk premium equal to 7.54 percent (10.16 – .889 x 2.95 = 7.54).

<u>Natural Gas Company Ex Ante Risk Premium Analysis</u>. I also conduct an ex ante risk premium study applied to a natural gas proxy group following the procedures described above. To select my ex ante risk premium natural gas proxy group of companies, I use the same criteria that I use when estimating the DCF cost of equity, namely, I select all the companies in Value Line's groups of natural gas companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have at least two analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety

**[11]** The t-statistics are shown in parentheses.

Rank of 1, 2, or 3; and (5) are not the subject of a merger that has not been completed. The exhibit in the testimony displays the results of my ex ante risk premium study, showing the average DCF expected return on an investment in the portfolio of natural gas companies and the yield to maturity on long-term Treasury bonds in each month.[12]

Based on my knowledge of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy natural gas companies as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \underset{(16.32)}{10.87} - \underset{(-7.715)}{.966} \times I_B. \qquad R^2 = 26.5 \text{ percent}$$

[13]

Using the 2.95 percent forecast yield to maturity on long-term Canada bonds, the regression equation produces an ex ante risk premium equal to 8.0 percent (10.87 – .966 x 2.95 = 8.0).

**[12]** My two ex ante risk premium studies cover slightly different time periods, with the natural gas company risk premium study extending over a longer period of time, because I began doing an ex ante study using natural gas companies before I began performing a similar study for the electric companies.

**[13]** The t-statistics are shown in parentheses.

**TABLE 1**
**MOODY'S ELECTRIC COMPANIES**

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these twenty-four companies, I do not include companies in my ex ante risk premium DCF analysis in months in which there are insufficient data to perform a DCF analysis. In addition, since the beginning period of my study, several companies have disappeared through mergers and acquisitions.

# Appendix H

# EVIDENCE OF FBCU REGARDING BUSINESS RISK FACING FEI

## 1. INTRODUCTION

The Commission's Minimum Filing Requirements ("MFR"), as determined in Order No. G-72-12, specified a number of filing requirements related to business risk:

> 2. *"Business risks faced by a utility in British Columbia.*
>
>    a. *Present business risks:*
>       - i. *Itemized listing of each risk with full explanation,*
>       - ii. *Significance and impact of each risk to a utility,*
>       - iii. *Ranking of the business risks,*
>       - iv. *Business risks faced by all utilities in Canada, and*
>       - v. *Business risks unique to British Columbia.*
>
>    b. *Changes in business risks in the last 5 years and explanation.*
>
> 3. *Changes in:*
>
>    b. *provincial legislative and policy environment in BC, and*
>
>    c. *the utility's business and operations since the last Commission Decision on the capital structure and return on equity for a benchmark utility (December 16, 2009 Decision on Terasen Utilities).*
>
>    *….*
>
> 4. *Business risk ranking and rationale by industry sector - electricity, natural gas, alternative energy providers.*
>
> 5. *Change in business risks as a result of changes to business profile."*

Ms. McShane, in her evidence, defines business risk generally and explains how the overall business risk facing FortisBC Energy Inc. ("FEI") affects FEI's cost of capital. She articulates how business risk for FEI is the Company's ability to recover (i) the capital investments it has made to serve customers over the long-term, and (ii) an appropriate return on those investments.[1] Dr. Vander Weide provides a similar definition.[2] This Appendix describes in greater detail FEI's business, trends, and the environment in which FEI operates, which informs the business risk facing FEI as a natural gas utility in BC. Where applicable, we have discussed differences among various jurisdictions.[3]

A natural gas utility's primary investments have a useful life that extends over a long period of time. Therefore, when evaluating the business risk of a natural gas distribution utility, it is the longer-term fundamental business risks that must be given primary consideration. The business risk of a natural gas utility like FEI is closely tied to the volume of natural gas (throughput) flowing through the FEI system, which is the metric for FEI's product demand. Throughput is the vehicle, from variable rates charged to customers, by which almost all of FEI's investments are recovered.

[1] Appendix F, page 11
[2] Appendix G, page 11
[3] e.g. Ontario, Quebec and Alberta

There are many contributing factors that determine a utility's throughput levels and affect a utility's overall business risk. A number of factors have long been present for FEI, such as: the competitiveness of natural gas to alternative energy sources, namely electricity[4], with a focus on attributes such as price, reliability and ease of use; and, FEI's ability to attract customers and retain its customer base. These risks remain relevant today. In 2009, FEI also identified business risks that had taken on new prominence since the 2005 ROE proceeding, and which also remain relevant today. Government policy developments and issues relating to First Nations have affected FEI's business in significant ways. FEI identified that the energy forms and technologies employed to serve the energy needs of homes and businesses are changing. Drivers of this change include economic factors, technology advancements, customers' preferences and expectations, and government policies. Considerations such as Greenhouse Gas ("GHG") emissions and government policy increasingly impact the competitive position of a fuel or energy source relative to alternatives.

A favourable development for FEI since 2009 is the "shale gas revolution" that has contributed to the present low natural gas commodity prices in North America and has made natural gas more price competitive with energy alternatives. However, this development is being muted by the realization, and potential acceleration, of the trends identified in 2009 that challenge FEI's core space and water heating market. New data continues to show, for instance, reduced capture rates and declining use rates for customers in the residential sector. On a whole, FEI's business risk (including regulatory risk) is best characterized as being similar – no lower, and perhaps somewhat higher- than what it was in 2009.

## 2. OVERVIEW OF BUSINESS RISK

In this section, the FortisBC Utilities ("FBCU") provide the following information in response to requirements identified in the MFR:

- Generic business risk categories, and generic risk factors within those categories, that can be applied to all utilities; and
- A summary ranking of the risk categories identified as they apply to FEI, together with a summary assessment of why FEI's overall risk profile remains similar to what it was in 2009.

### 2.1 – Generic Business Risk Categories and Factors

Item 2 in the MFR, quoted above, requires the FBCU to identify, in general terms, types of business risks. Business risks can be categorized in different ways. Ms. McShane has described in her evidence categories of utility business risk that can be applied to utilities generally, which are repeated below for ease of reference:

[4] In this appendix, the reference to electricity as an energy source in British Columbia mainly relate to BC Hydro, which deliveries nearly 95% of the electricity within the Province.

| | |
|---|---|
| **Market/Demand Risk** | • *Market demand risks relate to the size of the market for the utility's services and the ability of the utility to capture market share. Market demand risks reflect the demographics of the service area, including the diversity of the economy, economic growth potential, geography/weather, customer concentration, customer spending patterns, customer mix, and customer preferences.* |
| **Competitive Risk** | • *Competitive risk refers to the business risk arising from competition for customers and load due to the existence of alternatives to, or potential for substitutes for, the utility's services. Competitive risks would include a utility's cost structure; e.g., a high cost structure has the potential to lead to customer and load attrition and to the development of lower cost alternatives.* |
| **Supply Risk** | • *Supply risk relates to the physical availability of the commodities required to deliver service to end use customers. Supply risk includes exposure to supply interruption, and thus, for gas utilities, the degree of reliance on a single supply basin and/or pipeline and the availability of storage. For electric utilities, supply risk also reflects the diversity of supply sources, including owned generation and purchased power.* |
| **Operating Risk** | • *Operating risk encompasses the physical risks to the revenue generating capabilities of the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather.* |
| **Political Risk** | • *Political risk relates to the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal Rights.* |
| **Regulatory Risk** | • *Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in regulatory philosophy, government policies, including energy policy, and underlying fundamental business risk factors, e.g., the competitive environment.* |

Overlap among the business risk categories identified by Ms. McShane is expected. In recognition of the significant overlap and interdependency of Market/Demand Risk and Competitive Risk, the FBCU have broken down those two categories into four sub-categories for discussion purposes: Business Profile, Economic Conditions, Energy Price and Market Shifts.

In Table 1 below, the FBCU have identified generic risk factors applicable to each category or sub-category of business risk. Other risk factors and categorizations are possible. Some risk factors that the FBCU have identified could be captured under a different risk category.[5]

[5] For example, availability of energy supply could also be included as a risk factor under Energy Prices because the availability of supply of an energy form can impact its price.

**Table 1. Business Risk Categories and Risk Factors Addressed in this Appendix**

| Business Risk Category | Risk Factors |
|---|---|
| **Business Profile** | • Type of utility<br>• Energy product offering<br>• Size of utility<br>• Service area<br>• Customer profile |
| **Economic Conditions** | • GDP<br>• Housing starts<br>• Unemployment |
| **Energy Price** | • Commodity price<br>• Commodity price volatility<br>• Upfront and installation costs |
| **Market Shifts** | • New technology and energy forms<br>• Perception of energy<br>• Housing types<br>• Changes in energy use<br>• Changes in customer additions |
| **Energy Supply** | • Availability of supply<br>• Security of supply |
| **Operating** | • Infrastructure integrity<br>• Third party damages<br>• Unexpected events |
| **Political** | • Energy policies and legislation<br>• GHG emissions reductions<br>• Carbon tax<br>• Aboriginal rights |
| **Regulatory** | • Regulatory approvals<br>• Regulatory uncertainty and lag<br>• Deferral accounts<br>• Administrative penalties |

**Note:** Market shifts refers to factors, such as technological advancements, customers' perception of energy, and type and amount of housing types being built, which can ultimately impact the market share of the energy form.

## 2.2 – Summary Assessment of FEI's Business Risk

Table 2 addresses the MFR by ranking the business risk categories as they apply to FEI and by providing a summary assessment of whether the risk to FEI associated with particular risk factors is higher/lower/same as in 2009. The ranking of the risk categories provided below is essentially the same as in 2009, with regulatory risk being the greatest risk, followed by the risk categories most directly influencing throughput, and then other risk categories relating to operations and supply. While the FBCU have provided the information in response to the MFR, approaches involving ranking and/or tabulating itemized risk elements or categories should be approached with caution for the reasons articulated by Ms. McShane.

**Table 2. A Snapshot of FEI's Business Risk as Compared to 2009**

| Risk Category/Risk Factors | Risk Status (Since 2009) | Ranking of Risk |
|---|---|---|
| **Regulatory** | **Higher** | **1** |
| Regulatory Approvals | Same | |
| Regulatory Uncertainty and Lag | Higher | |
| Deferral Accounts | Same | |
| Administrative Penalties | Higher | |
| **Energy Price** | **Lower** | **2** |
| Commodity Price | Lower | |
| Commodity Price Volatility | Higher | |
| Upfront and Installation Costs | Same | |
| **Market Shifts** | **Higher** | **2** |
| New Technology and Energy Forms | Higher | |
| Perception of Energy | Same | |
| Housing Types | Higher | |
| Changes in Energy Use | Higher | |
| Changes in Customer Additions | Higher | |
| **Political** | **Same** | **2** |
| Energy Policies and Legislation | Same | |
| GHG Emissions Reductions | Same | |
| Carbon Tax | Same | |
| Aboriginal Rights | Same | |
| **Operating** | **Same** | **3** |
| Infrastructure Integrity | Same | |
| Third Party Damages | Same | |
| Unexpected Events | Same | |
| **Energy Supply** | **Lower** | **4** |
| Availability of Supply | Lower | |
| Security of Supply | Same | |

Although there has been an increase in natural gas supply potential and a decline in natural gas commodity prices, FEI continues to experience challenges similar to those identified in 2009. The factors identified in the table above are addressed briefly in the following bullets, but are the subject matter of the subsequent sections of this Appendix:

- FEI is dependent on regulatory approvals that determine its revenue requirements and cost of service recovery and approve investments. The Commission establishes the level of return that is allowed to be included in rates. If the allowed return is not reflective of the utility's cost of capital, or if rates are not set at a level that provides a reasonable opportunity to earn the allowed return, then this goes to one of the fundamental tenets of the definition of business risk. Further, the pace of change in the energy policy and environment has accelerated, the policy framework has become more complex, and the

Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment, and has added to the volume of regulatory process for FEI as compared to 2009.

- Commodity prices have declined in recent years, which has improved the price competitiveness of natural gas versus electricity. The decline in commodity prices has been offset partially by the carbon tax increases since 2008 as well as the continued difference in capital cost for natural gas equipment in comparison to electricity equipment. However, the more favourable price competitiveness of natural gas compared to electricity is being muted by other non-price factors, and has not slowed the challenging customer capture and use per customer trends identified in 2009.

- The market shift in energy demand caused by the continued introduction of new energy forms and technologies that produce energy closer to the point of consumption, along with rate of change in housing mix and customer perception of energy all represent challenges to retaining and attracting customers even in the current lower energy price environment.

- Climate change and energy policies were identified as new risk factors in 2009. The overall thrust of the climate change and energy policies remains similar to that articulated in 2009. With the passage of time, these policies have been implemented to a greater extent. FEI is now starting to see local governments mandate certain renewable energy solutions in new developments. Despite new policy developments in the Province in promoting the role of natural gas in the transportation sector, the role of natural gas in its traditional market of space and water heating continues to be challenged by the climate change and energy policy framework.

- Operating risk factors, particularly infrastructure integrity and capital investment requirements, remain relevant and are essentially the same as in 2009.

- The abundance of supply associated with the development of tight and shale gas resources has decreased FEI's risk associated with availability of supply, but the underlying infrastructure to move this natural gas to FEI's service territory (accessibility of supply) remains unchanged as compared to 2009. The development of several significant gas transmission infrastructure projects connecting BC deposits with Alberta and eastern markets in the coming years could alter the historical pricing relationship of BC supply in relation to Alberta production. This could have a negative impact to the price that consumers pay for natural gas in BC in the coming years.

Considered together, FEI business risk and regulatory risk is best characterized as being similar - no lower, and perhaps somewhat higher- than what it was in 2009. The risk categories identified in the "snapshot" above are discussed in detail in the remaining sections of this Appendix.

## 3. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. Discussed below is a high level overview of FEI's business profile. FEI remains a large natural gas distribution utility whose core business is to serving space and water heating load in the residential and commercial sectors. The core market is experiencing declining throughput levels and slow customer growth, which is central to FEI's overall business risk.

FEI is a company incorporated under the laws of the Province of British Columbia, operating since 1952. Its core business is the provision of natural gas.[6] FEI provides sales and transportation services to residential, commercial, and industrial customers in more than 100 communities in four service areas of the Lower Mainland, Inland and Columbia, currently serving approximately 835,000 customers throughout the Province.[7] FEI's distribution network serves approximately 85 percent of natural gas customers in BC and delivers more than 20 percent of the total energy consumed in the Province. Table 3 summarizes FEI's overall business profile.

**Table 3. FEI's Business Profile**

| | |
|---|---|
| **Type of Utility** | Local Distribution Company |
| **Energy Product Offering** | Natural gas, biomethane, propane |
| **Service Area** | Lower Mainland, Inland, Columbia and Revelstoke |
| **Rate Base*** | $ 2,717.1 (millions) |
| **Sales/Transportation Volumes*** | 168,496 (TJs) |
| **Number of Customers*** | 856,815 |
| **Customer Additions*** | 6,656 |
| **Customer Growth Rate*** | >1% |
| **Customer Profile by Demand*** | |
| Residential | 41% |
| Commercial | 28% |
| Industrial | 31% |
| **Customer Profile by Sales Revenue*** | |
| Residential | 60% |
| Commercial | 28% |
| Industrial | 12% |

*Based on 2012 Forecast, 2012-2013 RRA
Residential includes Rate Schedule 1
Commercial includes Rate Schedules 2, 3, 23
Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

[6] FEI also serves propane customers in Revelstoke. FEI has a new biomethane offering that is a notional mix of natural gas and 10% biomethane. FEI's Thermal Energy Service ("TES") offering is under review and should FEI receive an approval to provide TES, then TES will be offered other a separate class of service, different from that of natural gas class of service. Thermal energy, at times referred to as alternative energy service, is a variety of technologies that make use of renewable energy sources to provide space heating and cooling and hot water services. Renewable thermal energy typically relies on conventional energy, e.g. natural gas or electric, to provide back-up energy and to meet peak demand.

[7] With the implementation of the new Customer Care Enhancement Project ("CCE Project") on January 1, 2012, FEI changed its definition of a customer. As a result of this change in methodology, FEI has reduced its customer count by approximately 15,000 effective January 1, 2012.

Figure 1 depicts the customer profile by delivery margin revenue. The fact that the majority of the FEI's delivery margin revenue in 2011 was generated from residential customers (i.e. Rate Schedule 1) is significant because FEI faces its greatest challenges in the residential market.

**Figure 1. FEI Customer Profile by Delivery Margin Revenue (2011)**

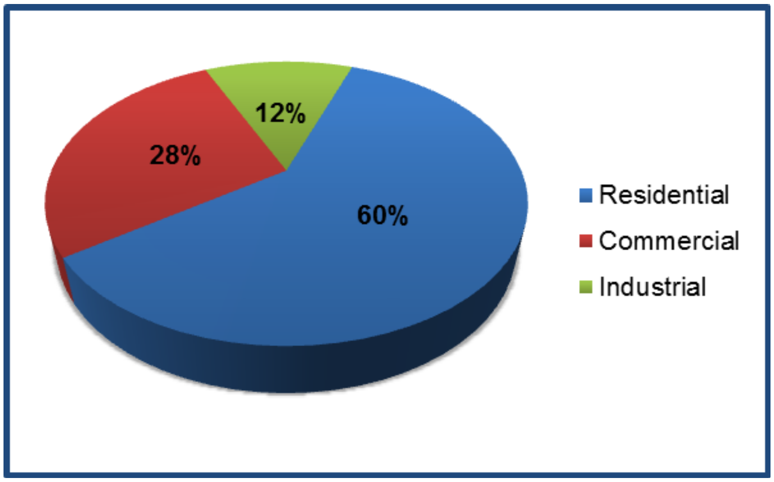
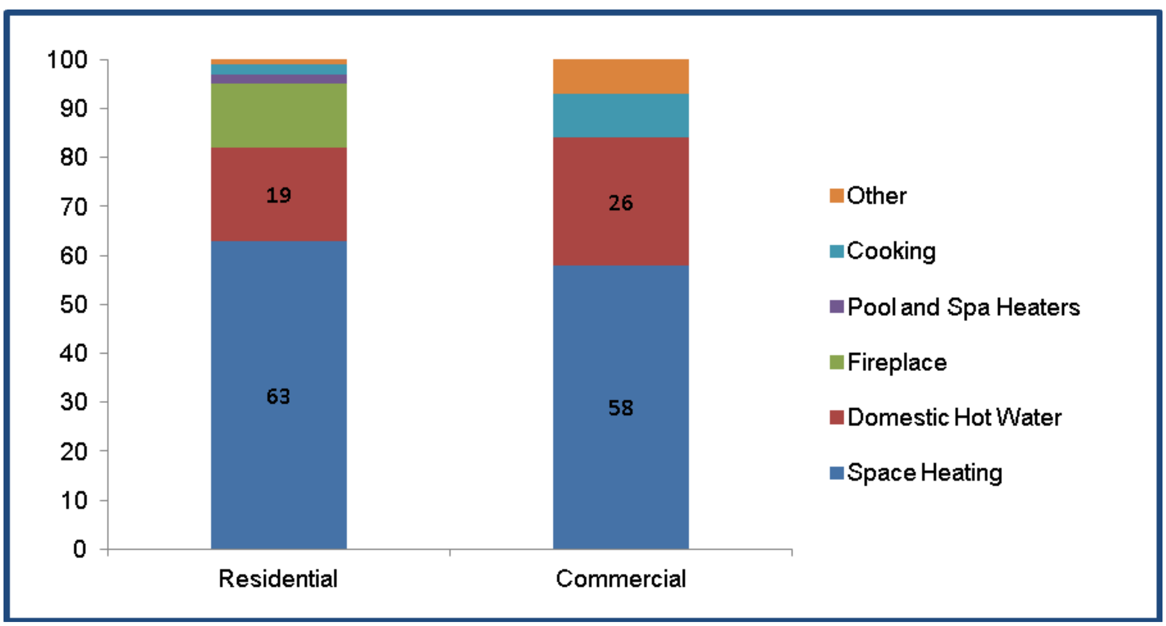



Figure 2 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 80 percent of the energy consumption.

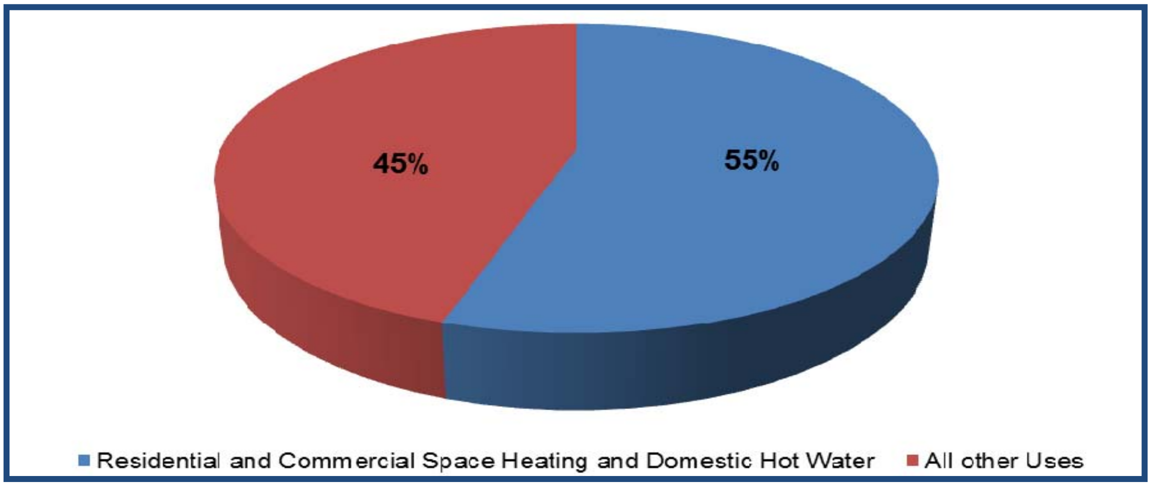
**Figure 2. FEI Residential and Commercial Consumption by End Use (2010)**




**Source:** 2010 CPR study

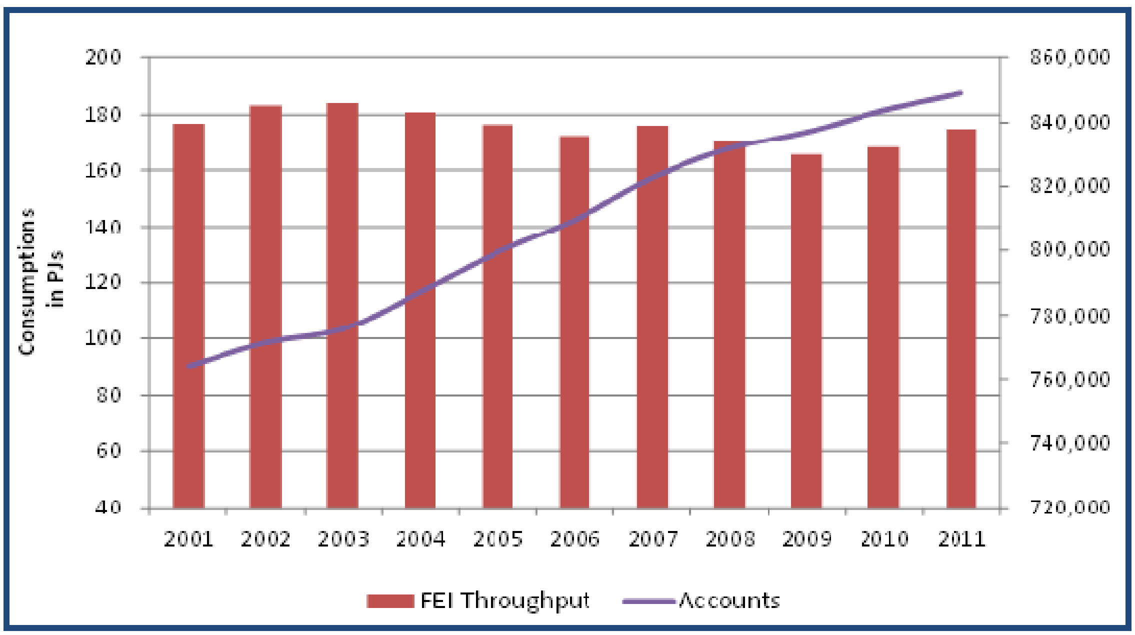
Thus, the space and water heating market in residential and commercial applications is FEI's largest market for natural gas, as shown in Figure 3 below.

**Figure 3. FEI Total Consumption by End Use (2011)**




As demonstrated in Figure 4, despite adding substantial residential customers to its customer base in the past ten years, FEI has generally experienced a downward trend through 2009 in total throughput as compared to the 2002-2004 timeframe. In 2010-2011, FEI has experienced a modest increase in throughput in the industrial sector as some industrial customers have fuel switched towards natural gas to take advantage of the lower natural gas prices compared to their alternatives. Whether this uptick in the industrial sector will be maintained in the long-term is dependent on the competitiveness of natural gas to alternatives for each industrial customer. Additionally, industrial volume decreases since 2001 are due to the number of industrial customers that have been lost since 2001, so it is questionable whether the industrial loads can be relied upon to return to 2001 levels in the absence of new customers.

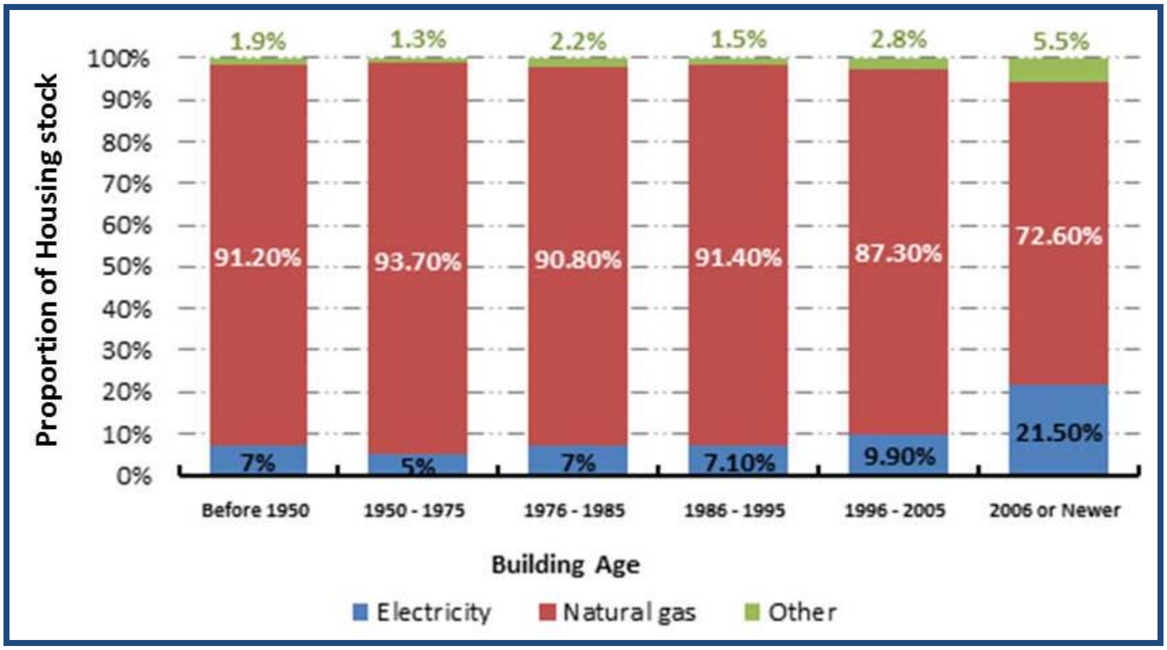
**Figure 4. FEI's Total Throughput (Normalized Demand vs. Customer Accounts)**




**Note:** This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

The use of natural gas as a main space heating fuel is diminishing due to the rise in use of electricity as a main heating fuel. According to the 2010 Residential New Home Survey ("RNHS"), new homes with gas service are less likely to use natural gas as a main space heating fuel and more likely to use electricity compared to the stock of gas homes built prior to 2006. Figure 5 below illustrates the main space heating fuel trend by dwelling age.

**Figure 5. Natural Gas Use for Residential Space Heating**




**Source:** 2010 Residential New Home Survey

The above trend regarding use for space heating in housing stock of a particular age is significant because the share of natural gas heated homes with respect to homes built since 2005 has eroded in light of increasing use of other energy forms, primarily electricity. As demonstrated in Table 4, this trend is consistent in other jurisdictions in Canada, but BC has experienced the largest decline from 2005 to 2009.

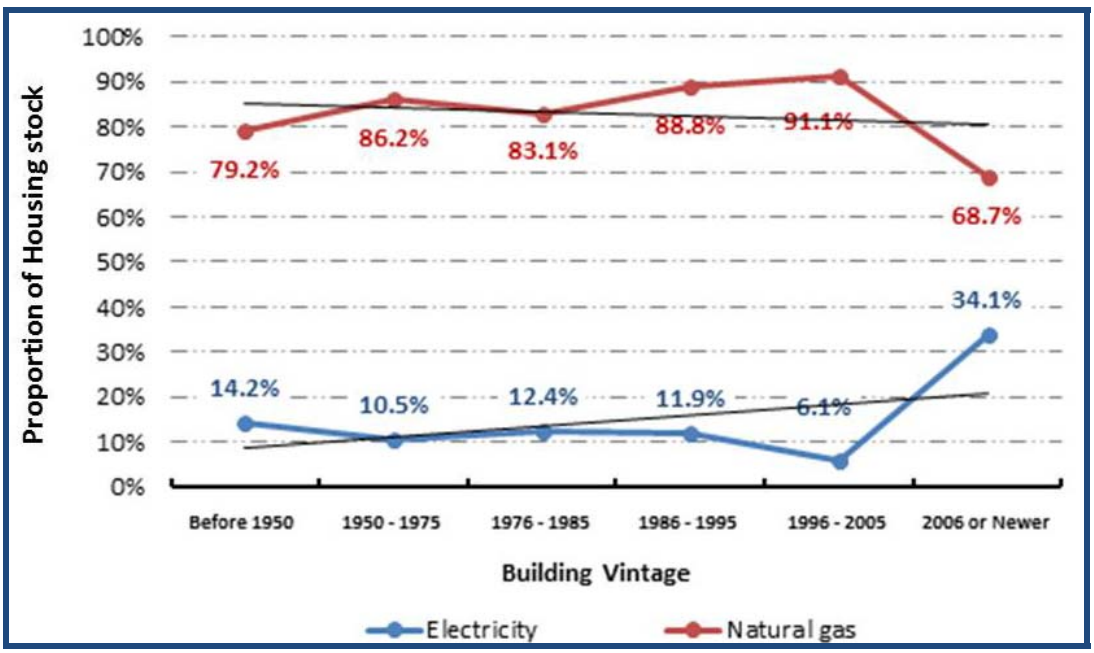
**Table 4. BC Market Share of Natural Gas vs. Electricity in Residential Space Heating as Compared to Other Jurisdictions**

| | 2005 | 2006 | 2007 | 2008 | 2009 | % Change 2005-2009 |
|---|---|---|---|---|---|---|
| **British Columbia** | | | | | | |
| Electricity | 26.7 | 27.2 | 27.0 | 30.7 | 30.6 | 14.6 |
| Natural Gas | 59.4 | 59.2 | 58.4 | 55.0 | 55.7 | -6.2 |
| **Alberta** | | | | | | |
| Electricity | 4.2 | 4.6 | 4.7 | 5.0 | 5.6 | 33.3 |
| Natural Gas | 94.5 | 94.1 | 94.2 | 93.8 | 93.2 | -1.59 |
| **Ontario** | | | | | | |
| Electricity | 14.7 | 13.4 | 13.1 | 14.5 | 15.4 | 4.76 |
| Natural Gas | 72.1 | 72.2 | 73.9 | 73.4 | 72.3 | 0.28 |
| **Quebec** | | | | | | |
| Electricity | 49.4 | 51.7 | 52.3 | 54.5 | 56.8 | 14.98 |
| Natural Gas | 8.9 | 8.2 | 7.8 | 7.9 | 8.4 | -5.62 |

**Source:** Natural Resources Canada
**Note:** Data is not yet available for 2010 and 2011.

The FBCU sees the same trend occurring for Domestic Water Heating ("DWH"), which constitutes the second largest share of natural gas for residential customers (accounting for 19% of total residential natural gas use). Penetration rates of domestic water heaters in 2008 were high. According to the 2010 RNHS, new homes with gas service are less likely to use natural gas fired DWHs and more likely to use electricity compared to the stock of gas homes built prior to 2006. Figure 6 below illustrates the trend in DWH fuel by dwelling age.

**Figure 6. Trend in Residential Domestic Water Heating Fuel by Dwelling Vintage**




**Note:** Numbers not additive because some homes may have more than one DWH fuel

Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units, which is a result of factors such as the government's energy policies related to GHG emissions reduction.

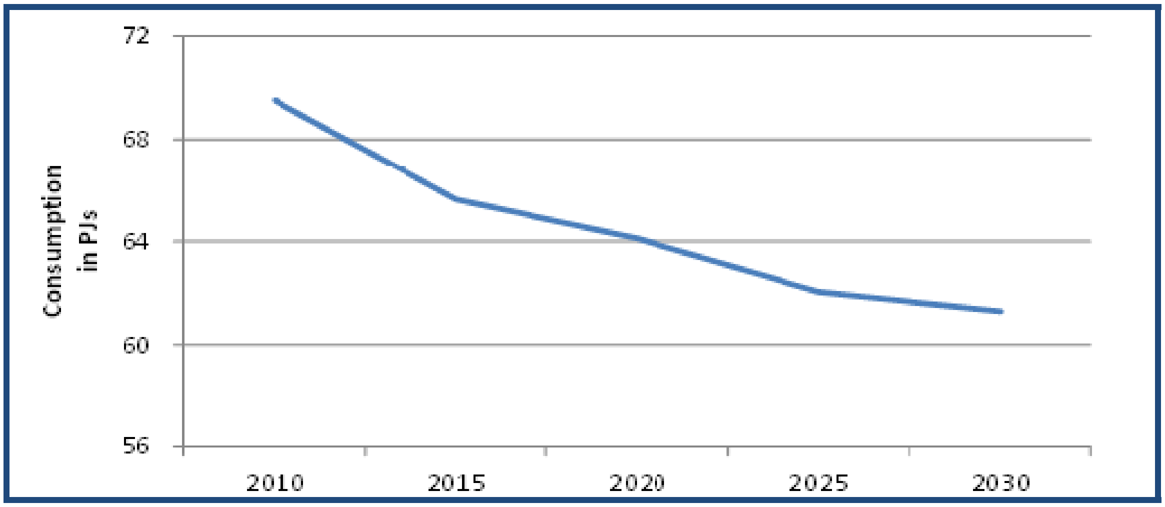
As an example, upcoming federal DWH efficiency regulations for natural gas water heaters will impact the market, further reduce natural gas consumption, and impact use per account over time.[8] In BC, the minimum efficiency standard of the most common natural gas storage-type water heaters is 0.62 Energy Factor ("EF"). The federal government is proposing 0.67 EF as the minimum efficiency for 2016 resulting in about 14% energy savings per unit installed. Because these tanks require an electric plug for the electronic ignition and flue dampers, a small portion of customers may upgrade their electrical service and switch to an electric tank. Furthermore, the federal government is proposing 0.80 EF as the minimum efficiency standard by 2020. This will require the adoption of new technologies such as tankless and hybrid systems and condensing storage tanks. These technologies result in about 25-35% energy savings per unit installed. The new technologies are more costly than the status quo which adds additional cost barrier that may be expected to encourage switching to electric water heating, and contribute to the trend shown in Figure 6 above.

Further, if customers are not installing gas furnaces, they are much less likely to install a gas water heater. As such, the relative cost disadvantage of installing a gas water heater as opposed to an electric water heater contributed to the decline in use of natural gas. Additionally, because a natural gas water heater requires venting, the loss of interior space to accommodate venting factors in the decision regarding whether or not to install the already more expensive natural gas units.

As space heating and domestic hot water heating together account for over 80% of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth. Figure 7 shows the most likely scenario for throughput levels in the residential sector in the years to come.

[8] MEMPR Enforcement Bulletin 09-05. BC Efficiency Act Standards: Gas and Propane Fired Water Heaters.

**Figure 7. Outlook of Residential Throughput Levels**




**Source:** 2010 Conservation Potential Review – Residential Sector- Most Likely Scenario

FEI has, in recent years, responded to the changing energy environment in BC and declining throughput in its core business by undertaking new initiatives. One of those initiatives, Natural Gas for Transportation ("NGT"), has been identified as a potential new source of load outside of FEI's core market. Table 5 provides an estimate of the additional volumes forecast to be added to the system as a result of Greenhouse Gas Reduction (Clean Energy) Regulation incentive funding.

**Table 5. FEI's NGT Demand (2012-2017)**

| CNG Vehicle Demand (GJ) | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| Vocational trucks | 22,000 | 85,063 | 138,015 | 261,824 | 384,901 | 551,568 |
| Transit/School Buses | 6,000 | 51,000 | 81,075 | 118,112 | 165,171 | 227,671 |
| Total CNG Vehicle Demand | 28,000 | 136,063 | 219,090 | 379,936 | 550,072 | 779,239 |
| | | | | | | |
| **LNG Vehicle Demand (GJ)** | | | | | | |
| Class 8 tractors | 150,000 | 321,875 | 598,065 | 836,161 | 1,182,315 | 1,703,148 |
| Marine Vessels + Other Applications | 0 | 0 | 100,000 | 200,000 | 300,000 | 400,000 |
| Total LNG Vehicle Demand | 150,000 | 321,875 | 698,065 | 1,036,161 | 1,482,315 | 2,103,148 |
| | | | | | | |
| **Total NGT Demand (GJ)** | **178,000** | **457,938** | **917,156** | **1,416,097** | **2,032,387** | **2,882,387** |

NGT volumes, should they materialize, will be a favourable development for customers in terms of representing a revenue stream. However, they do not materially affect FEI's overall risk profile. FEI's current core business remains natural gas distribution for space and water heating and will remain FEI's core business for the foreseeable future even with additions of NGT load that may occur. Attracting and retaining customers in the traditional heating markets remains a critical undertaking, and a key challenge, for FEI.

FORTIS BC™

## 4. ECONOMIC CONDITIONS

Economic and financial conditions can, in addition to affecting utility access to capital in the manner discussed by Mr. Engen and Ms. McShane, impact the ability of utilities like FEI to attach and retain customers or maintain throughput levels.

Table 6 summarizes the changes of leading economic indicators for four jurisdictions across Canada from 2005 to 2011(actual) and for 2012 to 2013 (forecast). Housing starts, in particular, is an important variable in determining residential customer additions.

**Table 6. Economic Indicators for Four Jurisdictions in Canada (2006 to 2013)**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|
| **British Columbia** | | | | | | | | |
| Real GDP (% Change) | 4.1 | 3.0 | 0.7 | -2.0 | 3.2 | 2.6 | 2.3 | 2.6 |
| Unemployment (%) | 4.8 | 4.3 | 4.6 | 7.7 | 7.6 | 7.5 | 7.0 | 6.8 |
| Housing Starts (% Change) | 5.1 | 7.6 | -12.4 | -53.2 | 65.2 | -1.1 | 1.7 | 0.5 |
| **Alberta** | | | | | | | | |
| Real GDP (% Change) | 5.8 | 1.7 | 1.4 | -4.6 | 3.4 | 4.1 | 4.9 | 3.3 |
| Unemployment (%) | 3.4 | 3.9 | 3.1 | 6.6 | 6.5 | 5.5 | 4.8 | 4.2 |
| Housing Starts (% Change) | 19.9 | -1.3 | -39.7 | -30.9 | 34.1 | -5.4 | 18.7 | 0.1 |
| **Ontario** | | | | | | | | |
| Real GDP (% Change) | 2.4 | 2.0 | -0.6 | -3.2 | 3.1 | 2.0 | 2.2 | 2.3 |
| Unemployment (%) | 6.3 | 6.4 | 6.5 | 9.0 | 8.7 | 7.8 | 7.5 | 7.2 |
| Housing Starts (% Change) | -6.8 | -7.2 | 10.2 | -33.2 | 20.7 | 11.6 | 8.1 | -6.1 |
| **Quebec** | | | | | | | | |
| Real GDP (% Change) | 1.8 | 2.1 | 1.3 | -0.6 | 2.5 | 1.7 | 1.7 | 2.0 |
| Unemployment (%) | 8.1 | 7.2 | 7.2 | 8.5 | 7.9 | 7.7 | 7.9 | 7.7 |
| Housing Starts (% Change) | -6.0 | 1.4 | -1.3 | -8.9 | 17.5 | -6.3 | -7.4 | 6.8 |

**Source:** various sources (forecasts are calculated based on average)

The global recovery from the 2008-2009 financial crisis remains fragile and risks to the global financial system remain high. Economic and financial conditions external to both Canada and BC (i.e. the European sovereign debt crisis) have the potential to impact Canada's and BC's economic outlooks. As seen in the 2012 and 2013 forecasts in Table 6, BC is expected to face economic challenges with a continued period of low economic growth, higher unemployment rates, and lower housing starts than experienced prior to the crisis. Lower projected economic growth and lower housing starts can be expected to make it more difficult for FEI to add new customers and throughput. Over the longer-term, growth in GDP and housing starts are expected to be more modest than they have been historically.[9]

[9] The Conference Board of Canada, Provincial Outlook 2012, April 2012 projects real GDP and housing starts growth in BC from 2011 to 2035 at 2.0% and 0.1% respectively. The corresponding actual growth rates in the 25 years period ending 2007 (pre-crisis) were 3.0% and 0.8% respectively.

FORTIS BC™

## 5. ENERGY PRICE RISK

In this section, the FBCU address business risk associated with energy prices. Energy prices impact utility business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[10] There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity.[11] They include.

- natural gas commodity cost relative to electricity,
- natural gas price volatility, and
- relative installation costs of gas appliances compared to electric appliances.[12]

While energy price remains a driver of business risk, and commodity prices have fallen, recent experience suggests that other non-price considerations such as GHG emissions type of housing mix, customer perceptions and government policy (discussed in subsequent sections) are taking on greater importance in the decisions of energy consumers.

### 5.1 – Commodity Price

This section addresses the commodity price of natural gas versus electricity and how it affects FEI's competitive position. While natural gas commodity prices are set by the market, electricity prices are heavily influenced by BC Hydro's low embedded costs, making it more difficult for FEI to compete against electricity than gas utilities in some other provinces. Natural gas competitiveness in BC is further challenged by application of the BC carbon tax. Nevertheless, recent low natural gas prices, although partially offset due to increases to the carbon tax, has caused FEI to assess this particular risk factor as "lower" compared to 2009.

#### *Natural Gas Commodity Prices*

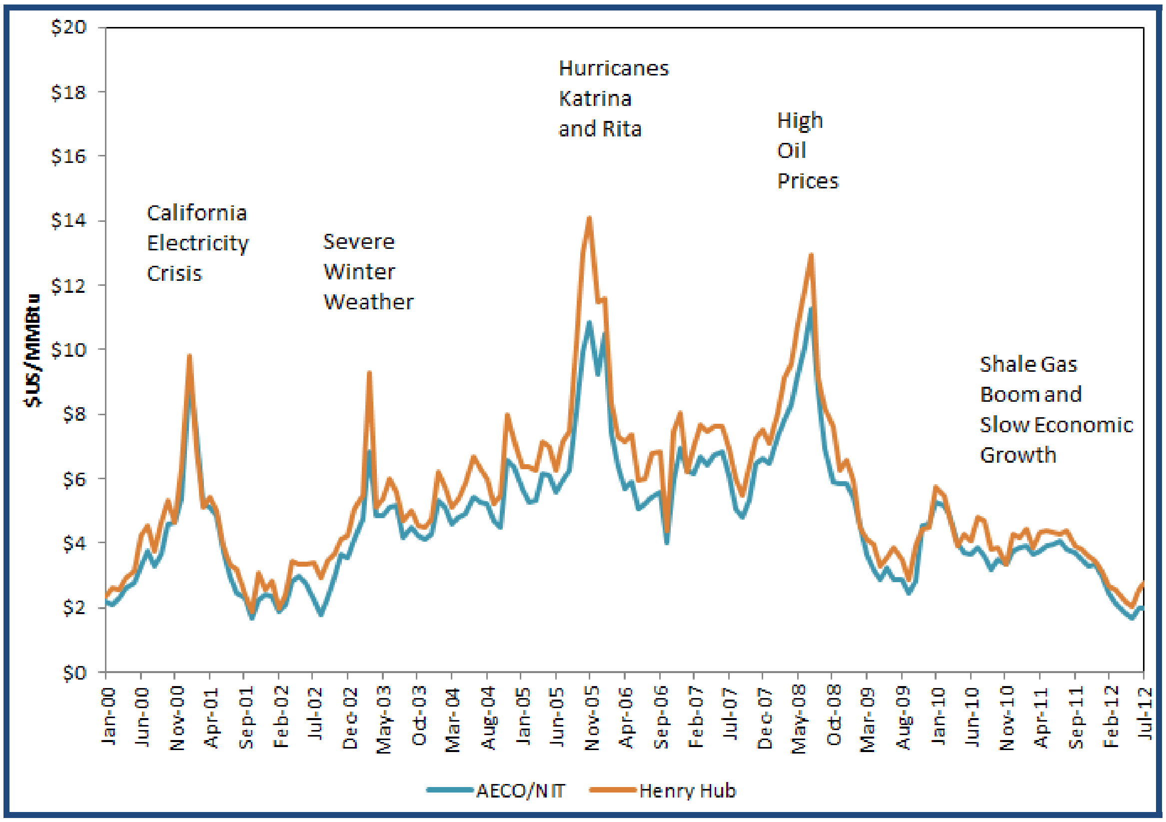
In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing the gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

[10] In this document, the references to electricity as an energy source in British Columbia mainly relate to BC Hydro, which delivers nearly 95 percent of electricity within the Province.
[11] This was recognized by the Commission in its 2009 ROE and Capital Structure Decision, page 36, where the Commission stated: *"…natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent".*
[12] Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units.

The North American natural gas market has undergone significant changes during the past few years in terms of supply, demand, and pricing. Advances in technology and significant cost reductions related to unconventional gas development, in particular shale gas, has created an abundance of supply in North America. In terms of demand, the recent global recession has reduced the pace of growth for gas demand in North America, especially from the industrial segment. The combination of these factors has created an over-supplied market, resulting in a low price environment for natural gas as compared to 2009.

Figure 8 illustrates the influence that different economic, market and weather events have had on market prices over the last decade.

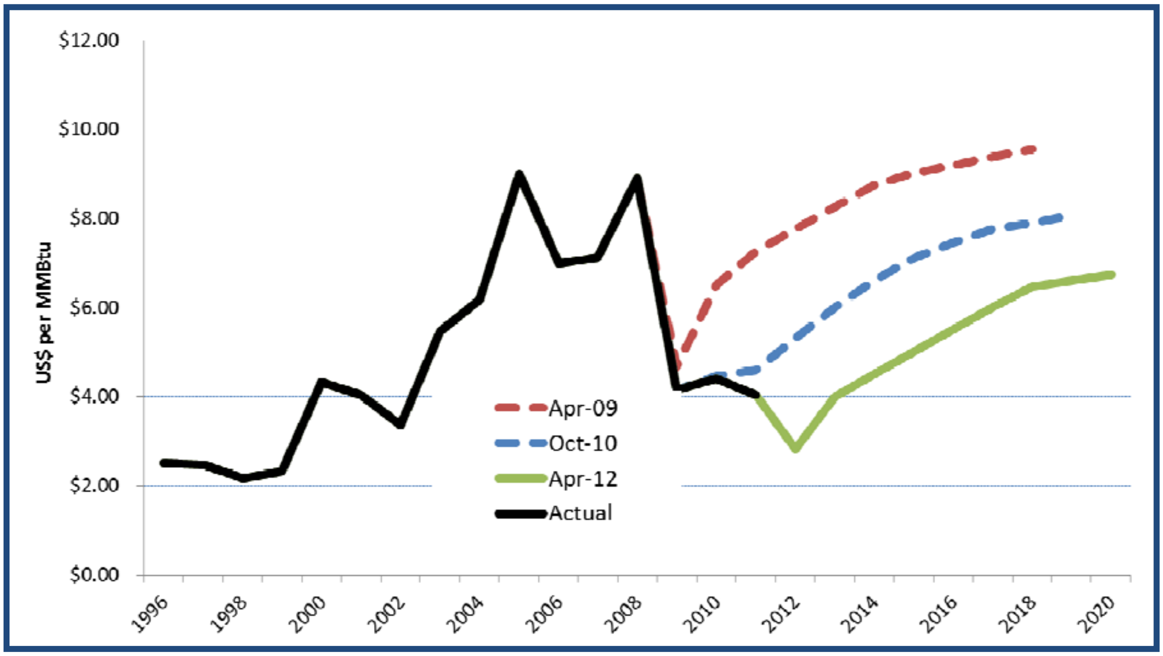
**Figure 8. Factors that Impact Actual Natural Gas Commodity Prices**




**Source**: GLJ Petroleum Consultants, National Energy Board, Gas Alberta, CME Group
http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/prcng/cndnnrgprcngtrndfct2011/cndnnrgprcngtrndfct-eng.html
http://www.gasalberta.com/pricing-market.htm; www.cmegroup.com

Although it is generally expected that the current low price levels are not sustainable, the size and scope of the shale gas supply resources in North America has resulted in a much more favourable supply outlook. As a result, the current long-term market view of natural gas prices reflect a significant shift downwards compared to the outlook in 2009. This shift is illustrated in Figure 9 below.

**Figure 9. Comparison of Natural Gas Price Forecasts**




Lower commodity prices for natural gas have been offset partially by increases in BC's carbon tax on natural gas. The carbon tax has increased from approximately $0.50/GJ in 2008 to $1.50/GJ in 2012. At present, there is uncertainty with respect to the future price of the carbon tax as the government has stated that the tax is under review[13] (see section 9.3 for further discussion on the carbon tax).

While North American natural gas prices are at their lowest levels in many years due to surplus supply, both producers and end use markets will adapt their consumption and production patterns so that, over time, supply and demand will ultimately rebalance. As the supply and demand balance tightens, natural gas commodity prices are likely to rise from their current levels.

The BCUC recognized that rebalancing of supply and demand factors is likely to have upward pressure on commodity prices in its recent Decision related to FEI's application for approval of its proposed Price Risk Management Plan:

> *With the current price of gas at levels which have not been seen in years, the Panel acknowledges that the potential for downward movement of the price of natural gas is limited and the potential for upward movement is greater. However, we also note that in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years. This is not to say that the risk of more dramatic increases in natural gas prices has been eliminated. On the*

[13] BC Ministry of Finance. Carbon Tax Review, and Carbon Tax Overview. http://www.fin.gov.bc.ca/tbs/tp/climate/carbon_tax.htm

> *contrary, factors such as the potential for growth in LNG exports and the possibility of a more dramatic economic recovery leading to increased consumption are just two of the myriad of events which could affect future natural gas prices*."[14]

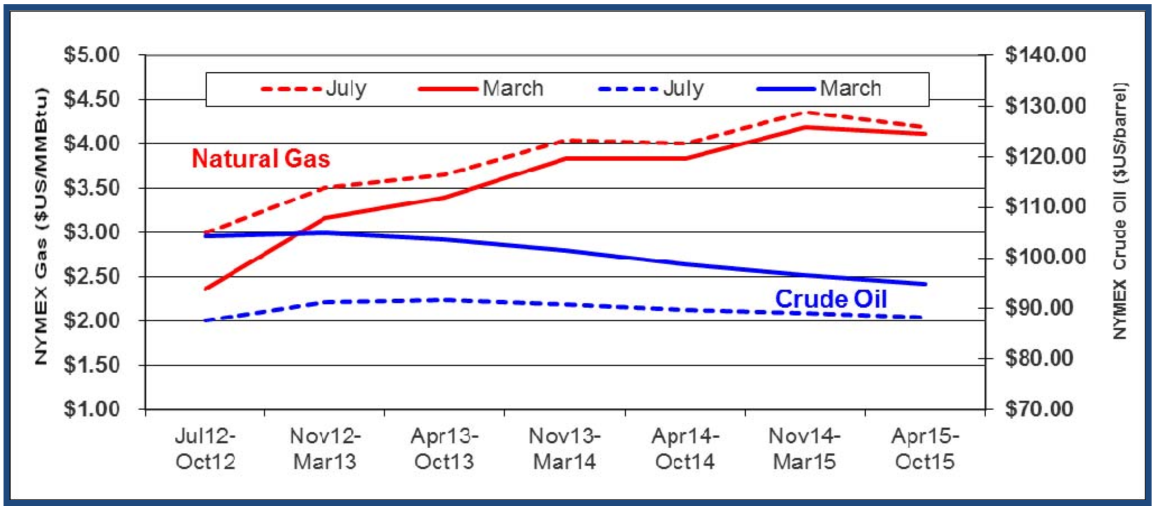
Changes in the supply and demand balance are already occurring and there is an expectation that natural gas commodity prices will increase from their current levels. North American dry gas production growth is expected to slow in the next two years as natural gas producers curtail dry gas production in response to low gas prices. If natural gas prices remain below sustainable cost levels for producers, a supply response will lead to higher prices, all else being equal. On the other hand, higher crude oil and liquids prices have provided the incentive for natural gas producers to shift from dry gas drilling to liquids-rich and oil plays. Although there will be some associated gas production from liquids production, this will not fully offset the expected declines in dry gas production. In addition, some recent shut-ins by major gas producers to their production in response to low natural gas prices will also contribute to a tightening of the supply and demand balance of the natural gas marketplace and all else equal put upward pressure on gas prices in the future.

In terms of demand, low natural gas prices have created opportunities for greater use of natural gas. As a marketplace as a whole, higher natural gas demand is expected to come from several key areas, including a shift from coal to natural gas for power generation, and LNG exports from the US and Canada.

Evidence of this shift in supply and demand factors has been witnessed over recent months. While producers have shifted drilling away from natural gas, North American overall gas production has remained constant in 2012 relative to 2011, due to increased initial well productivity from the shale developments. Meanwhile, overall gas demand has increased driven primarily by a significant shift to gas from coal for power generation. As a result, between end of March 2012 and the end of July 2012, NYMEX spot prices have increased from below $2.00 to over $3.00 US/MMBtu. The tightening of supply and demand has also mitigated fears over short term storage congestion resulting in a lift in the forward market curve as shown in Figure 10 below.

[14] BCUC Order No. G-120-11, July 19, 2011, Appendix A, page 25.

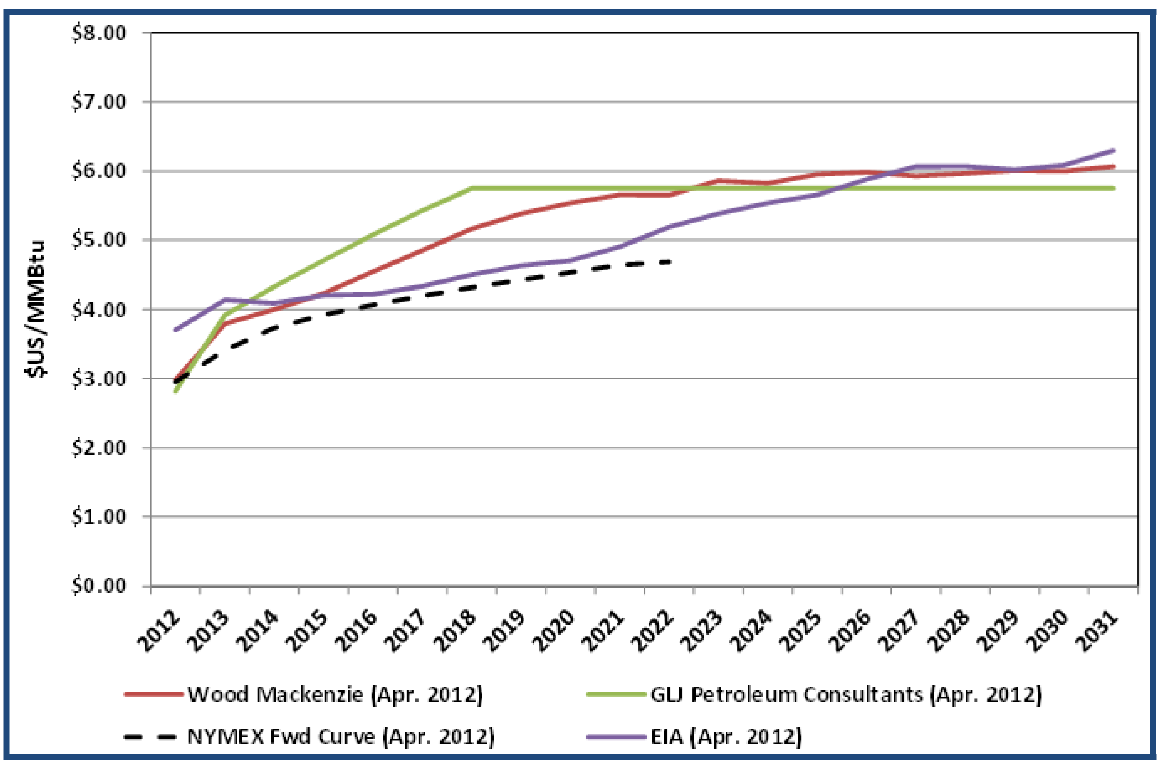
**Figure 10. Changes in NYMEX Forward Gas Prices**




**Source Data**: NYMEX Forward Prices as of 27 July 2012 and 29 March 2012

Figure 11 compares the current NYMEX forward curve and various long-term real price forecasts for natural gas from industry experts. These forecasts show gas price increasing from current low levels towards $4.50 to $5.00 US/MMBTU by 2020 and approximately $6 US/MMBtu by 2030 (constant 2012 dollars), adding to the competitive pressure on natural gas as an alternative to electricity in heating and cooling applications.

**Figure 11. Natural Gas Price Forecasts for NYMEX (Henry Hub)**

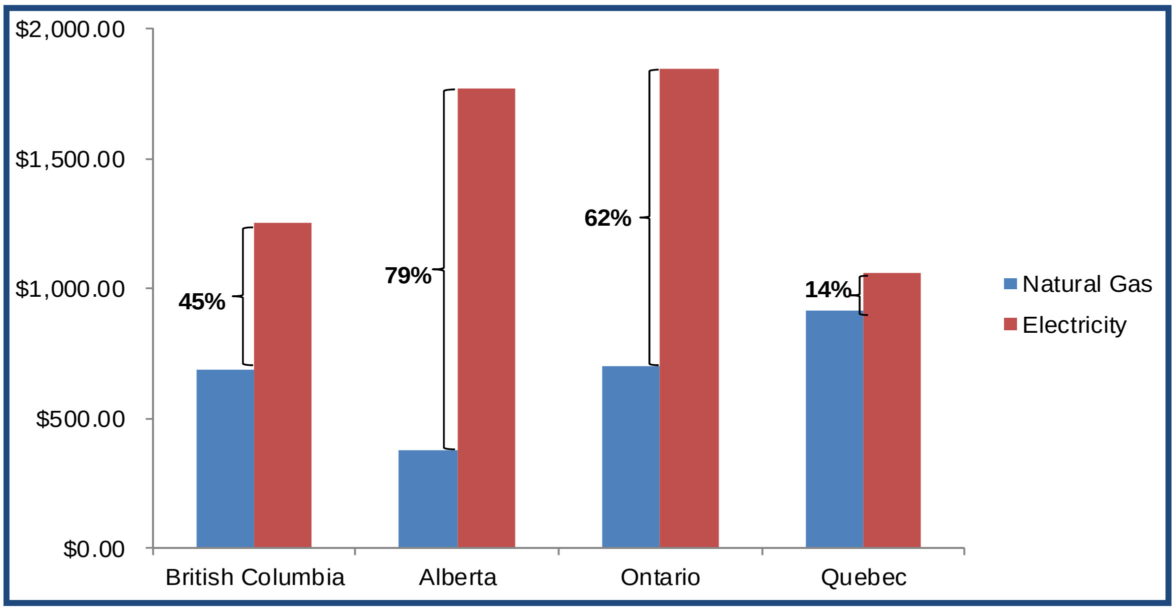


## Electricity Prices

The operating costs advantage of natural gas over electricity has historically been lower in BC relative to some other jurisdictions, in particular Alberta and Ontario, because of BC Hydro's low electricity prices. Lower electricity prices in BC relative to other provinces is expected to continue into the future, representing a competitive challenge for FEI in maintaining and attracting customers that does not exist to the same extent in other provinces.

Figure 12 shows the extent to which residential electricity rates differ from province to province. It also demonstrates how the magnitude of the cost difference between electricity and natural gas differs among these jurisdictions. Natural gas has the lowest operating cost advantage over electricity in Quebec and BC.

**Figure 12. Residential Operating Cost Differences between Natural Gas and Electricity**




**Notes:**

- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimate bills calculated based on annual use rate of 60 GJs
- All rates are exclusive of applicable franchise fees and taxes (with the exception of carbon tax)
- Calculations based on rates applicable as at April 1, 2012
- The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use

The relatively low price of electricity in BC compared to Alberta and Ontario is largely reflective of Heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the Province's hydro generation facilities. BC Hydro's current rates also do not reflect the full costs of providing electricity in BC, with significant deficiencies having accumulated in deferral accounts.[15] Although BC Hydro must invest in new generation facilities and transmission infrastructure to meet growing demand,[16] it is uncertain how the cost of the future investment will impact BC Hydro rates given the government's policy of maintaining low electric prices in the province. The BC Government has recently adjusted BC Hydro rates increases down from what had been request by the utility, which in turn impacts natural gas competitiveness against electricity.[17]

Electricity rates in Quebec, which are also low compared to Alberta and Ontario, are also significantly influenced by relatively low embedded costs. In Alberta and Ontario, by contrast, electricity prices are based on market forces. In Alberta, electricity is generated mainly by the combustion of coal, which is more expensive than the historical cost hydro generation in British Columbia. Ontario has the most diverse electricity supply mix in Canada, with nuclear being the main source of electricity generation, followed by hydro and then natural gas. Despite the diversity of supply in Ontario, it has higher electricity costs than Quebec and BC.

The narrower operating cost advantage of natural gas over electricity in BC represents a greater challenge for FEI than exists for natural gas utilities in other jurisdictions like Alberta and Ontario. The relatively narrow operating cost advantage makes it more difficult to overcome obstacles to natural gas adoption such as greater price volatility and higher capital and installation costs, which are discussed next.

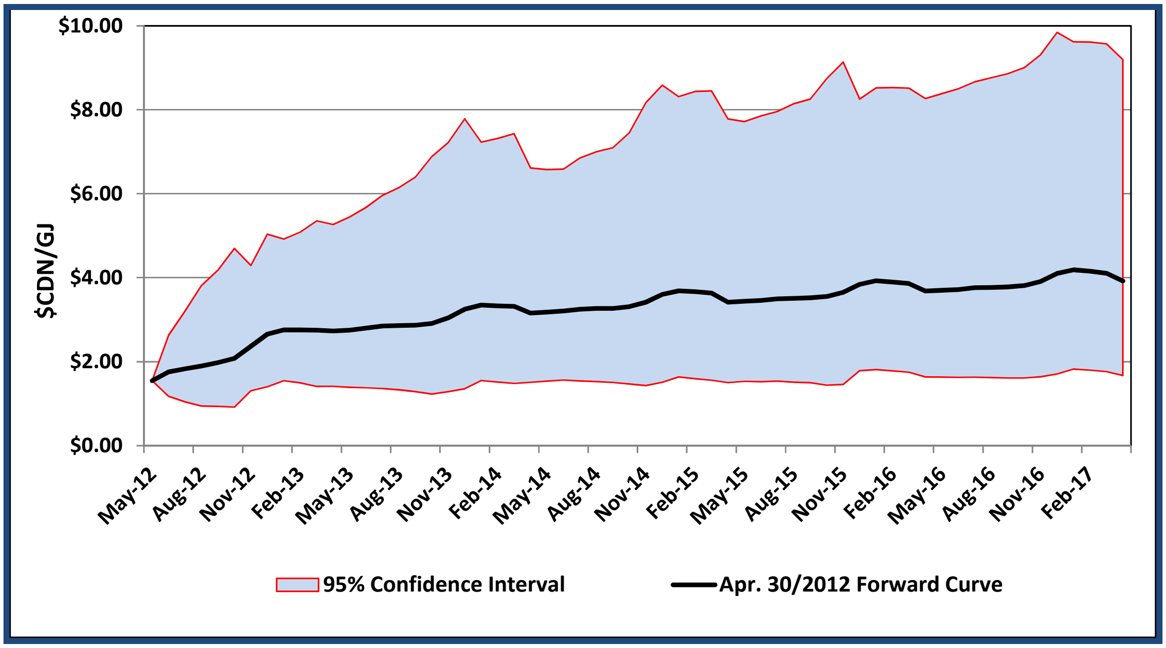
## 5.2 – Commodity Price Volatility

Natural gas prices are more volatile than electricity prices in BC due to the fact that natural gas is market-based, while electricity is primarily cost-based. Price volatility is an impediment to attracting and retaining natural gas customers because it can have a negative impact on natural gas rates and can taint consumers' view of using natural gas as a fuel. Greater price volatility can be perceived to lead to higher prices and rates in the future.

Figure 13 shows the forward AECO/NIT price range using implied volatility, which is derived from the prices for options for AECO/NIT using prices as of April 30, 2012. As the figure illustrates, current implied volatility in the market indicates that AECO/NIT prices for November 2014, for instance, with a 95% confidence interval, will be between about $9 CDN/GJ and $1.50 CDN/GJ.

[15] Clean Energy BC. Deferral and Regulatory Account Backgrounder. http://www.cleanenergybc.org/media/Deferral_and_Regulatory_Account_BACKGROUNDER_110602_DA_FINAL.pdf
[16] BC Hydro Draft Integrated Resource Plan 2012, A Plan to Meet BC's Future Electricity Needs
[17] BC Ministry of Energy and Mines, News Release. http://www2.news.gov.bc.ca/news_releases_2009-2013/2012ENER0063-000720.htm

**Figure 13. AECO/NIT Forward Curve and Implied Volatility**




Similarly, regional market gas prices continue to be volatile, particularly at the Sumas market hub. Prices at the Sumas supply hub often disconnect from other regional prices, such as Station 2 and AECO/NIT, in times of cold weather and high demand due to lack of deliverability capacity and restricted infrastructure at Sumas. Constrained regional infrastructure leads to higher prices since utilities in the region bid up the price to attract the supply to serve their service regions.

Regional infrastructure additions can help mitigate some of the risk of regional price disconnections; however, these additions are infrequent and require a long time to plan, receive approval and construct. The Southern Crossing Pipeline and the Mt. Hayes LNG storage facility are examples of regional infrastructure that were approved and subsequently constructed to meet growing regional demand and have helped to reduce some of the regional constraints. However, further infrastructure developments are needed to meet the pace of demand growth in the Pacific Northwest region, which relies on natural gas infrastructure to meet the growing demand for electricity that is generated from natural gas.

Price risk management strategies can also help to mitigate regional price disconnections and reduce price volatility in the short-term. Although since the recent Price Risk Management Decision (Order No. G-120-11), the majority of FEI's hedging activities have been suspended, FEI still has approval to use Sumas/AECO price swap instruments to help manage regional price disconnects at Sumas. However, many of past risk mitigation strategies to reduce volatility are no longer in place and therefore greater portion of FEI's supply portfolio is subject to market price fluctuations. As a result, we have assessed the risk associated with price volatility to be higher than in 2009.

## 5.3 – Upfront and Installation Costs

Although the price competitiveness of natural gas versus electricity in BC has improved on an operating cost basis, natural gas direct use applications (space and water heating) generally require higher capital and installation costs than those for electricity. FEI expects this capital cost difference between natural gas and electricity to continue into the future. The higher upfront capital costs of natural gas end-use applications erodes natural gas' operating cost advantage as compared to electricity and can influence energy choices.

Builders and developers are the primary decision makers as to what energy source and equipment are used in new construction. As builders and developers do not pay the operating costs, they tend to be more influenced by capital costs alone. A builder or developer also strives to maximize the useable square footage available from the development to maximize their return on investment. Capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The upfront capital cost difference for installing natural gas equipment has been identified by the American Gas Association as the "…primary impediment to natural gas use in residential and commercial buildings if service can be made available."[18]

Table 7 demonstrates as an example the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank for new construction. The difference in upfront capital costs between gas and electric means that over the life of the appliance the operating cost advantage between natural gas and electricity would have to be at least $9.93/GJ for space heating and $5.67/GJ for water heating for the installation of the natural gas rather the electric equipment to be economic for the a consumer.

**Table 7. Capital Costs for Space and Water Heating**

| | Space Heating | Water Heating |
|---|---|---|
| **Capital costs for natural gas** | $9,000 | $2,000 |
| **Capital costs for electric** | $4,320 | $1,023 |
| **Difference in upfront capital costs** | $4,680 | $977 |
| | | |
| **Operating costs per year** | $446.68 | $113.32 |
| **Maintenance costs per year** | $50.00 | $0.00 |
| **Total costs per year to pay off difference in capital cost** | $496.68 | $113.32 |
| | | |
| **Energy consumption (GJs)** | 50 | 20 |
| | | |
| **Difference in costs between natural gas and electricity over measurable life ($/GJ)** | **$9.93** | **$5.67** |

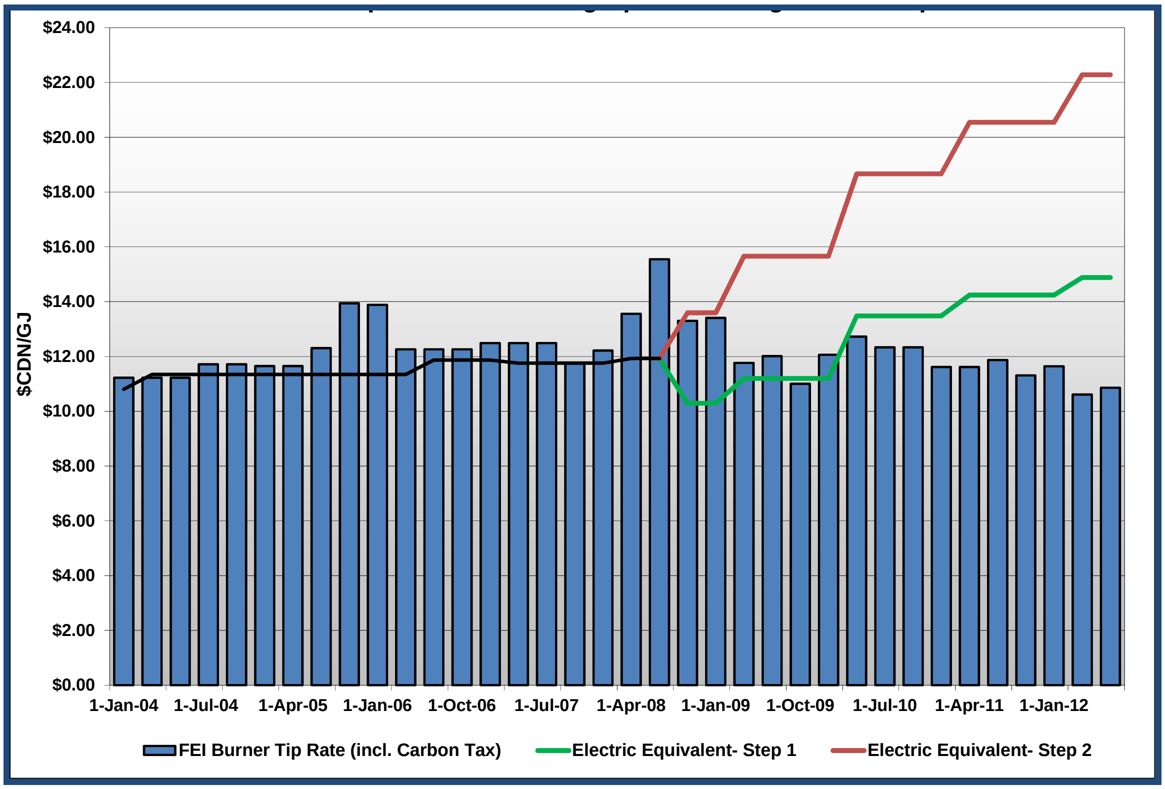
**Note:** assumptions based on new construction of a home in Lower Mainland (3000 square feet in size), interest rate of 6% and measurable life of 17 years for space heating furnace and 13 years for hot water tank.

[18] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges. page 32.

In this example, assumptions were based on a single family dwelling (3000 square feet in size). When considering smaller multi-family dwellings ("MFD"), such as townhouses and apartment units, the higher capital cost of natural gas further decreases cost competitiveness of natural gas in space and water heating applications. Smaller spaces have lower consumption. Thus, electricity for those dwellings is most likely billed under BC Hydro's Step 1[19] rate, which makes electricity an even more cost effective energy option.

Figure 14 and Figure 15 present a historical view of FEI's competitiveness with space heating.[20] As shown in Figure 14 below, FEI's burner tip rate absent the capital costs (indicative of a customer that already has appliances installed) have been above the average rate and Step 1 electric equivalents until recently when BC Hydro's electric rates increased.

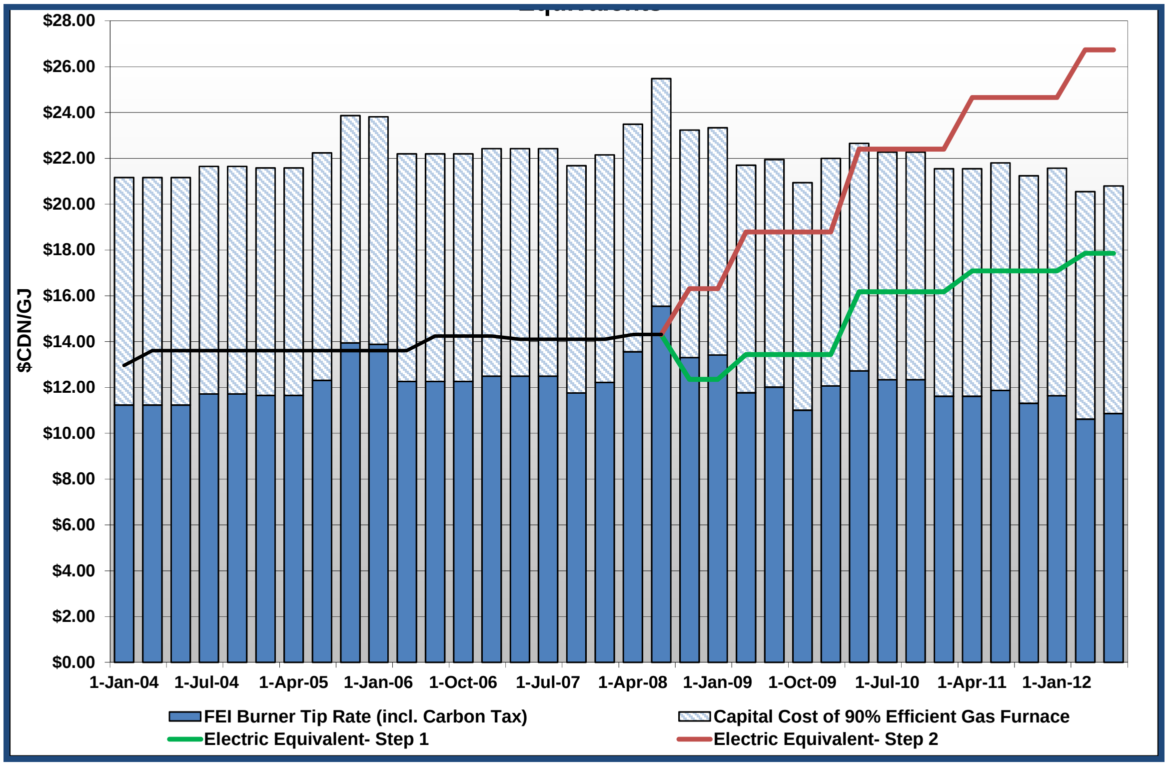
**Figure 14. Existing Space Heating Burner Tip Rate vs. Electric Equivalents**




[19] BC Hydro Step 1 Residential Rate is lower in terms of price than BC Hydro Step 2 Residential Rate.
[20] FEI burner tip rate presented in the figure includes the commodity charge, midstream charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 BC Hydro RIB rate electric equivalents have been adjusted using a 90% efficiency to represent the average efficiency level of a new gas fired furnace in Figure 14. Similarly, the Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers in Figure 15. It is important to note that the rate the BC Hydro customers ultimately pay is dependent on their actual consumptions (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

The inclusion of the upfront capital costs associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces FEI's competitive position against the electric equivalents. From January 2004 to about January 2011, FEI's burner tip rate plus the capital cost of about $9.93/GJ put the total cost per GJ above the Step 2 electric equivalent. Higher total costs of installing gas over electric indicate to the consumer that electricity is the more economical option.

**Figure 15. New Space Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents**



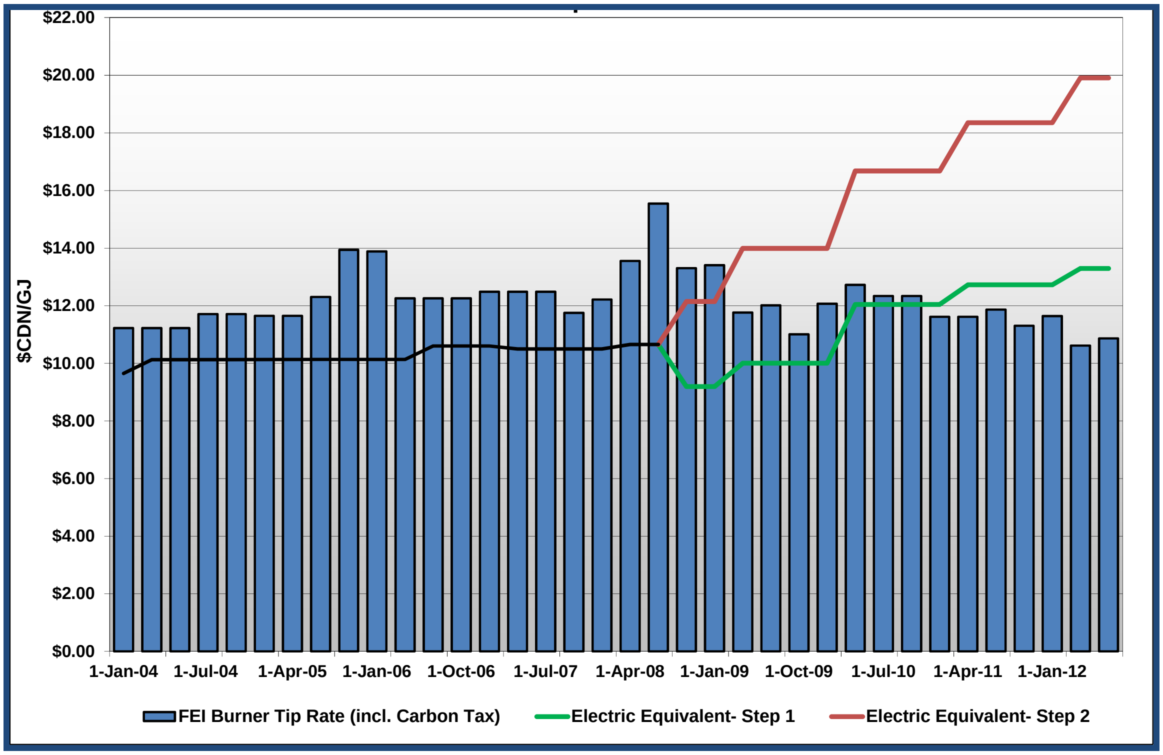

The attraction and retention of hot water heating load is even more challenging for FEI than attracting and retaining space heating load, because natural gas water heaters are lower efficiency and electric water heating makes more use of Step 1 priced electricity.

Figure 16 and Figure 17 below present a historical view of FEI's competitiveness in the water heating market. The FEI burner tip rate presented in the figure includes the commodity charge, midstream charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 electric equivalents have been adjusted using a 67% efficiency to represent the efficiency level of a gas fired hot water heater.[21]

[21] The average efficiency for a gas fired hot water heater is assumed to be 60%, while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater.

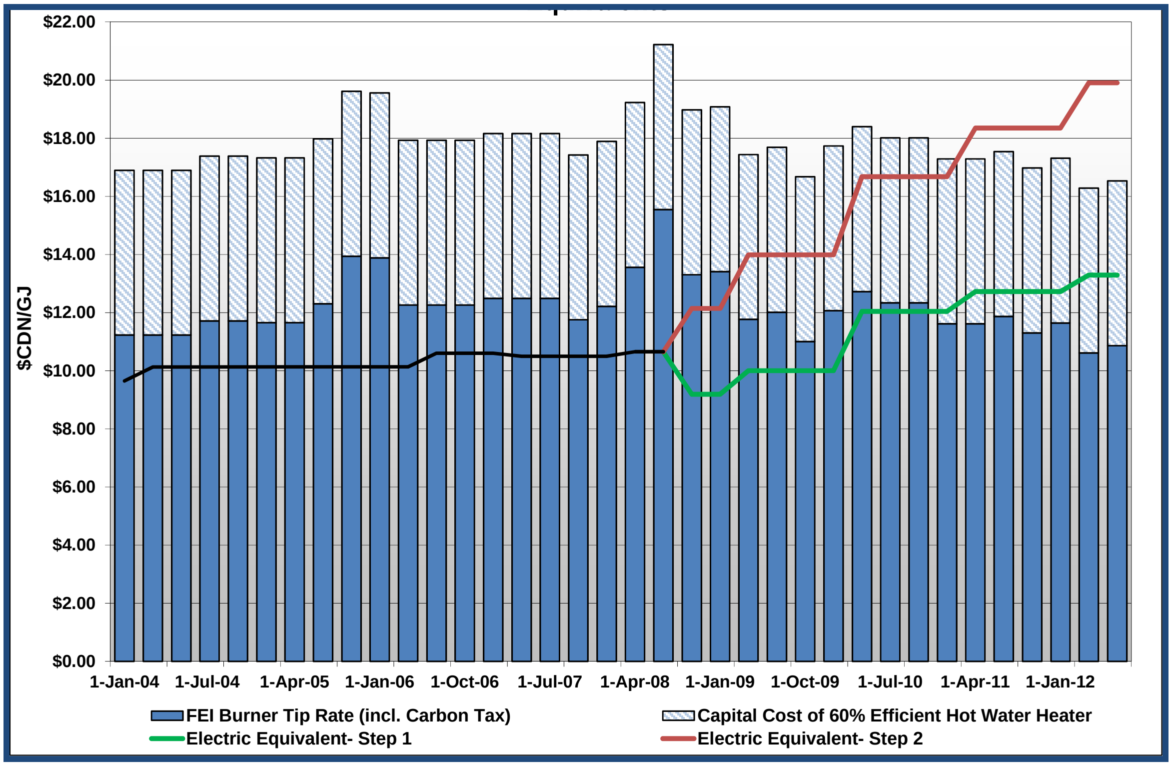
Figure 16 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the energy equipment is a sunk cost.

**Figure 16. Existing Water Heating: Burner Tip Rate and Capital Cost vs. Electric Equivalents**




The inclusion of the upfront capital costs associated with the installation of a gas hot water heater reduces FEI's competitive position against the electric equivalents. From January 2004 to about January 2011, FEI's burner tip rate plus the capital cost of about $5.67/GJ put the total cost per GJ above the Step 2 and Step 1 electric equivalents.

**Figure 17. New Water Heating Burner: Tip Rate and Capital Cost vs. Electric Equivalents**




Until recently with the increase in BC Hydro electric rates, FEI's burner tip rate plus capital costs have totalled marginally above the Step 2 electric equivalent. They remain significantly above the Step 1 electric equivalent.

The results presented above for space and water heating show that, historically, electricity costs have compared favourably to natural gas when capital costs are taken into consideration. It is only recently, in the context of the lowest natural gas commodity prices in a decade, that the price competitiveness of natural gas has improved. However, if the higher natural gas commodity price forecasts of industry experts materialize, then FEI's current price competitiveness in certain applications and situations with electricity will again be eroded.

## 6. MARKET SHIFTS RISK

The choice of energy, and how it is consumed and produced, is influenced by the introduction of new technology and energy forms, changing customer perceptions of energy, and the types of homes being built. Market shifts in these areas continue to pose challenges to FEI's ability to attract and retain customers, and maintain market share and throughput levels. Data obtained since the 2009 ROE and Capital Structure proceeding has reaffirmed that the declining trend in FEI's throughput levels is mainly due to two continuing trends: declining annual use rates from existing and new customers; and, the declining rate of capture of the new construction market, particularly in the multi-family sector.

## 6.1 – New Technology and Energy Forms

The adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business of providing natural gas for space and water heating.

Integrated, end-use energy solutions can displace conventional fuels with low or no-carbon energy sources produced closer to point of consumption. Examples of technologies and energy forms that can reduce the need for natural gas for heating include: air pumps, geo-exchange; waste heat recovery; biomass; and solar thermal energy systems. These energy forms and technologies are examples of integrated energy solutions that utilize thermal heating energy from the environment to replace or supplement traditional natural gas or electrically fired space and water heating systems.

The application of existing alternative technologies and the introduction and adoption of new technologies and energy forms has implications for FEI.

- First, while some technologies are complimentary to FEI's core natural gas business, others are not. Technologies such as air source and ground source heat pumps may not use natural gas at all, or the role of natural gas is limited to that of a back-up fuel source (which results in less natural gas throughput than would be the case were the same customers to be served from 100% natural gas for space and water heating).

- Second, the changing landscape of technologies influences codes and regulations and building design and controls, which can have an impact on energy use. For example, new and replacement residential furnace equipment in BC has to be at least 90% efficient.

- Third, the availability of new technology and energy from multiple sources can accelerate customer demand for renewable energy forms.

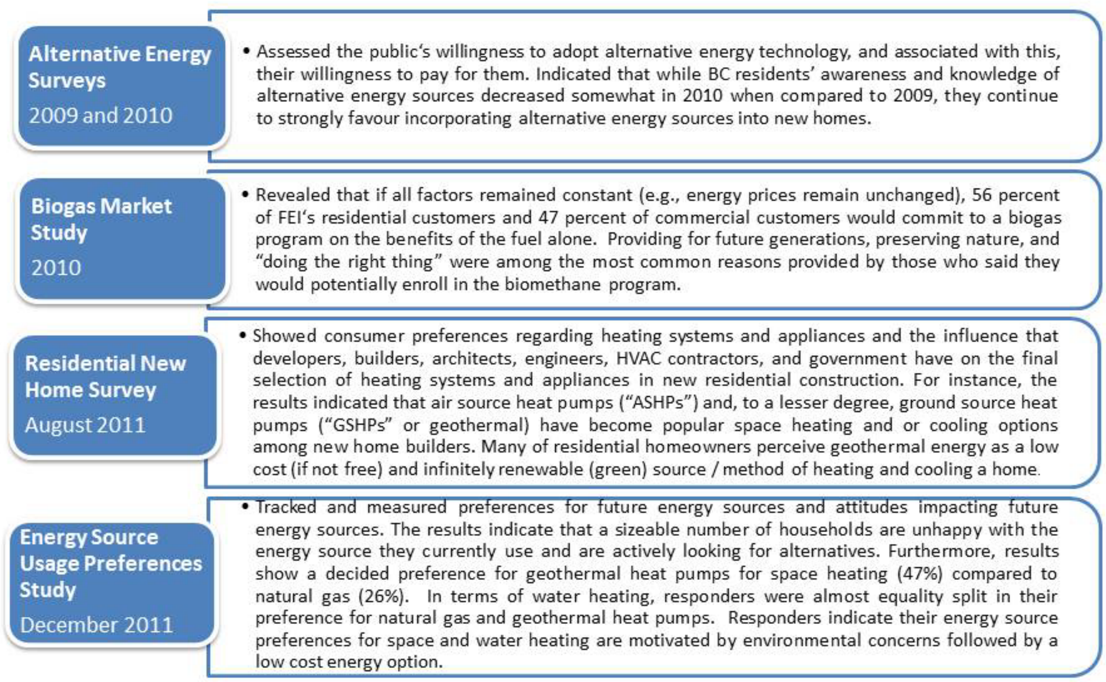
In recent years, non-government organizations such as the Community Energy Association and Quality Urban Energy Systems of Tomorrow ("Quest") are acting as catalysts to spur interest in district energy systems. Government is also a factor in the trends towards alternative energy forms. The Province has expressed support for the development of district energy systems in a number of ways. For example, the Province has developed a promotional factsheet entitled the "District Energy Sector in British Columbia", which identifies district energy systems as an efficient way to heat and cool buildings and reduce greenhouse gas emissions. Also, the recently established RuralBC website, which provides an easy reference point for communities to access resources and program funding in various areas, notes that funding is available to study the viability of district energy systems in communities across the province and to assist in implementing them. Examples of requirements adopted by local governments for developers to consider alternative energy systems are addressed later in section 9.2 of this Appendix.

## 6.2 – Perception of Energy

Historically, customer energy choices tended to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. Customers[22] are now also influenced by a desire to use energy efficiently and to adopt lower carbon and renewable energy sources. This creates challenges for natural gas utilities generally in retaining and attracting heating load, despite the lower natural gas commodity prices currently being experienced.

There is both anecdotal and survey evidence of changing customer perceptions of the various forms of energy. During the normal course of business, FEI consults with existing and potential customers as well as other stakeholders[23] regarding the use of natural gas and the role of FEI in providing energy for the Province. FEI has conducted a number of surveys and studies since the 2009 ROE and Capital Structure Application that show customers' awareness, commitment, perceptions and preferences of energy sources and a desire among some customers to move away from natural gas to "greener alternatives" of renewable and alternative energy sources. Figure 18 summarizes these surveys and studies.

**Figure 18. Summary of Customer Perception Research**




[22] The term "customer" or "consumer" in this section to mean developers, engineers, architects, commercial and industrial customers, institutional customers and municipal and government stakeholders. This customer group represents those in the marketplace who are the key decision makers determining the type of energy a building or house will use. In the case of developers, engineers and architects, this group represents thousands of end use customers who purchase a home with the energy choice selected by the developer.

[23] Stakeholder groups are comprised of customer organizations, government agencies and municipalities, industry, trades, manufacturers, NGOs, advocacy groups, other utilities, and First Nations.

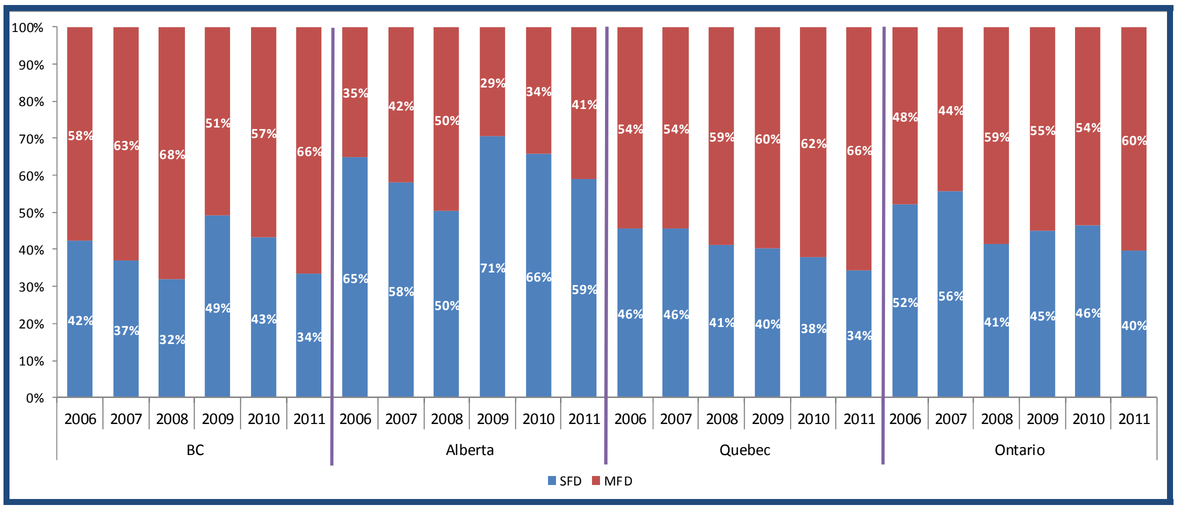
These studies show that customers are generally aware that greener alternatives to natural gas exist, and that there is willingness among some customers to consider and adopt those technologies.

## 6.3 – Housing Types

The market shift in new home development (from single family to multi-family) is adversely impacting FEI's natural gas use and capture rates.

As shown in Figure 19, single family dwelling housing starts have been declining in BC while multi-family housing starts have experienced strong growth, specifically since the declines in 2009. Drivers for the increase in multi-family dwellings include affordability, `shortage of building space, population growth and climate change policies.[24]

**Figure 19. Single Dwelling vs. Multi-Family Housing Starts in Different Provinces within Canada**




There are two key implications for FEI of the move towards multi-family dwellings.

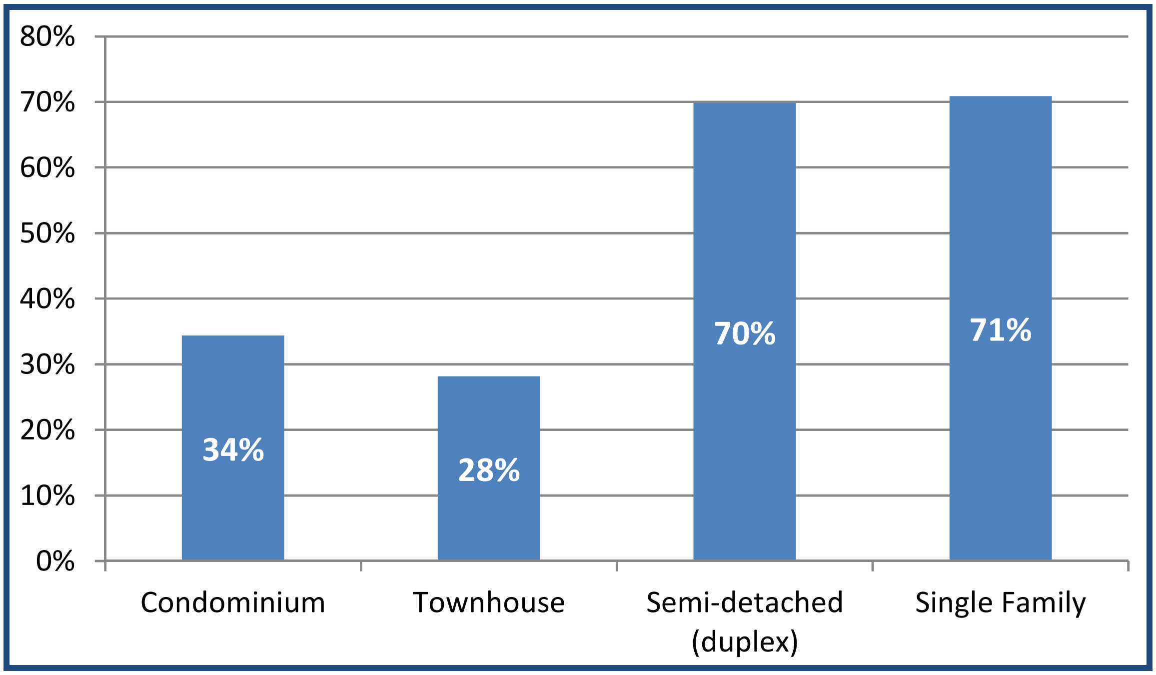
First, the 2008 Residential End Use Study ("REUS") survey shows that, on average, annual gas consumption for natural gas is greater in single-family dwellings than in multi-dwellings.[25] With single-family dwellings housing starts in decline and multi-family dwellings increasing, natural gas utilities will need to capture more multi-family dwellings to offset declines from existing customers to maintain existing throughput levels.

Second, natural gas has a low penetration rate in multi-family dwellings. Figure 20 shows FEI's capture rates by housing types for 2011.

[24] For example, Vancouver's Climate Change Action Plan stipulates that: 'the most important long range strategy for managing housing- and transportation related greenhouse gas emissions in an urban context is land use planning for higher density, mixed-use, walkable communities – frequently referred to as smart growth." City of Vancouver. EcoDensity: How Density, Design, and Land Use Will Contribute to Environmental Sustainability, Affordability, and Livability. http://vancouver.ca/commsvcs/ecocity/pdf/EcoDensity%20Summary%20Report%20_web(1).pdf

[25] The average consumption for single family detached is about 105 GJ, for duplex is 85 GJs, for row/townhouses is 70 GJs, for mobile homes is 60GJs, and for apartments is 30 GJs, as per Residential End Use Study, November 30, 2009.

**Figure 20. FEI's Capture Rates by Housing Type**




The main underlying factor that influences the declining capture rates of natural gas is that builder decisions are being driven by the unfavorable economics of installing a natural gas application.[26] Developers have more capital cost incentives to install electric baseboard heating for multi-family dwellings, as opposed to natural gas, given that it is cheaper to install than natural gas infrastructure. Natural gas space heating equipment occupies valuable space within a multi-family unit.

Over the longer term it is expected that electricity will continue enjoying a greater market share in the multi-family dwelling sector than natural gas.[27]

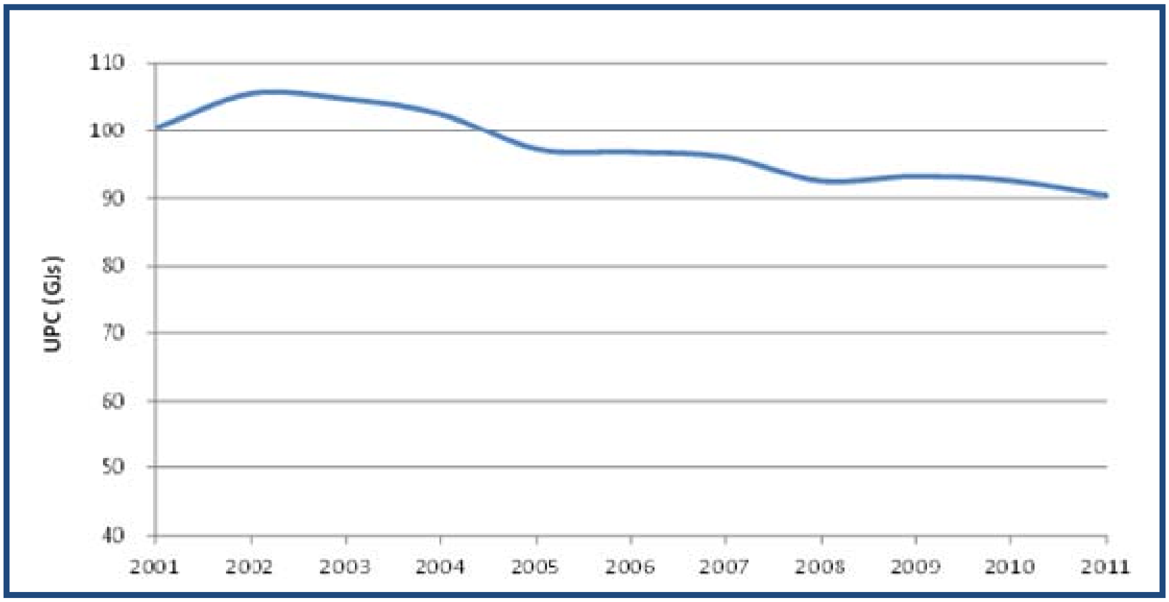
## 6.4 – Changes in Energy Use

FEI is facing declining annual use rates from its existing customers, primarily in the residential sector. This has a direct impact on throughput levels.

As shown in the Figure 21, FEI's residential annual use per customer, or "UPC", has declined 15 percent since 2002.[28]

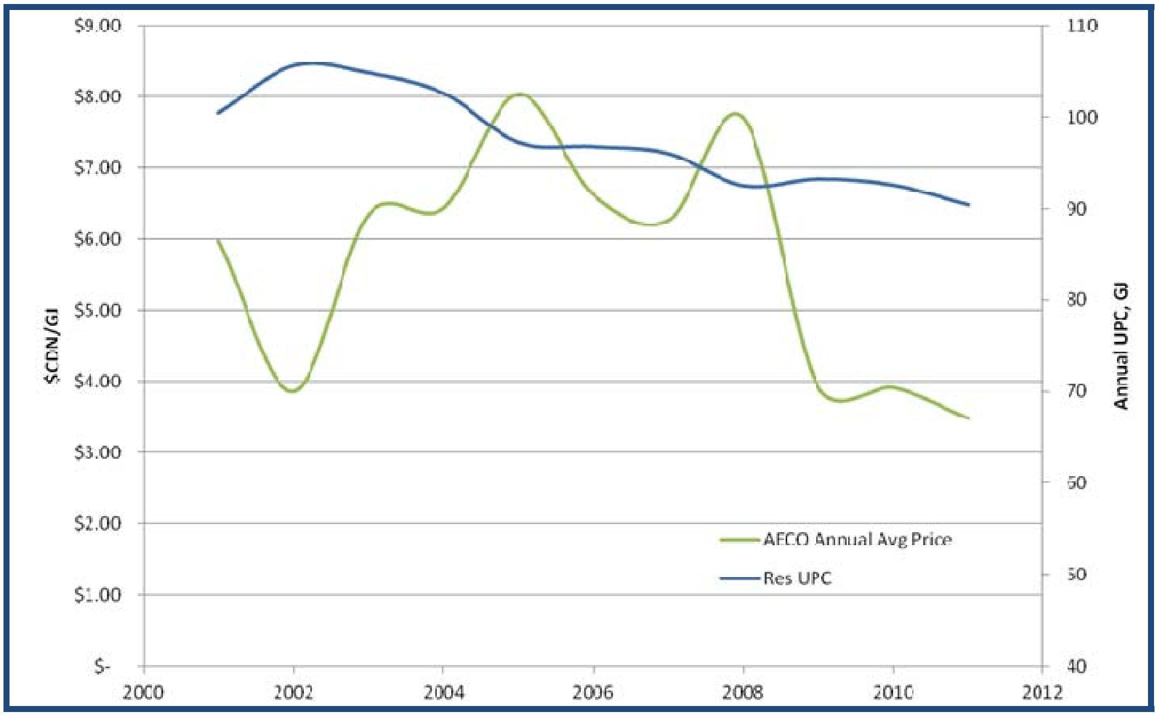
[26] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges. page 36.
[27] BC Hydro confirmed this expectation in its 2012 Integrated Resource Plan, stating: *"Since row houses and apartments are more likely to be built with electric heat compared to single family homes, the market share for electrically-heated housing is expected to increase."* (Appendix 2A, 2011 Electric Load Forecast, page 27)
[28] The use per customer rates are based on historical data. It is expected that new customers use per account will be much lower than existing customers for a variety of reasons.

**Figure 21. FEI's Residential (Rate Schedule 1) Normalized UPC for Existing Customers**




The decline in UPC is attributable to a variety of factors, including technological advances and energy efficiency improvements, building codes, size and type of homes being built, and type of appliance being installed in these homes. Commodity prices are also expected to influence customer use over time; however, actual changes in customer behavior in response to prices is difficult to determine from historical data. As shown in Figure 22 below for the residential sector, average use per customer decreased during the period of rising prices but UPC has not rebounded during the low price environment experienced over the last couple of years. This is likely due to the influence of these other factors.

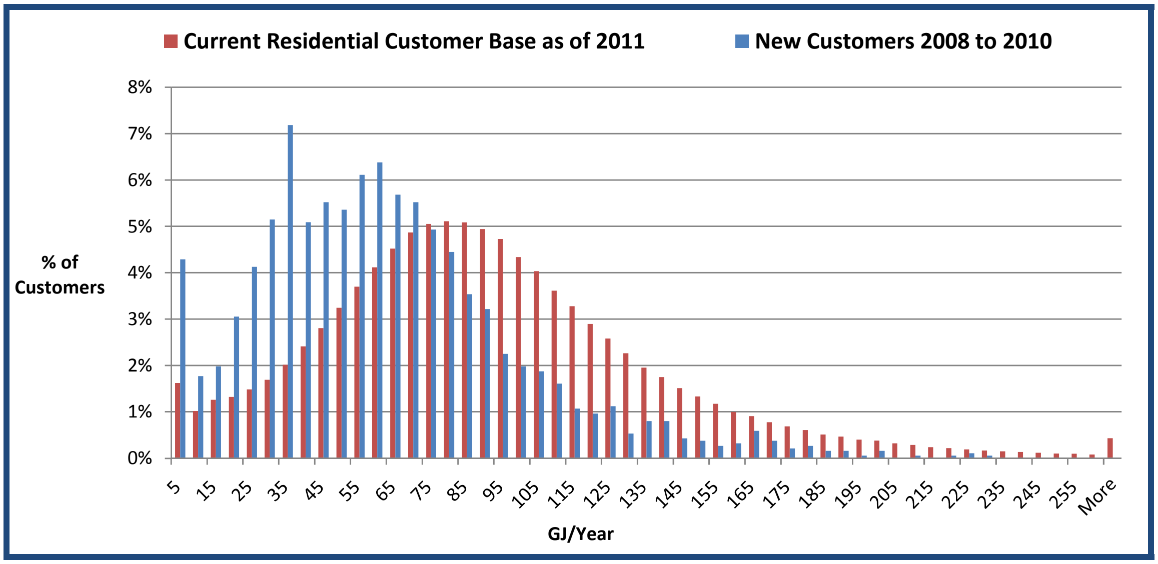
**Figure 22. FEI's Residential UPC and Commodity Price**




Short-run price elasticity reflects behavioural changes that a customer may make in response to changes in price, whereas changes in energy-consuming equipment (capital) would be captured in the long-run elasticity. Long-run elasticities are expected to be larger because customers can make adjustments in the capital stock.

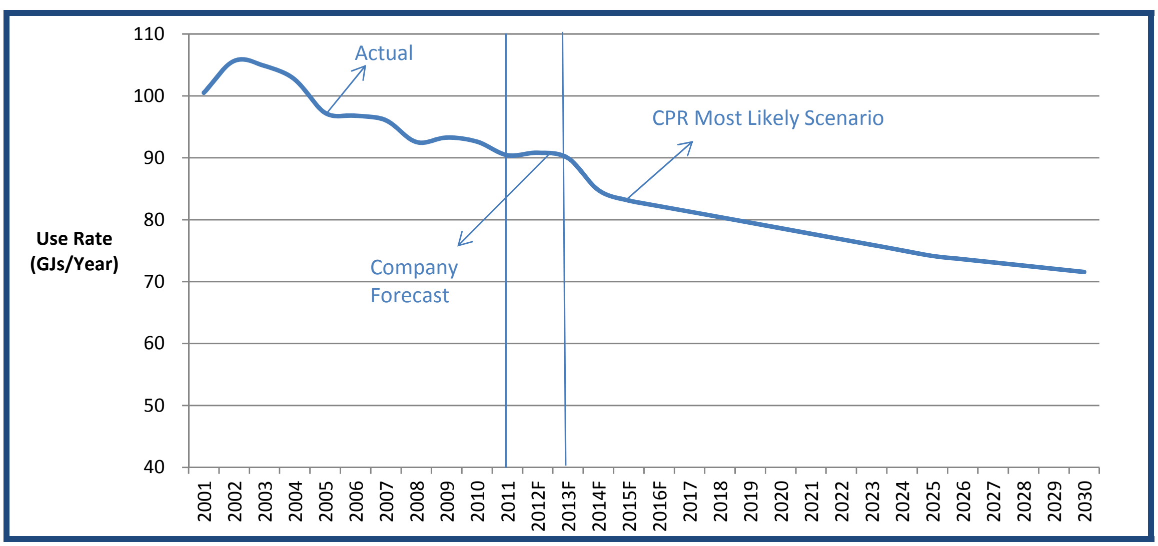
The implication of the research findings is that new customers of FEI have a lower UPC compared to the existing customers as is illustrated in Figure 23. The frequency distribution curves for the existing and new customers are centered on 85 GJ and 45 GJ, respectively, each estimating the population norms of 85 and 45 GJs. This means that an existing natural gas residential customer on average consumes 85/GJ in a normal year as compared to a new residential customer which will consume 45/GJ in a normal year. This trend in UPC for new customer's additions in the residential sector will have long-term impacts on the throughput from this sector.

**Figure 23. FEI's Residential Frequency Distribution**




FortisBC Energy's forecast of the decline in residential use rates is in line with 2010 Conservation Potential Review ("CPR").[29] According to the CPR, natural gas consumption in the residential sector will naturally decline by an additional 2 percent from 2010 to 2030 in the absence of continued demand-side management. The CPR also estimated that an additional total reduction in demand of 5 percent by 2030 is mostly likely if new demand-side measures are implemented. Figure 24 illustrates the trend of FEI's residential use rate for existing and new customers.

**Figure 24. FEI's Residential UPC Actual and Forecast**



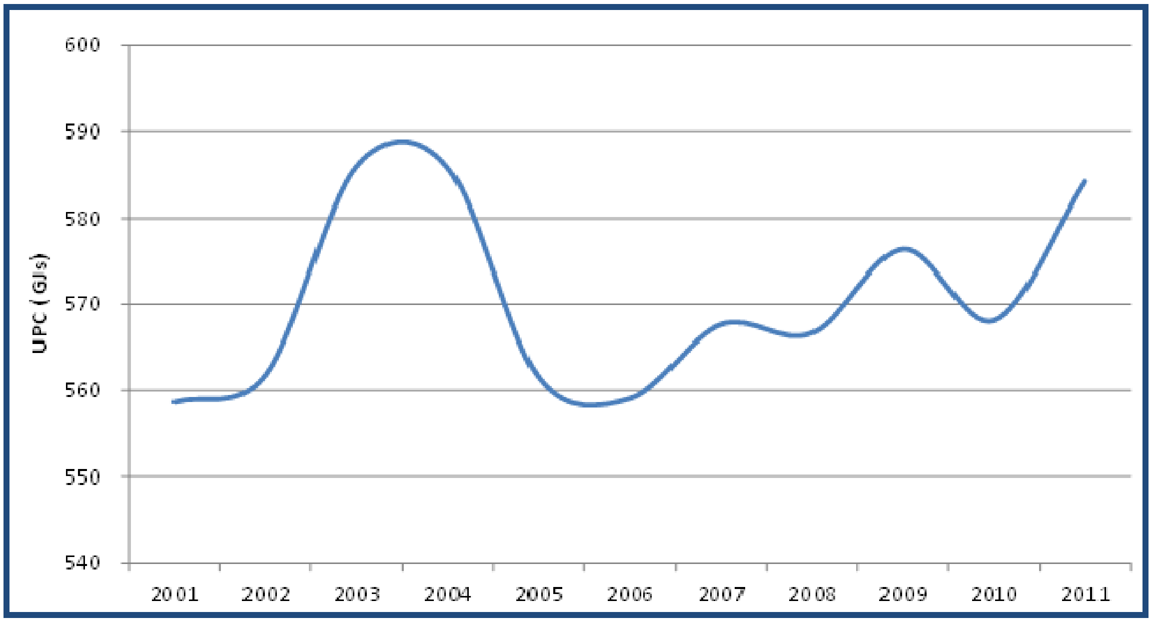

**Note:** The forecast is based on most reliable and available source of data at this time. The CPR most likely scenario is based on an expected level of DSM funding.

---

[29] Conservation Potential Review is a study conducted by ICF Marbek in 2010. It provides comprehensive view of potential EEC savings over 10 to 20 year period.

FEI's commercial customers (Rate Schedule 2, 3 and 23) consist of customers from a wide variety of business sectors. Changes in the factors affecting their natural gas use lead to significant swings in the commercial use rates. Figure 25 below shows the volatility in the annual use rate for the commercial rate class.

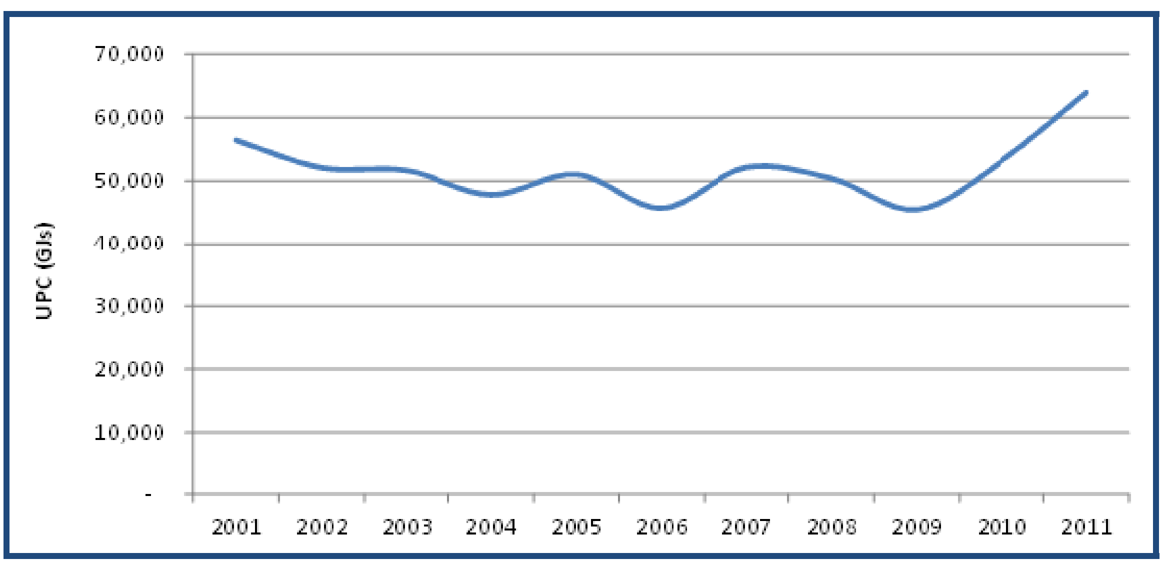
**Figure 25. FEI's Commercial UPC**




Forecasting the future use rate for the commercial rate classes is difficult due to the volatility in use rates for this sector.

FEI historical industrial UPC is displayed in Figure 26.

**Figure 26. FEI's Industrial UPC**



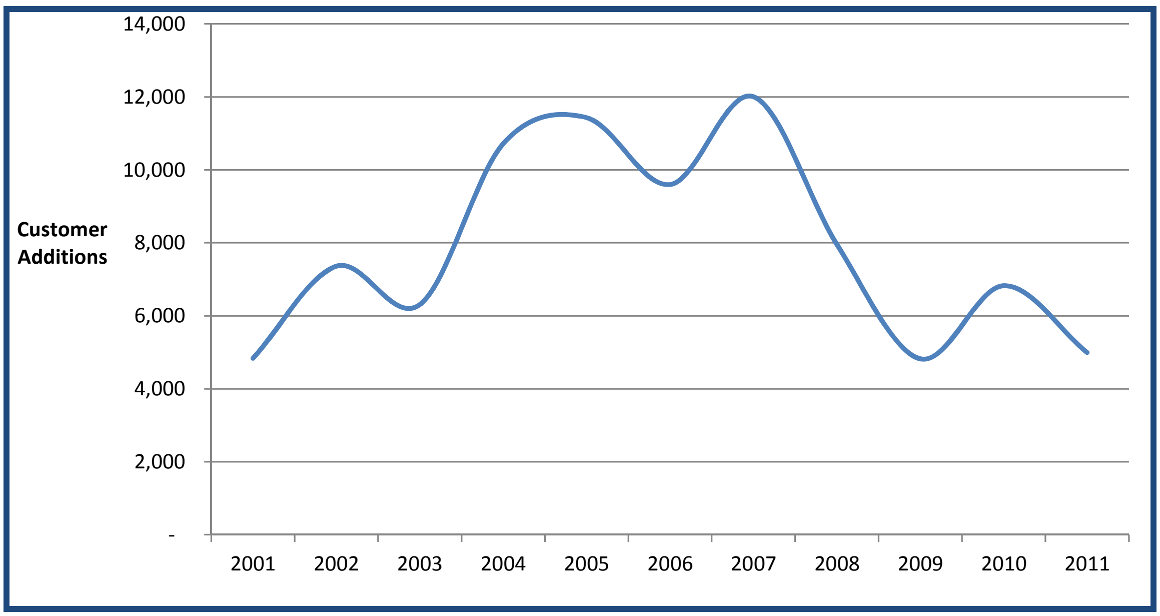
In 2010-2011, FEI experienced a modest increase in throughput in the industrial sector as some industrial customers have fuel switched towards natural gas to take advantage of the lower natural gas prices compared to their alternatives. Whether this uptick in the industrial sector will be maintained in the long-term is dependent on the competitiveness of natural gas to alternatives for each industrial customer. In addition, industrial volume increases are limited due to the number of customers that have been lost in this sector since 2001.

## 6.5 – Changes in Customer Additions

A further trend that compounds the declining use per customer is the lower capture rate for new building stock. FEI's ability to manage risk is in part dependent on its ability to attract and retain new customers to offset declines in UPC, and this is proving to be more difficult than it has been historically.

As shown below in Figure 27, FEI's net customer additions have declined since 2007. FEI added 4,994 residential customers (net of attrition) in 2011, which decreased by 58 percent compared to 2007.

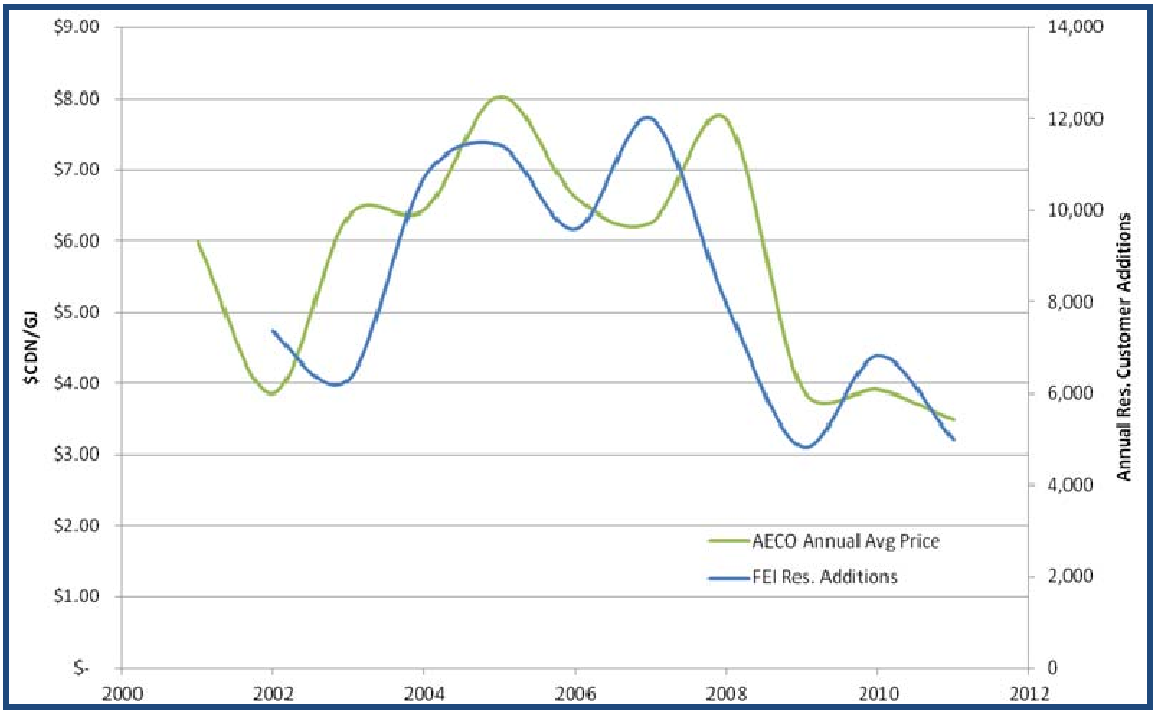
**Figure 27. FEI's Residential Customer Additions**




Customer additions are influenced by a number of factors, including the new construction market in BC, and the previously-discussed shift in the housing market towards more higher-density housing types where the Company has a low capture rate.

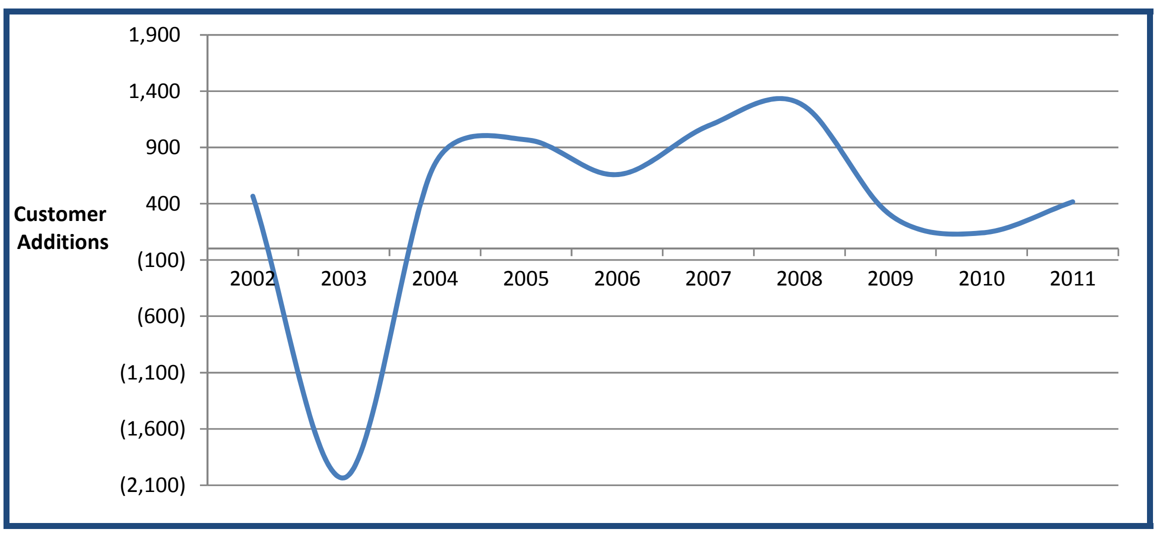
The recent experience with low natural gas commodity prices is not expected to make it materially easier to attract new customers. Figure 28 highlights the weak relationship between commodity prices and customer additions; FEI has captured more customers when commodity prices were higher and has captured fewer customers when commodity prices were lower.

**Figure 28. FEI's Residential Customer Additions and Commodity Prices**




For commercial customers, as demonstrated by Figure 29, net customer additions are highly volatile and do not exhibit a clear trend.

**Figure 29. FEI's Commercial Customer Additions**




FEI does not forecast industrial customer and relies on customer survey's to determine throughput levels for the industrial sector.

## 7. ENERGY SUPPLY RISK

In this section, FEI addresses energy supply risk. Ms. McShane defines supply risk as "relat[ing] to the physical availability of the commodities required to deliver service to end use customers. Supply risk also includes, for gas utilities, exposure to supply interruption, and thus the degree of reliance on a single supply basin and/or pipeline and the availability of storage." Since 2009, the shale gas discoveries have improved the long-term supply outlook for natural gas across North America. The underlying infrastructure to move gas to FEI's service territory has not changed. Competition for the new supply may change FEI's cost to access the supply.

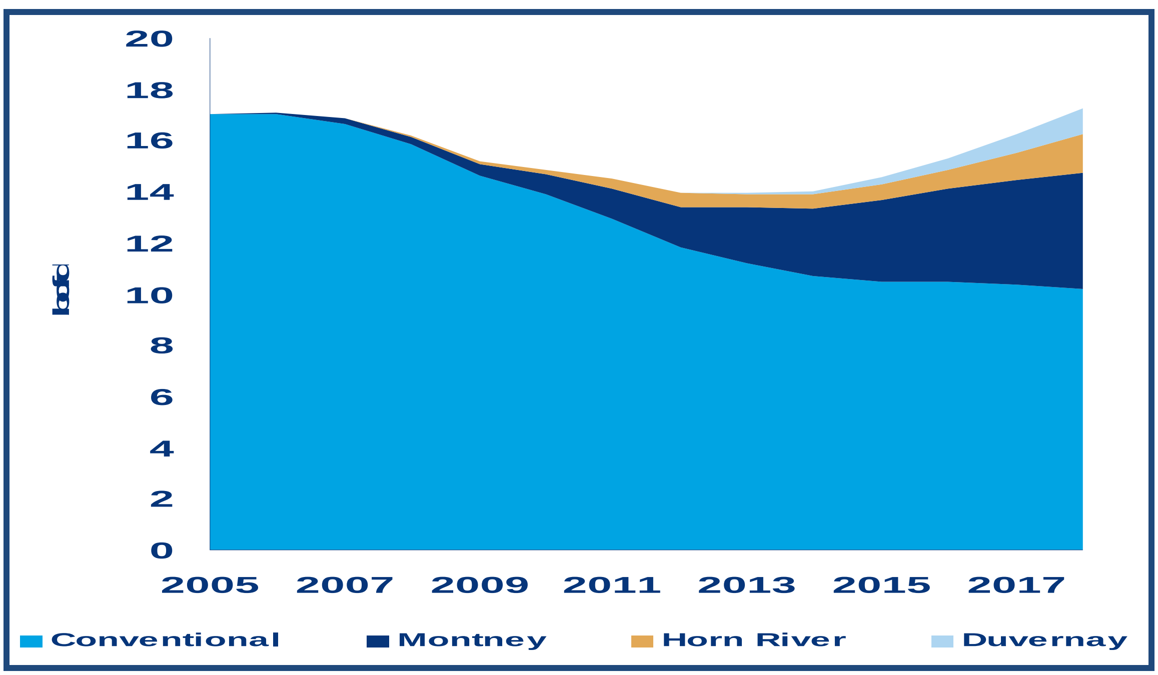
### 7.1 – Availability of Supply

The risk associated with declining gas supply reserves in BC has diminished compared to pre-2008 levels due to the development of shale gas plays in Northeast BC. However, if the full potential of the B.C. shale gas plays is to be realized, producers will require connections to new and more liquid markets be developed. This, in turn, may create challenges for FEI in accessing this additional gas at competitive prices than faced by utilities in the Alberta market.

#### *Cost-Effectiveness of New Supply in BC*

Figure 30 highlights the increase in supply since the discovery of shale gas deposits the Western Canadian Sedimentary Basin ("WCSB").

**Figure 30. WCSB Production (Actual and Forecast)**




**Source:** Wood Mackenzie North American Gas Service, April 2012.

The forecasts for increased natural gas production in BC are still somewhat uncertain. While there is significant supply potential within northern BC, this supply will likely not be developed fully unless and until there are markets for this new production. The supply and demand dynamics across North America are currently undergoing fundamental change. Traditional eastern markets for WCSB gas are becoming less dependent on WCSB gas due to the availability and accessibility of large volume gas supply from large scale supply sources within the US, such as the Marcellus. As result, overall production increases in WCSB will depend on changes in regional demand (i.e. industrial demand from oil sands development and expansion of gas-fired generation load) and/or if producers are able to cost effectively connect to new export markets for LNG.

The discovery of significant shale gas deposits in BC does not translate in to guaranteed access to cost effective supply for FEI. Access and cost are affected by a variety of factors.

First, the region is primarily reliant on the Westcoast Energy Inc. ("Westcoast") transmission system for delivery of gas supply to its marketplace. BC production travels long distances on the Westcoast pipeline for delivery to market centers such as the interior and Lower Mainland. BC has only one underground storage facility which is located close to production sources rather than load centers. As such, FEI is highly reliant on the Westcoast pipeline system for delivery to load centers in the winter months. The total volume of gas supply that flows on the Westcoast system to markets in BC and the US Pacific Northwest during cold periods in the winter months equates to about 2 BCF/d from Station 2. Outages or operational issues in the producing region or the Westcoast pipeline can result in supply cuts to utilities and their customers. The high level of reliance for gas supply from distant production sources and a single pipeline system subjects FEI to supply interruption risk.

Second, tightness in the availability of storage capacity coupled with pipeline constraints in the Pacific Northwest region can negatively affect the price at which FEI is able to contract for these resources. Shorter duration market storage facilities in the region are largely owned by utilities in the US Pacific Northwest and they have been utilizing an increasing share of those resources for their own use. The overall marketplace for gas supply has a significantly lower level of liquidity compared to Alberta and with no accessibility to intraday gas supply. In addition, pipeline capacity to the Alberta marketplace for BC production has significantly expanded, which provides optionality for producers to bypass the BC and Station 2 marketplace altogether. Currently, pricing for gas contracts in BC is higher than the Alberta marketplace especially during the winter months even though the supply is sourced and produced in BC.

Third, regulatory developments in other jurisdictions can affect FEI's access to cost effective supply. There are currently a number of Nova Gas Transmission Limited ("NGTL"), TransCanada Pipelines Limited ("TCPL") and Westcoast infrastructure applications in front of the National Energy Board ("NEB" or "Board") at this time. The decisions regarding these applications could have an impact on the market in western Canada and impact on FEI's supply procurement activities. Moreover, the tolling outcomes of TCPL's restructuring efforts will impact the flow of gas and pricing dynamics in regional hubs including the pace of development of BC's shale gas basins. Toll increases on pipelines and competition for BC supply from the Alberta marketplace or other Asian markets for LNG could all put upward pressure on cost of natural gas for BC customers.

Fourth, there is also uncertainty regarding the long-term cost effectiveness of supply at Station 2. FEI continues to be greatly dependent on gas supply that is available at the Station 2 marketplace and Westcoast's T-South system for supply delivery each day into its system. The development of an export LNG market could increase the availability of gas at Station 2, especially if a portion of that new supply flows via the Station 2 marketplace. However, if new supply does not flow via the Station 2 market hub, then FEI may not be able to access that new supply cost effectively. For example, Station 2 had been trading at a discount relative to the AECO/NIT market as a result of supply exceeding the availability of infrastructure required to transport that supply to the Alberta marketplace, however, this situation is currently reversed. At this time last year, Station 2 supply for the upcoming winter 2011/12 was priced at a $0.25/GJ discount to the AECO monthly index. This year, for the upcoming winter 2012/13, Station 2 supply is currently priced at a $0.08/GJ premium to the AECO monthly index. This suggests that the availability of infrastructure to transport supply to Alberta has started to exceed the availability of supply. FEI's risk for pricing of gas supply is therefore largely dependent upon the pace of development of supply basins in north eastern BC and how that supply becomes available to the market hubs.

## *Jurisdictional Comparison*

The supply and infrastructure for natural gas in BC is significantly different from the Alberta and Ontario marketplaces. The key differences relate to overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the Alberta and Ontario regions compared to BC. In addition, the amount of gas that flows in the Alberta/Ontario systems compared to BC is also different.

The Alberta marketplace is a very liquid marketplace on a year round basis as it consists of a wide range of suppliers and resellers who are available on a daily basis to buyers. The number of transactions conducted each day facilitates the ease of gas supply accessibility on a year round basis, leading to a highly efficient and effective marketplace. The daily availability of gas supply received in the Alberta market from sources averages just under 10 BCF/d. In addition, gas supply is readily available to buyers and sellers on an intraday basis each day in order to manage gas demand within a utility's operating region. The high level of gas flow in the Alberta market combined with a variety of available storage facilities provides gas supply to customers with no service disruptions in the event of gas plant outages. The close proximity of gas production to market and load centres also reduces the risk of gas supply disruptions for consumers. Although conventional Alberta gas production is declining, the availability of shale gas from BC coupled with significant increases in pipeline connectivity between BC and Alberta is anticipated to maintain the strength and liquidity of the Alberta marketplace.

The natural gas marketplace in Ontario is experiencing change whereby that region has started to benefit from shale gas supply within its operating region from basins such as the Marcellus. In addition, Ontario has historically benefited from sizable storage and deliverability within close proximity to load and market centers. Furthermore, the large

Ontario gas utilities Union Gas and Enbridge Gas are owners and operators of the storage facilities in the area. Ontario's primary trading hub, the Dawn Hub, can access natural gas from the WCSB as well as a number of U.S. supply basins through a variety of pipelines feeding into that Dawn hub. With the expansion of pipeline capacity, this hub will be able to readily access gas from the Marcellus region. Unlike the BC and PNW marketplace, where storage is limited, approximately 265 PJ of underground gas storage owned and operated by utilities also connect into the Dawn Hub providing substantial operational flexibility for the region.

The risk associated with declining gas supply reserves in BC have diminished compared to pre-2008 levels due to the discovery of shale gas. However, the risk associated with the production and availability of this supply at competitive prices in BC compared to the Alberta market has increased due to greater optionality for producers. As a result, upward pressure on commodity prices for FEI to acquire gas supply at Station 2 is likely.

### 7.2 – Security of Supply

Regional infrastructure constraints continue to impact security of supply for FEI. The ability of FEI to continue to provide gas supply to its core market customers, under severe winter conditions and emergencies, is a primary prerequisite for the contracting of a variety of resources within the gas supply portfolios. The contracting of term gas supply with producers at different market hubs, and contracting of firm pipeline capacity and storage resources with third parties for delivery of all gas to load centres provides security of supply in the portfolio. In FEI's case, the diversity of resources also facilitates the provision of backstopping supply for customers, who have moved to marketers for their commodity supply, in the event of failure by one or more of the Commodity Unbundling Marketers.

FEI remains highly dependent on a few key resources to ensure cost effective and reliable gas supply to its customers. For example, Westcoast's T-South pipeline and the Southern Crossing Pipeline ("SCP") enable delivery of a significant amount of FEI's supply. The SCP system has capacity constraints on a portion of its system for delivery of gas to the Lower Mainland. However, the availability of the Mt. Hayes storage in 2011 has provided some relief to FEI by providing an on-system source of gas supply available for short periods of time during cold weather spells and emergencies such as pipeline outages on the T-South system. The construction of the Mt. Hayes facility was approved by the Commission in 2008 and put into service in April 2011.

Overall, other than the completion of the Mt. Hayes facility, the risks for FEI associated with the portfolio and regional infrastructure have not materially changed in recent years.

## 8. OPERATING RISK

In this section, the FBCU address operational risk. Ms. McShane defines operational risk as "encompass[ing] the physical risks to the revenue generating capabilities of the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather." The FBCU have addressed operating risks in this section with reference to infrastructure integrity, third party damages, and unexpected events. Overall, operating risk has remained relatively unchanged since 2009.

## 8.1 – Infrastructure Integrity

FEI is responsible for managing gas transmission and distribution asset with a book value of approximately $2.3 billion and an approximate replacement value of $5.5 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40-55 years. These assets face an increasing rate of deterioration as they approach the end of their service life. FEI anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

The operating risk presented by assets relates to the ability of service providers to respond to long-term utility infrastructure replacement programs. There are many variables impacting the useful life of underground pipe including pipe material, pipe coating, soil conditions, external interference, corrosion, etc. FEI has several programs in place to monitor, inspect and assess pipe condition and as a result of these assessments has developed longer term capital programs to replace sections of pipe that are reaching the end of their useful life. The primary challenges in terms of executing on infrastructure replacement plans are, firstly, in obtaining regulatory approvals, and secondly, in obtaining project resources to perform the work. These would include a mix of project managers and engineers, planners and field resources, etc. Other natural gas companies in the country as well as other utilities in the Province (particularly BC Hydro) are competing for the same resources over similar time periods potentially driving up service provider costs.

## 8.2 – Third Party Damages

Third party damage refers to a third party either accidentally or deliberately damaging gas assets below ground or above ground. Below ground damage usually takes the form of a contractor, municipality or homeowner excavating in the vicinity of gas infrastructure, following unsafe excavation practices and damaging gas main, service line, or meter which may result in the loss of gas, service interruptions and significant repair costs. The number of third party damages has been on a decreasing trend since 2006. Deliberate third party damage (vandalism, theft, sabotage, terrorism, etc. usually in relation to above ground facilities) remains a relatively low frequency event in FEI in comparison to excavator third party damage.

## 8.3 – Unexpected Events

FEI has a large radial system through mountainous and forested terrain, which is subject to more hazards than operating a natural gas system on the prairies, for example.

Natural events contributing to operating risk in BC include floods, washouts, forest fires, land slippage and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FEI has systems in place to mitigate the impacts of these natural forces. In many cases, pro-active emergency planning can further reduce the impacts of these events. However, given that the extent of these natural events remains unpredictable, they pose one of the higher operating risks to FEI.

## 9. POLITICAL RISK

In this section the FBCU address political risk. Ms. McShane defines political risk as "relat[ing] to the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal Rights." The political landscape is a significant risk factor for FEI.

The British Columbia government and a variety of local governments have been at the forefront of climate change and energy policies[30] These policies and related legislation have put pressure on natural gas in its traditional role in providing heat for space and water heating even though it is the lowest cleanest and lowest emitting fossil fuels. Aboriginal rights issues, and the potential effect of aboriginal rights and title claims on land tenure and project execution, also contributes to FEI's business risk.

The subsections below focus on climate change policies and legislation, GHG emissions reductions requirements, carbon tax, and aboriginal rights.

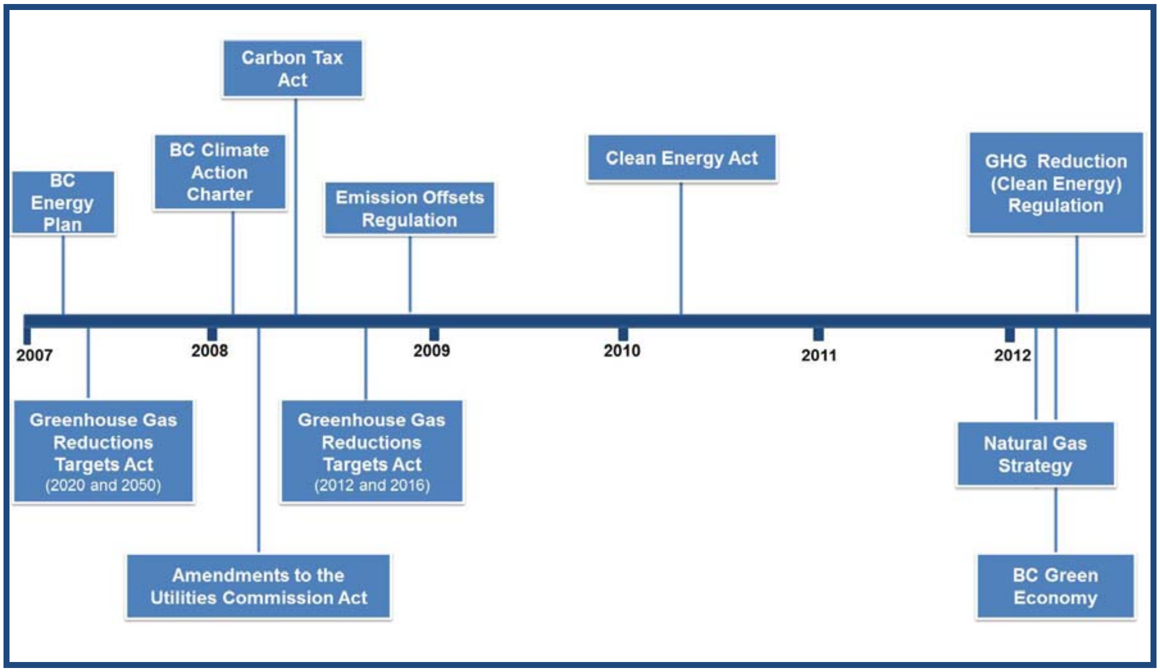
### 9.1 – Energy Policies and Legislation

The Provincial government energy policies, notably the 2007 Energy Plan, and subsequent legislation have focused on the role of clean and renewable energy, including electricity, to meet the energy demands of the province, while at the same time introducing a tax on fossil fuel consumption in BC.

Figure 31 provides a snapshot of all the recent energy and climate change policies and legislation developed in the Province, the majority of which were discussed in the 2009 ROE and Capital Structure proceeding. Since the 2009 ROE and Capital Structure proceeding three major developments have occurred: the *Clean Energy Act* ("*CEA*"), the *Greenhouse Gas Reduction (Clean Energy) Regulation*, and BC's Natural Gas Strategy. These energy policies and legislation are discussed in more detail below. Also, BC's Green Economy report is discussed.

[30] David Suzuki Foundation. All Over the Map 2012: A comparison of Provincial Climate Change Plans.

**Figure 31. Energy Policy and Legislation Timeline**




As demonstrated by its energy policies and legislation, the BC provincial government is pursuing a "green economy" and encouraging the reduction of GHG emissions by having a focus on lowering energy consumption and improving energy efficiency and conservation, and is keen in its search for and development of alternative (and renewable) energy sources.

### *Clean Energy Act*

On April 28, 2010, the BC government announced the *Clean Energy Act* ("*CEA*") (Bill 17), which aims to ensure electricity self-sufficiency at low electricity rates by 2016, to harness BC's clean power potential to create jobs, and to strengthen environmental stewardship and reduce GHG emissions.

Section 2 of the *CEA* sets out BC's energy objectives, almost all of which are directed at energy efficiency and optimization, and reducing GHG emissions in the province. BC's energy objectives have implications for the role of public utilities generally in delivering on the provincial government's initiative to reduce GHG emissions and improve energy efficiency. The *CEA* is supportive of alternative energy to encourage the production of power from alternative sources in the Province. The *CEA's* new definition for "demand side measure" excludes programs designed to encourage electricity-to-natural gas fuel switching that would have the impact of increasing GHGs in the province (even though there may be a net reduction in GHG emissions on a regional basis). As such, the CEA adds to the challenges faced by FEI in maintaining throughput levels.

## Greenhouse Gas Reduction (Clean Energy) Regulation

On May 14, 2012, through a "prescribed undertaking" under section 18 of the *Clean Energy Act*, the Government of British Columbia announced the Greenhouse Gas Reduction (Clean Energy) Regulation, encouraging the adoption of natural gas as a transportation fuel in the Province. The Government's press release stated:

> *"This regulation allows utility companies to deliver natural gas transportation programs, including the opportunities to:*
>
> - *Offer incentives to transportation fleets that would use natural gas, such as buses, trucks or ferries.*
> - *Build, own and operate compressed natural gas fuelling stations or liquefied natural gas fuelling stations.*
> - *Provide training and upgrades to maintenance facilities to safely maintain natural gas-powered vehicles"*

This is the BC government's first legislated attempt[31] to recognize the role of natural gas in reducing cost and GHG emissions for the transportation sector. The market is still in early development and the benefits are yet to be realized. FEI's core business is and will remain for the foreseeable future, space and water heating.

## Natural Gas Strategy

On February 3, 2012, the BC Government released "British Columbia's Natural Gas Strategy: Fueling B.C.'s Economy for the Next Decade and Beyond" and "Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry". This comprehensive Natural Gas Strategy, along with LNG Strategy, describe natural gas as the cleanest-burning fossil fuel and recognizes its ability to foster economic growth opportunities and reduce GHG emissions by replacing coal-fired power plants and oil-based transportation fuel. The Strategy does not, however, advocate a role for natural gas for space and water heating, which is the most significant source of throughput and margin on FEI's system. As discussed above in section 7.1, the development of LNG for export will have implications for natural gas commodity prices, which could ultimately affect natural gas price risk.

[31] On February 3, 2012, the BC Government initially promoted natural gas as a transportation fuel in announcing BC's Natural Gas Strategy. The Natural Gas Strategy is not enacted in law and therefore does not get reflected into legal requirements for BCUC to consider. One of the action items in promoting natural gas as a transportation fuel included: "Work to introduce a regulation under the *Clean Energy Act* to advance a proposed natural gas vehicle program".

### BC Green Economy: Growing Green Jobs

The BC Government's focus on "green economy" is exemplified in its "BC Green Economy: Growing Green Jobs" document[32], released in March 2012, in which it highlights the importance of policies that support innovation, environmental sustainability and job growth. Within this report, the government submits that the center of green economy is the "clean tech" sector, from renewable energy systems and high performance green buildings to clean transportation systems, which create an opportunity for job growth. The role of natural gas in this "green economy" is focused on LNG for transport and export, as opposed to FEI's core business of space and water heating.

## 9.2 – GHG Emissions Reductions

Among the provinces, BC is at the forefront of GHG reduction initiatives. The solutions put in place in BC, which include a focus on reducing the use of natural gas in heating applications, has a disproportionate impact on BC natural gas utilities.

Each of the four provinces examined has instituted various measures to reduce GHG emissions within its jurisdiction. Table 8 shows GHG emissions reduction targets in British Columbia, Alberta, Ontario and Quebec.

**Table 8. GHG Emissions Reduction Targets in Four Jurisdictions across Canada**

| Province | GHG Emissions Reduction Targets |
|---|---|
| **British Columbia** | Reduce by 6% below 2007 levels by 2012<br>Reduce by 16% below 2007 levels by 2016<br>Reduce by 33% below 2007 level by 2020<br>Reduce by 80% below 2007 level by 2050 |
| **Alberta** | Reduce by 20 megatonnes below business as usual by 2010<br>Reduce by 50 megatonnes below business as usual by 2020<br>Reduce by 200 megatonnes below business as usual by 2050<br>(Reduce by 14% below 2005 levels by 2050) |
| **Ontario** | Reduce by 6% below 1990 levels by 2014<br>Reduce by 15% below 1990 levels by 2020<br>Reduce by 80% below 1990 levels by 2050 |
| **Quebec** | Reduce by 20% below 1990 levels by 2020 |

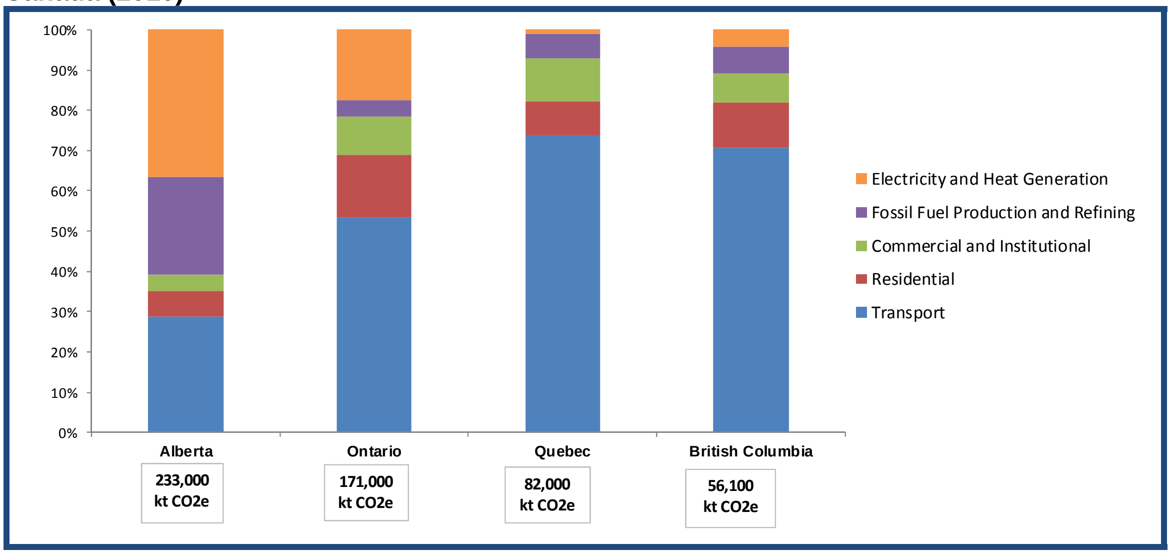
180 local governments from across BC have joined with the Province and the Union of BC Municipalities by committing to the British Columbia Climate Action Charter. The Charter pledges to significantly cut GHG emissions by 2012 through carbon neutrality. Carbon neutrality means having no net emissions of GHGs, generally achieved through

[32] British Columbia Green Economy. http://www.bcge.ca/BCs_Green_Economy_print.pdf

reducing GHG emissions where possible, by investing in projects that eliminate GHG emissions, and capturing and containing GHG emissions.

Furthermore, as Figure 32 demonstrates, the GHG emissions profile of each province is significantly different from the others.

**Figure 32. Energy Sector Related GHG Emissions Profile across Four Jurisdictions in Canada (2010)**

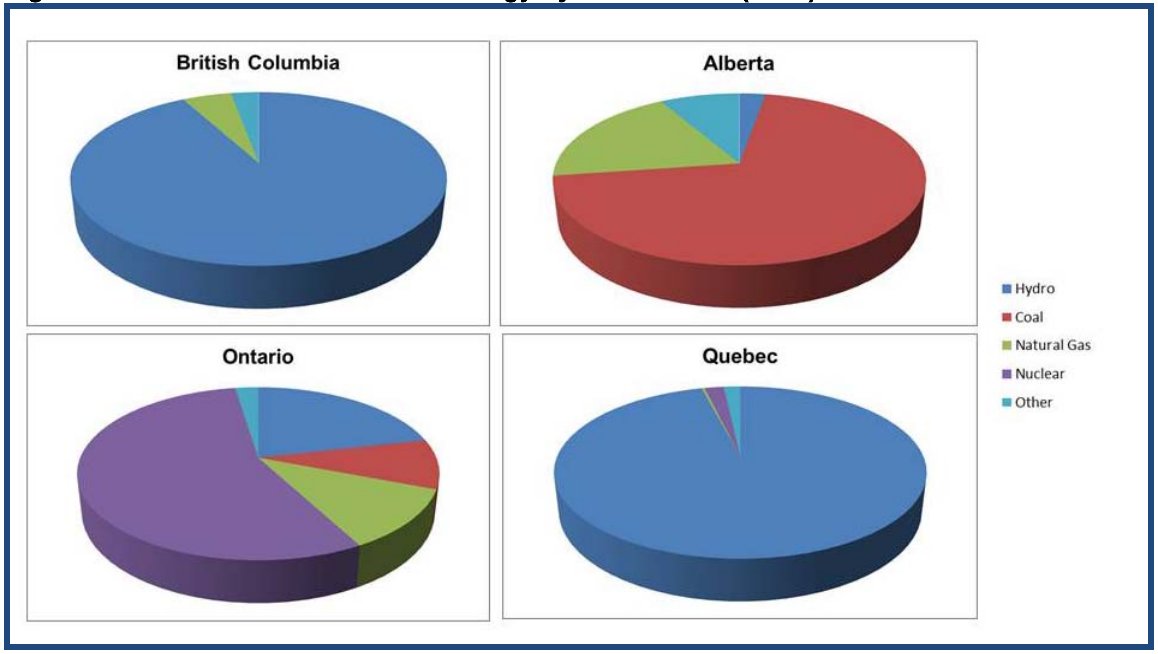



**Source:** Environment Canada National Inventory Report 1990-2010 data

Differences among the provinces in GHG emissions profile can lead to different GHG emissions reduction solutions within each province. One of the main differences among provinces relates to GHG emissions from electricity production.

The major fuel sources for electricity generation in British Columbia, Alberta, Ontario and Quebec are summarized in Figure 33.

**Figure 33. Generation of Electric Energy by Fuel Source (2010)**




**Source:** Calculations based on statistics in the Canada National Inventory Report 1990 – 2010
Alberta data from Alberta Electric System Operators 2011 Annual Market Statistics

Ontario has the most diverse electricity supply mix in Canada, with nuclear being the main source of electricity generation, followed by hydro and then natural gas. Ontario recognizes the role natural gas can play in reducing GHG emissions. It intends to continue to promote natural gas in electricity generation, by replacing coal fired plants, in the years to come.[33]

Alberta's abundant coal reserves have led to coal fired plants being a major source of its electricity generation. Despite the higher cost of electricity production resulting from the use of fossil fuels and their contribution to GHG emissions, it is expected that the government of Alberta will continue the use of local fossil fuel resources to promote economic development.[34] Shifting from coal to natural gas for electricity generation in Alberta will have the effect of reducing GHGs from electricity generation. At the same time, it is expected that natural gas will continue to be promoted in direct use applications because it is more efficient and cost effective than producing electricity from natural gas.

British Columbia and Quebec have very small amount of fossil fuel fired electric production. Instead, they have the highest hydroelectric energy output of the four provinces that have been reviewed due to abundant hydro resources available in those provinces. Given that GHG emissions from electricity generation in BC are minimal, the

[33] Ontario's Long-Term Energy Plan. Building Our Clean Energy Future
http://www.energy.gov.on.ca/docs/en/MEI_LTEP_en.pdf#page=20
[34] For example, the Alberta government's Economic Outlook in the 2012 Budget states: *"Alberta's domestic demand for natural gas is expected to grow, as expanding oil sands production depends on natural gas as a source of electricity and steam generation. Alberta demand is expected to exceed gas exports by 2013-14."*
Province of Alberta. Economic Outlook: Budget 2012 Investing in People.
http://www.finance.alberta.ca/publications/budget/budget2012/fiscal-plan-economic-outlook.pdf

province must target other areas such as the transportation sector as well as the residential and commercial sectors to achieve significant reductions in GHG emissions. Currently, the *Clean Energy Act*'s has a provision that 93% of electricity generation has to come from clean or renewable resources, thus limiting BC Hydro "in its ability to leverage this resource beyond 7% of total generation".[35]

In the 2009 ROE and Capital Structure Application, FEI identified a trend of promoting alternatives to natural gas in heating applications as a way of achieving climate objectives. In that Application, FEI filed a report entitled, "A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis," dated August 22, 2008, and prepared for the National Round Table on the Environment and the Economy by J & C Nyboer and Associates, Inc,[36] which indicated that by 2050 virtually all residential and commercial space and water heating in BC will have migrated from natural gas to electricity. The Commission further confirmed this, in Order No. G-158-09, on page 37:

> *"The Commission Panel agrees with [FortisBC Energy] that the introduction of climate change legislation by the provincial government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity. In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three [FortisBC Energy] utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers."*

The trend has solidified. Municipalities are making significant changes to their operations, policy, codes and regulations, which are having a direct impact on natural gas throughput. For instance,

- The City of Vancouver's general strategy to achieve carbon neutrality from its own operations is to use best practices to reduce emissions from civic buildings, fleet, and solid waste and to offset remaining emissions by developing incremental, verifiable GHG emissions reduction projects and programs in the local community. Reducing GHG emissions in civic buildings typically means reducing natural gas consumption.

- As part of its "green building" strategy, through introduction of new codes, regulations, and bylaws, the City of Vancouver determines the most appropriate and efficient energy source for consumption and thus encourages and discourages certain energy options. For instance, the City of Vancouver Building By-Law code compliance enforcements are estimated to reduce space heating energy use by 50 percent in all new commercial buildings and multi-family high rise buildings. Also, the Green Homes Program for construction of one- and

[35] BC Government. Review of BC Hydro. June 2011, p. 94. http://www.newsroom.gov.bc.ca/downloads/bchydroreview.pdf
[36] 2009 ROE and Capital Structure Application, Exhibit B-11, Panel 1.1, and Attachment 1.0

two-family homes includes bylaws limiting the types of gas fireplaces that are acceptable for installation.

- As a further example, the City of Surrey's City Centre District Energy System By-law requires compulsory hydronic systems[37] to be put in place that are compatible with a district energy system for all space heating and hot water heating.

These actions by local governments to promote moving away from natural gas (as the business as usual energy source) to other renewable energy sources, as well as efforts to encourage conservation and efficiency, negatively impact demand for natural gas.

## 9.3 – Carbon Tax

The carbon tax is an example of legislative or political action that has had direct implications for the price competitiveness of natural gas as an energy source in BC.

British Columbia and Quebec are the only two provinces in Canada that have implemented carbon tax policies on fossil fuels. Carbon tax discourages the use of natural gas in favour of other energy forms (i.e. clean electricity) by signaling consumers to change their behavior[38]. As shown in Table 9, British Columbia has a significant higher than Quebec. The BC carbon tax has increased from $0.50 per GJ in 2008 to $1.50/GJ in 2012. This increase in carbon tax since 2008, and since the 2009 ROE and Capital Structure proceeding has been an offset to the decline in natural gas commodity prices.

**Table 9. Provincial Carbon Tax Rate**

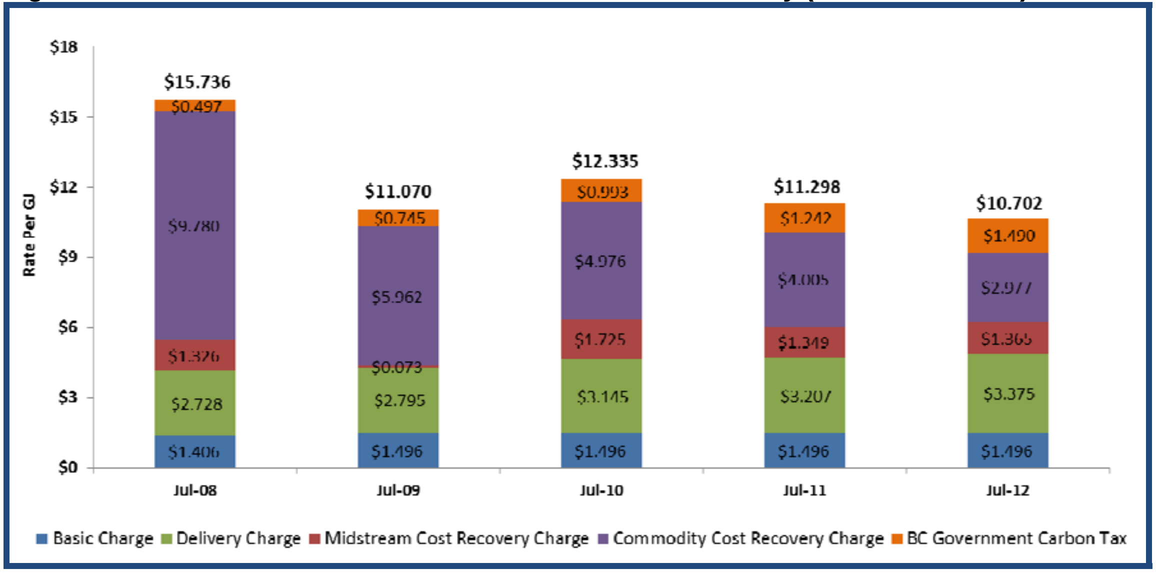
| Province | Start Date | Carbon Tax Rate |
|---|---|---|
| **British Columbia** | 2008 | $10 per metric ton of CO2e emissions in 2008, increasing $5 annually to $30 in 2012 |
| **Quebec** | 2007 | $3.50 per metric ton of CO2e emissions |

**Source:** National Renewable Energy Laboratory

The carbon tax represents a competitive challenge for FEI as it is a discrete tax applicable to natural gas and other fossil fuels, but not to electricity (despite the fact that some of the electricity that is consumed in BC is generated by fossil fuels in neighboring jurisdictions). Figure 34 provides a historical look at gas prices from July, 2008 to July 2012 for Rate Schedule 1 customers of FEI, which breaks out the carbon tax component.

[37] Hydronics is the use of water as the heat-transfer medium in heating and cooling systems. The energy used to heat the hot water can be, but not limited to, natural gas, biomass, geo-thermal, or waste water. This technology is more adaptable and as such can change the type of energy sources or the mix of the energy sources overtime r to produce the desired outcome. Therefore, these types of developments could reduce the amount of natural gas that is used overtime.
[38] Ministry of Environment, News Release: June 27, 2012, paragraph 6

**Figure 34. FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)**




The potential for carbon tax increases and the level of tax beyond 2012 remain unknown at this time. The BC government recently announced, however, that the carbon tax will be frozen after the scheduled July 2012 rate increase while the government conducts a review to determine its impact on BC's economy[39]. Given the uncertainties with potential political landscape in BC, the carbon tax review will not likely be completed until the next provincial election. In the meantime, the competitive impacts of the carbon tax persist.

## 9.4 – Aboriginal Rights

FEI continues to face a similar level of business risk related to aboriginal claims in British Columbia as articulated in the 2009 ROE and Capital Structure Application. The risk faced by FEI is greater than the risk faced by utilities in other parts of Canada.

Aboriginal peoples of Canada hold aboriginal and treaty rights that are expressly recognized and affirmed by section 35 of the *Constitution Act, 1982*. This poses risk to all utilities in Canada. However, two main factors differentiate BC from elsewhere. First, there is a larger number of First Nations and aboriginal groups in BC. Second, there is a difference in treaty status. British Columbia recognizes 285 different First Nations, Bands and Tribal Councils. The large majority of these First Nations are not signatories to a treaty (historic or modern) and most land in British Columbia is not covered by a treaty. As a result, many aboriginal land and rights claims in British Columbia remain outstanding. In addition, there can be competing claims from different First Nations over the same piece of land. In contrast, Ontario and Alberta each recognize far fewer aboriginal groups, most of which are signatories to treaties. Quebec, although not covered by treaties, also has fewer recognized First Nations. Since FEI's

[39] BC Ministry of Finance. Carbon Tax Review, and Carbon Tax Overview.
http://www.fin.gov.bc.ca/tbs/tp/climate/carbon_tax.htm

activities span large parts of British Columbia, the Company comes in contact with a large number of aboriginal groups in British Columbia.

Since 2002, in the BC Courts and the Supreme Court of Canada, there have been a number of significant court cases that have discussed when consultation is necessary and the scope of the consultation that is required. These cases deal with those situations where the Government is considering approving/permitting projects that may negatively impact on an asserted or proven Aboriginal or treaty right. In those situations, the Crown will typically owe a 'duty to consult' with affected First Nations and, depending on the strength of the aboriginal group's claim and the degree of impact, there may be a need to accommodate those Aboriginal interests. Although the duty to ensure that proper consultation has taken place ultimately rests with the Crown, in the majority of cases, the procedural aspects – that is, the actual on-the-ground work of information sharing, learning about the potential impacts and the planning for mitigation - is delegated to the project proponent. The project proponent is also affected by the pace and nature of any dealings between the Crown and the First Nation, and any court decision that halts a project for lack of adequate consultation.

FEI is directly affected by this dynamic. For instance:

- The BC Court of Appeal ruled in March 2009 that British Columbia Utilities Commission decisions could affect aboriginal rights, and that the BCUC must determine the adequacy of aboriginal consultation and accommodation before making decisions. By Order No. G-50-10, the Commission CPCN Guidelines were modified to specify that public utility CPCN applications include consideration of First Nations consultation. Since that time, FEI's project applications have had to address First Nations consultation.

- FEI must comply with the Consultation and Notification Regulation created pursuant to the *Oil and Gas Activities Act,* which prescribes a formal process for pipeline companies who are seeking Oil and Gas Commission ("OGC") permits to formally notify and/or consult with individuals or organizations that may be affected by OGC permits.

The area of aboriginal law, particularly in the area of consultation and accommodation, is evolving, with new cases being heard by the courts on a regular basis. The outcome of these cases, whether or not they relate specifically to public utilities, can have a bearing on FEI's business as they can impact Government policy and processes of permitting authorities.

The uncertainty described above regarding consultation, government process, accommodation and the undefined nature and extent of aboriginal rights and title in BC creates operational and regulatory complexity and a risk of litigation that is greater than other areas in Canada.

## 10. REGULATORY RISK

In this Section, the FBCU address regulatory risk. Ms. McShane defines regulatory risk as follows:

> *"Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in regulatory philosophy, government policies, including energy policy, and underlying fundamental business risk factors, e.g., the competitive environment."*

The discussion below focusses on general rate-setting, regulatory uncertainty, regulatory lag, deferral accounts and administrative penalties.

### 10.1 – Regulatory Approvals

FEI, as a public utility in BC, is subject to oversight by the Commission. The Commission acts pursuant to its powers under the *Utilities Commission Act* ("*UCA*") but within that framework has significant discretion in the exercise of those powers. FEI is dependent on regulatory approvals that determine its revenue requirements and cost of service recovery and approve investments. The Commission establishes the level of return that is allowed to be included in rates. This regulatory oversight gives rise to the risks that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn the allowed return, or that necessary investments are not approved.

### 10.2 – Regulatory Uncertainty and Lag

In recent years, the role of the Commission is transitioning from that of a purely economic regulator to one that increasingly considers and implements public policy. For instance, there are requirements for Commission to consider British Columbia's energy objectives within the *CEA* when it reviews long term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts under the *UCA*. In FEI's view, there remains some uncertainty regarding how Government's intentions are to be reflected in regulatory decisions, and these requirements are often debated in regulatory proceedings. The expansion of the Commission's role has coincided with the development of a number of new initiatives by FEI. There have been a number of decisions on these initiatives, and intervening pronouncements from Government, such that the final direction on some important business issues for FEI remain unclear (of particular relevance in the context of assessing business risk is NGT).

The growing complexity of FEI's operating environment, in tandem with the growing number of approvals required, can also lead to delays ("regulatory lag") in system investments, or the delivery of service offerings. A notable example is the NGT service offering, which was first proposed in June 2009, but is still being assessed in various proceedings.

## 10.3 – Deferral Accounts

FEI continues to employ Commission-approved deferral accounts. In recent years, there have not been significant changes to deferral accounts and the key deferral accounts have been in place for some time[40]. The Commission determined in the 2009 ROE Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]...".[41]

The majority of the deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the Company. Deferral accounts can help to reduce the rate impact and rate volatility for customers. Table 10 summarizes the general categories of FEI's deferral accounts.

[40] Exhibit B-1-3, FEU 2012/13 RRA, pages 420 - 422 as updated September 28, 2011, outline changes to deferral accounts in 2012 and 2013. Of 12 new accounts, three pertain to application costs, three pertain to the approved transition to US GAAP, two represent accounts that have been segregated or combined from existing accounts, and two pertain to projects proposed in the application for Asset Records and BCOneCall. Of the remaining two accounts, one reflects uncertainty regarding requirements and potential recoveries associated with emissions regulations (Compliance to Emissions Regulation account) and the other is a variance account for some aspects of customer service operating costs (Customer Service Variance account). 2012 is the first year of operation for the recently insourced customer contact centre and the operating of the customer information system.

[41] Order No. G-158-09, page 19

**Table 10. Deferral Accounts**

| Deferral Account Category | General Purpose & Description |
|---|---|
| **Margin Related** | • Decreasing the volatility in rates caused by such factors as fluctuations in commodity prices and the significant impacts of weather on use rates<br>• Deferring the cost of gas and delivery margin impacts arising from un-forecast variations in these types of factors and recovering them from/refunding them to customers over a longer period of time is an effective method of reducing rate volatility<br><u>Examples:</u> Commodity Cost Reconciliation Account ("CCRA"), Midstream Cost Reconciliation Account ("MCRA") and Revenue Stabilization Adjustment Mechanism ("RSAM") |
| **Energy Policy** | • Capturing costs associated with changing energy policies that focus on energy efficiency, conservation and the environment<br>• Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers<br><u>Examples:</u> Energy Efficiency and Conservation Account ("EEC"), Compliance with Emissions Regulations, NGV Incentives |
| **Non-Controllable Items** | • Items which are either outside of the Company's control or where the Company has limited ability to influence the costs<br>• Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers<br><u>Examples:</u> Property Tax Variance, Insurance Variance, BCUC Levies Variance |
| **Deferred Costs of BCUC Applications** | • Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous other costs<br><u>Examples:</u> 2012-2013 Revenue Requirement Application Costs, Long Term Resource Plan Application Costs |
| **Other** | • Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature<br><u>Examples:</u> Whistler Pipeline and Conversion Costs, BCOneCall Project, Gas Asset Records Project |

## 10.4 – Administrative Penalties

On May 31, 2012, Bill 30 – *Energy and Mines Statutes Amendment Act*, 2012 – received Royal Assent. Bill 30 amends several statutes, including *Clean Energy Act*, *Oil and Gas Activities Act* ("*OGAA*") and *UCA*. Both amendments to the *OGAA* and *UCA* can have impact on FEI's operation, with potentially the most significant impact resulting from amendments to the *UCA*.

The amended *UCA* gives the Commission the authority to impose administrative monetary penalty against a public utility in the event that the utility is found to have contravened a provision of the *UCA*, the regulations, or a Commission order or rule. This represents a significant change to the former provisions of the *UCA*, under which a contravention by the utility of a *UCA* provision or a Commission order or rule constituted an offence, subject to prosecution in a court system. The amended provisions make an employee's contravention attributable to the utility corporation and make the corporation's officers and directors potentially personally liable if they have "authorized, permitted or acquiesced" to the contravention.

Although the amended provisions regarding the Commission's authority to impose administrative penalties have not come into effect yet, these added administrative penalty provisions could have consequences for FEI's operations and ultimately increase FEI's business risk.

## Appendix I

# EVIDENCE OF CONCENTRIC ENERGY ADVISORS INC.

CONCENTRIC ENERGY ADVISORS

# Fortis BC Utilities

# A Review of Automatic Adjustment Mechanisms for Cost of Capital

# Update and Recommendations

August 3, 2012

Table of Contents


SUMMARY ........ 1

1. Introduction and Background ........ 1

2. Recent Developments in Formulaic Approaches to Estimating Allowed Equity Returns ........ 2

   a. Canadian Jurisdictions ........ 2

   b. U.S. Jurisdictions ........ 4

3. Formulaic Adjustment Mechanism Design Considerations ........ 7

   a. Design Criteria ........ 7

   b. Importance of the Starting Point ........ 8

   c. Formula Parameters ........ 9

   d. Relevance to Current Economic Conditions ........ 10

   e. Pitfalls ........ 10

4. Potential Approaches ........ 11

   a. Enhanced Ontario Formula ........ 11

   b. Combined Ontario and Average Awarded ROE Index ........ 11

5. Conclusions ........ 12

Attachment A ........ 14

## SUMMARY

In this report we update our previous analysis, *A Review of Automatic Adjustment Mechanisms for Cost of Capital* (November, 29, 2010) (the "2010 Concentric Report"), which surveyed the prevalence of cost of capital formulas in North America. In addition, we provide our recommendation for the most appropriate method for setting the cost of capital for the benchmark utility, FortisBC Energy Inc. ("FEI"), on an ongoing basis.

In the 2010 Concentric Report, we researched and evaluated alternative ROE automatic adjustment mechanisms. In doing so, we primarily examined formulas used in North American jurisdictions and also researched selected overseas jurisdictions and considered other alternatives. Though Concentric did not recommend a formulaic approach, we did identify attributes to be considered should the Commission determine that a new formula be adopted in BC. Those attributes are recapped in Section 3 of this Report. Further, we examined alternative inputs and parameters used to construct formulas and compared how formulas perform over time against non-formulaic results and under varying market conditions. Based on this assessment, we identified four potential options for a formulaic adjustment mechanism, and a fifth option, periodic rate hearings. The formulaic approaches varied in terms of their complexity and ease of administration.

Based on our analysis and assessment of those options, we conclude that all formulaic approaches run the risk of deviation from a fair return. Fluctuations in financial markets are inevitable, and relationships between bond and utility equity securities cannot be fully anticipated by historical relationships, leading formulaic Automatic Adjustment Mechanisms ("AAM") results to deviate from required equity returns. Consequently, periodic rate hearings remain the only reliable method for determination of utility ROEs.

## 1. Introduction and Background

In the British Columbia Utilities Commission's ("BCUC" or the "Commission") Return on Equity and Capital Structure Decision dated December 16, 2009, the Commission found:

> A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.
>
> The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.[1]

[1] BCUC Decision, G-158-09, (December 16, 2009) at 73.

Pursuant to the Commission's Decision, Concentric assisted FEI (formerly Terasen Gas Inc.) with the development of a study of alternative formulas for determining the cost of capital, filed with the BCUC on December 8, 2010. Subsequent to that filing, the BCUC issued Order G-20-12 on February 8, 2012, initiating a generic cost of capital ("GCOC") proceeding.

In the Minimum Filing Requirements to the GCOC proceeding, the Commission requested evidence on the following question: "Should the Commission return to a formulaic approach to setting a benchmark ROE and if so, what should the formula be and for what period of time?"[2] In response, FortisBC Utilities ("FBCU") engaged Concentric to address the effectiveness of AAM and to assist the Companies in responding to the Commission's question. In this Report, Concentric:

1. Provides updates to our Report for recent developments in cost of capital formula used in other jurisdictions in Canada and the U.S.;
2. Recaps the principal attributes that should be considered if an automatic adjustment mechanism is used to estimate utility return on equity;
3. Addresses the sensitivities around using an AAM in the context of current economic conditions; and
4. Concludes with recommendations regarding the preferred approach to setting ongoing ROEs for the Province's utilities.

## 2. Recent Developments in Formulaic Approaches to Estimating Allowed Equity Returns

### a. Canadian Jurisdictions

By the time of Concentric's 2010 Report, the Canadian landscape for estimating ROE using the AAM had undergone significant scrutiny and change by way of rate applications and generic cost of capital proceedings. Table 1 contains a summary of what has transpired in the major Canadian regulatory jurisdictions relative to the AAM since our 2010 Report.

As is evidenced in this update, Ontario and Quebec now remain the only jurisdictions currently reliant on a formulaic approach.

**Table 1**

| Regulator | Status as of 2010 Report | Status at Present | Relevant Order |
|---|---|---|---|
| British Columbia Utilities Commission (BCUC) | Suspended | GCOC Proceeding | TBD |
| National Energy Board (NEB) | Terminated | Unchanged | Not Applicable |
| Public Utilities Board of Manitoba (PUBM) | Terminated | Unchanged | Not Applicable |
| Ontario Energy Board (OEB) | Modified | Unchanged | Not Applicable |
| Newfoundland and Labrador Board of Commissioners of Public Utilities (NL PUB) | Maintained | Suspended | P.U.17 (2012) |
| Quebec Régie de L'Énergie (Régie) | Maintained | Modified | D2010-147/ D2011-182 |

[2] BCUC Order G-50-12, Appendix B, page 3 of 5.

| | | | |
|---|---|---|---|
| Alberta Utilities Commission (AUC) | Suspended | GCOC – Maintained Suspension | Decision 2011-474 |

Highlights of these developments include the following:

- The NEB terminated its reliance on a formulaic AAM in October 2009, and has not reconsidered its decision.

- The Public Utilities Board of Manitoba abandoned the use of the AAM, and this remains unchanged.[3]

- In December 2009, the Ontario Energy Board rebased and modified its AAM from a simple reliance on 75% of the change in the Canada Long Bond to 50% of the change in forecast long-term Canada bond yields and 50% of the change in observed A-rated utility bond index over the 30-year Canada Bond yield. The OEB continues to rely on its modified formula.[4]

- In Newfoundland and Labrador, Newfoundland Power requested in March 2012 that the Commission discontinue the use of a formulaic ROE:

  > The Application's focus is the ratemaking return on equity to be included in establishing a just and reasonable return on rate base. Neither the ratemaking return on equity of 7.85% for 2012 indicated by the automatic adjustment mechanism used to establish a return on rate base for the Company (the "Formula") nor the ratemaking return on equity of 8.38% currently included in the Company's return on rate base on an interim basis are appropriate. Neither meets the fair return standard because they are too low.

  A settlement agreement with an 8.8% ROE was submitted to the Board on June 5, 2012. The Board approved the 8.8% ROE (which was not set using a formula) on June 15, 2012. In its Order, the Board stated that the 8.8% was within a range of reasonable values, but does not go so far as to disavow or abandon the formulaic approach for future rate proceedings.[5]

- In Quebec, through rate proceedings first in Gazifere (D2010-147) and later in the case of Gaz Met (D2011-182), the Régie modified its previous formula to incorporate 50% of the change in utility bond spreads in addition to the existing formula's 75% of change in government bond yields. The Régie set Gaz Metro's return on equity for 2012 based on the evidence in that proceeding, and concluded that for a three-year period commencing in 2013

---

[3] The Manitoba Commission no longer uses the formula to make ROE determinations, but still uses the formula as a reasonableness check for return determinations for Centra Gas. See Manitoba Board Orders 103/05 and 115/05, (October 2005), part 1.(a), at 3 "regulatory approach alternatives – the Board confirms its intention to use both the Rate Base Rate of Return and Cost of Service methodologies, with Rate Base Rate of Return to be a test of the maximum allowable return to MH."

[4] Ontario Energy Board, *Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*, March 2, 2012.

[5] Newfoundland & Labrador, Board of Commissioners of Public Utilities, Order No. P.U. 17(2012), June 15, 2012.

the new formula, which adjusts for credit spreads in its second parameter, would be employed.[6]

- In Alberta, the AUC established a generic cost of capital proceeding to set ROE for its affected utilities for 2011 and to consider whether it should reintroduce a formula by which ROE would be adjusted on an annual basis beyond 2011. In its consideration of potential alternative formulas, the Commission noted that all parties to the proceeding had found that a formula that incorporated both changes in government bond yields and changes in utility bond spreads was preferable to the previous formula's sole reliance on government bond yields (similar to what had been determined in Ontario and Quebec).[7]

  When reflecting upon its rationale for discontinuing the formula, the Alberta Commission stated it had "found that in times of adverse market conditions, the expected relationship between interest rates and the required return on equities does not necessarily hold."[8] Though the evidence in the case recognized that financial markets had improved since the formula was discontinued in 2009, it was determined that credit markets still remained volatile. As a result, the AUC decided not to employ an adjustment formula for 2012, but indicated that it "was not prepared to preclude a return to some form of formula-based adjustment mechanism in the future, once the capital markets [had] stabilized and [were] once again considered reasonably predictable."[9] Instead, the AUC authorized a generic return for its regulated utilities for 2011 and 2012 and additionally set an allowed ROE for 2013 on an interim basis. The Commission plans to initiate a proceeding to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a going forward basis.[10]

- Finally, we note that PEI considered but rejected adoption of a formulaic approach in its decision regarding the appropriate rate of return for Maritime Electric Company:

  > The Commission did not adopt a formula approach to ROE during a period of time when such an approach was used by regulators as the standard for setting ROE. The Commission sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated. Judgment, taking into consideration comparators, current market conditions, and appropriate risk assessment, are also very relevant.[11]

### b. U.S. Jurisdictions

In the 2010 Concentric Report, we noted that few U.S. regulatory jurisdictions had adopted formulaic approaches to determining ROE. In the vast majority of jurisdictions, the use of periodic

6 Régie de l'Énergie, Decision D-2011-182/File R-3752-2011, English Version, Section 4.3 – Rate of return (November 25, 2011).
7 Alberta Utilities Commission Decision 2011-474, 2011 Generic Cost of Capital, December 8, 2011 at 164.
8 Ibid at 163.
9 Ibid at 166.
10 Ibid at 305.
11 The Island Regulatory and Appeals Commission, Docket UE20940, Order UE10-03, July 12, 2010, p. 22.

rate cases is the approach used for setting rates and ROE. Stakeholders typically present updated capital market information and ROE estimates from several models (e.g., DCF, CAPM, Risk Premium, etc.). A range of competing estimates from witnesses is not uncommon, providing regulators with some latitude to weigh the evidence. Utilities typically have the discretion to "stay out" for one or more years between rate cases, but regulators can require the utility to file an updated cost of service if they deem rates unfair. As a result, multi-year ROE determinations are common in many jurisdictions, creating some of the administrative efficiency sought through formulas.

Of those jurisdictions that employ a formulaic approach, practices range from prescriptive to simplistic. The prescriptive approach lays the ground rules for conducting an ROE study using standard methodologies and inputs, but does not narrow to a specific mathematical formula. For example, FERC's prescribed ROE model for electric utilities specifies a DCF method utilizing a combination of high and low analyst growth rates and a sustainable growth input, designed to produce a range of high and low results along with a median and mean. Parties to these proceedings have some flexibility in determining the appropriate proxy group and recommending where in the range a given utility or transmission facility should fall for ROE. A prescriptive approach has been employed in Mississippi and considered in New York and more recently in Connecticut.

The simplistic approach utilizes a formula, much like the former BC AAM, and is tied to one or two data inputs. Vermont and California use simplistic formulas tied to bond yields. Table 2 summarizes developments in U.S. jurisdictions since the drafting of the 2010 Report with respect to the AAM. The only state to recently adopt a formula is Illinois.

**Table 2**

| Regulator | 2010 Report | Present | Relevant Order |
|---|---|---|---|
| Vermont Public Service Board (VPSB) | Maintained | New VGS Proposal | Pending |
| California Public Utilities Commission (CPUC) | Maintained | Requested Off-Ramp | Ongoing |
| Mississippi | Maintained | Unchanged | Not Applicable |
| Connecticut Department of Public Utilities Control (CT DPUC) | Under Review | Case Closed w/o Decision | 09-10-06 PURA:RL |
| Illinois Commerce Commission (ICC) | No Formula | AAM | Illinois Act 097-0646 |

Highlights of these developments include:

- In Vermont, Vermont Gas recently proposed an ROE formula with a 50% sensitivity to changes in 10-year Treasury bond yields. Additionally, Green Mountain Power and Central Vermont Public Service continue to operate under each company's respective Alternative Regulation Plans until they expire in 2013, which have similar formulas for determining ROE.[12]

[12] RRA SNL Database Vermont Commission Profile, *also see* VPSB Order, Docket 7627 (March 3, 2011).

- The California utilities file cost of capital applications every three years. The most recent full cost of capital proceeding was filed in April 2012 for the test years 2014-2016. The intervening periods are governed by the Capital Cost Mechanism ("CCM") which is tied to the variation of corporate bond yields, based on each company's corporate credit rating. During the intervening years, the utilities are required to file a Tier 2 advice letter on October 15 of any year when the difference between the current 12-month October through September average utility bond rate and their respective interest rate benchmark exceeds a trigger of 100 basis points. If triggered, the utilities' return on equity for the following calendar year is automatically adjusted by one-half the difference between the current average utility bond rates and their benchmarks.[13] In San Diego Gas and Electric's most recent filing from April 20, 2012, the company sought a revised baseline of 11.0%, but did not request any significant modifications to the CCM. The company did, however, request that an off-ramp option be available in the event that bond prices become particularly volatile. It involves a provision that allows SDG&E to voluntarily suspend the CCM should the yield on single-"A" rated utility bonds move by more than 250 basis points from the benchmark during the record period.[14]

- There have been no major base rate cases in Mississippi in several years, as Mississippi utilities continue operating under formula-based alternative rate plans. Atmos Energy's Mississippi Division has been operating under a gas alternative rate plan since 1992. The most recent performance-based benchmark return on equity calculated under Atmos' alternative rate plan is 10% (for test-year 2011).[15]

- In Connecticut, on December 23, 2009, the Department of Public Utility Control ("DPUC") issued a Notice of Request for Written Comments to explore the need, desirability and feasibility of establishing a uniform methodology for determining return on equity for public service companies. In its notice, the DPUC issued a description of several elements that might form the basis of a uniform methodology for determining return on equity and requested comments from public service companies, the Attorney General of the State of Connecticut, the Office of Consumer Counsel and other interested parties regarding this area of inquiry. The proceeding was closed on May 9, 2012 without a final order. According to the letter closing the docket:

  > At this time the Authority finds it in the public interest to close this docket without issuing a Decision since the main goal of the instant proceeding has been fulfilled by written comments and dialogue among the participants which has produced a better understanding of the inputs to the determination of an allowed ROE in a rate case format. This better understanding of the various ROE methodologies will be reflected in future rate cases.[16]

---

[13] Decision 09-10-016, Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008 (October 15, 2009).
[14] Cost of Capital Application of San Diego Gas & Electric Company (U902M) (April 20, 2012) at 9.
[15] RRA SNL Database, Mississippi Commission Profile.
[16] Letter re: Docket No. 09-10-06 – Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (May 9, 2012).

Parties to the proceeding were unable to achieve consensus on a formulaic approach to ROE, and none was adopted.

- In Illinois, Senate Bill 1652 was signed into law on Dec. 30, 2011. The law was primarily directed at a net-metering/smart metering initiative, but also included formula rate plan provisions for Commonwealth Edison and Ameren Illinois. The formula rate plan determines the allowed return on equity that is applied to the prior year's results; a 580 basis-point premium (590 basis points for the first "reconciliation" only) is added to the 12-month average 30-year Treasury bond yield. If the utility's actual ROE in a given period is more than 50 basis points above or below its authorized ROE, the company is required to refund/collect from ratepayers any amounts outside of this deadband. In addition, the utility's allowed ROE may be reduced if it fails to meet certain performance metrics.[17]

## 3. Formulaic Adjustment Mechanism Design Considerations

### a. Design Criteria

In the 2010 Concentric Report, we identified nine attributes to be considered in developing an AAM. This section provides a recap of those attributes, with additional detail provided in our 2010 Report. Concentric is of the opinion that any formulaic approach selected should give adequate consideration to these criteria:

1. Tracks required utility equity returns
2. Easily administered
3. Based on commercially accessible inputs
4. Promotes regulatory transparency
5. Forward-looking
6. Exhibits stability
7. Insulated from the effects of anomalous and transitory market conditions
8. Includes a specified timetable for periodic review and/or rebasing of the formula
9. Reflects the capital market conditions faced by the utility

<u>Tracks Required Utility Equity Returns</u> - The formulaic approach must accurately reflect investor required equity returns amid varied economic and financial market conditions.

<u>Ease of Administration</u> - Any formula established should be readily administered by regulatory staff without the assistance of outside experts.

<u>Based on Commercially Accessible Inputs</u> - Formulas should utilize data that is commercially available for both U.S. and Canadian companies.

<u>Promotes Regulatory Transparency</u> - Regulatory transparency refers to the openness of the process and predictability of outcomes by all stakeholders, i.e., the utility, creditors, investors, and ratepayers. A formulaic ROE that can be readily estimated by stakeholders promotes regulatory transparency, enabling investors to make forward projections based on widely understood data inputs.

[17] SNL Database, RRA, Illinois Commission Profile *also see* Illinois Public Act 097-0646, HB3036 Enrolled.

Forward-Looking - A formulaic ROE should provide an informed estimate of what investors will require in returns over the course of the applicable rate-setting period. For this reason, the use of yield projections and share price data are beneficial in providing a forward looking view of what is to come on the investment horizon. Near-term historical data may be a reasonable proxy for projected data unless significant growth or anomalous market activity render recent history an inappropriate indicator for the projection period.

Stability - The formula should be responsive to changing market conditions but not overly sensitive to normal market volatility. It should have the stability to moderate the effects of temporary market movements so that regulators and utilities alike are not constantly making nominal changes to rates that would otherwise reverse themselves in the next period. Deadbands are often employed for this purpose. A formula that is too sensitive to market volatility introduces unnecessary volatility to utility revenues and rates and results in inefficient rate revisions.

Insulated from the Effects of Anomalous and Transitory Market Conditions - Some formulaic approaches employ ceilings and floors to limit the movement of ROE from starting levels and/or trigger a review. Once such a condition is indentified, there must be an assessment and resolution process where the regulator and stakeholders arrive at an equitable solution for ensuring the fair return on equity for the upcoming period.

Specified Timetable for Periodic Review and/or Rebasing of the Formula - Any formulaic methodology should be accompanied by defined conditions that would trigger a review. It is necessary to routinely benchmark the formulaic result to other measures of ROE. Concentric recommends an established framework for rebasing the formula, i.e., every three to five years, unless there is substantial agreement among stakeholders that the formula is providing reasonable results. The periodic review, at a minimum, should incorporate tests beyond those upon which the formula is based. There is also value in allowing parties to seek a review of the formula when and if they believe it is providing unreasonable results.

Reflects the Capital Market Conditions Faced by the Utility - When setting the ROE for a regulated utility, it is important to obtain data inputs reflecting capital market conditions faced by the utility. The integration of North American capital markets and the similarity of the legislative and regulatory processes have created a more homogenous market for utility capital. Regulators adopting formulas should choose proxies carefully, so that risks borne by the proxy companies are representative of those to which the utility under consideration is subjected. Though no proxy is perfect, risk adjustments may be made for marked differences in risk profiles between the utility and its set of proxy companies.

### b. Importance of the Starting Point

Assuming the BCUC determines a formula should be adopted, care must be exercised in establishing the initial ROE, as the effects of any understatements or overstatements will be felt with each succeeding application of the formula. Concentric is of the view that the initial ROE should be set in accordance with traditional ROE setting methodologies, utilizing multiple approaches based on a proxy group of companies with similar risk profiles in a process where the regulator considers evidence from the company and its stakeholders. Most jurisdictions go through this process each time ROE is set. A regulatory process where stakeholder evidence is presented and considered by the commission generally provides a sound basis for a fair determination of ROE.

A fair starting point promotes objectivity in setting the parameters of the AAM. Ultimately, any formula that is based on incorrect parameters will lead to more not less regulatory inefficiency, and ultimately serves to undermine the foundation and purpose for adopting an AAM formula, i.e., regulatory expediency and a fair result. For these reasons, it is best to first settle on a rebased result that is fair before setting out the parameters and methodologies of a proposed AAM.

### c. Formula Parameters

When utilizing an AAM, data inputs and parameters of the formula must be carefully selected. Otherwise, errors will have a compounding influence on the formulaic result as they accumulate over time. The components of a cost of capital or ROE adjustment formula can be broken down into two fundamental functions.

First, the inputs should be selected to approximate the movement of ROEs required by utility investors. The 2010 Concentric Report identified the following inputs and coefficients that are present in the ROE automatic adjustment mechanisms researched:[18]

- Forecast Government Bond Yield
- Historical Government Bond Yield
- Corporate Bond Yield
- Utility Bond Yield
- DCF, Risk Premium and CAPM Inputs
- Formula Coefficients

There is no guarantee that any combination of these inputs and parameters will successfully track equity returns. Government and corporate bond yields have been attractive for use as inputs in an AAM due to their relative availability and transparency. However, as we have seen over the past several years, bond yields may deviate from equity returns. The NEB, AUC, and BCUC have all acknowledged this fact. Factors such as monetary and government policy and the preferences and risk tolerances of investors can significantly alter the relationships between the required returns on bond and equity securities.

Second, some formulas incorporate protective mechanisms that mitigate the impact of the formula under certain conditions. Examples of these are trigger mechanisms that prompt a review if a predetermined threshold is met, and predetermined periods for rebasing ROE. Some formulas employ ceilings and floors that are either fixed or tied to a variable, which provide a figurative rail to keep the formula returns on track. Other mechanisms may specify a materiality threshold for adjustment and employ a deadband in which no adjustment is made. Below we have recapped the list of measures identified in the 2010 Report that moderate or rebase the results of the formula in certain conditions:[19]

---

[18] 2010 Concentric Report, p. 11.
[19] 2010 Concentric Report, p. 12.

- Deadband
- Ceilings and Floors
- Trigger Mechanisms
- Review Period

### d. Relevance to Current Economic Conditions

As we observed during the 2008-2009 financial crisis, a formula that is heavily weighted on a single factor may be unduly influenced by market events. During the financial crisis and economic recession, credit spreads widened significantly and equity market volatility rose to unprecedented levels, ultimately causing government bond yields and corporate capital costs to move opposite to one another despite a historical positive relationship. Neither bond yield (government or corporate) provides a complete picture of required equity returns. Common equity holders are exposed to higher risk than bond holders, and both classes of investment are subject to market circumstances (e.g., the flight to safety lowering government bond yields) that may impact that security but not the other. However, incorporating the corporate credit spread into the AAM does mitigate the impact of changes in the relationship between corporate and government bond yields. Further, incorporating factors that estimate required utility equity returns or incorporating returns allowed in other jurisdictions into the formulaic adjustment mechanism adds additional assurance that one factor, subject to influences unrelated to utility cost of capital, would not be able to hijack the formulaic allowed return. An AAM should be sufficiently robust to function in varied and extreme market conditions.

### e. Pitfalls

There are several fundamental challenges associated with the design and implementation of an ROE formula. Foremost among these is the dynamic nature of financial markets. Formula parameters are typically static and based on historic relationships. Those fundamental relationships may shift, leaving the formula out of touch with current market conditions. Nowhere has this been more evident than with the evolution of steadily lower government bond yields over the past decade, in a shifting relationship with equity markets.

Another challenge for formulas is the potential change in equity costs for the benchmark utility in relation to the broader industry. Specific market or financial conditions affecting the utility may not have the same impact more broadly. A sharper economic downturn or growth in the service area, for example, may change the cash flow and credit quality of the benchmark utility, or the company's risk profile may change, requiring additional care in the setting of ROE. Regulators can respond to these circumstances, but a formula may produce suboptimal results for a sustained period. Setting the required return is a matter of both analysis and judgment, both of which are circumscribed during the formula period.

A related consideration is the statutory responsibility to meet the fair return standard. The foundations of public utility regulation call for the allowance of a fair rate of return that is sufficient to attract needed capital at reasonable rates, offer returns commensurate with investments of similar risk, and sufficient to maintain the financial integrity of the firm. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide regulated utility services. In turn, investors look to regulators to provide a compensatory return. While simple on the surface, the fairness standard requires a significant degree of analysis, market information, and judgment in its implementation. In Concentric's view, design of a formula that ensures compliance with the fair return standard over time has yet to be accomplished.

## 4. Potential Approaches

In our 2010 Report, we examined alternative inputs and parameters used to construct formulas and compared how these formulas perform over time against non-formulaic results and under varying market conditions. We conducted a backcast analysis on nine alternative formulas and stress-tested six of those alternatives under varying market conditions. Based on that assessment, we identified four formulaic specifications and periodic rate proceedings as potential options. The following summarizes Concentric's assessment of those options, with emphasis on the primary choice between a formulaic or rate case approach, and the ability of these approaches to meet the design criteria and principles delineated in the prior section.

### a. Formula

Regulators across Canada have recognized that ROE cannot be reliably estimated through simple relationships to government bond yields. In response, provincial regulators and the NEB have either abandoned the formulaic approach or adjusted the formula. The revised Ontario formula uses forecast government bond yields while also incorporating utility bond spreads (over government bonds). Quebec has adopted a similar approach. Incorporating a term for the credit spread between the utility bond and the long Canada bond yield may mitigate one fatal weakness in the legacy formula: sole reliance on the variable Canadian long bond yield. We view this methodology as preferable to the prior models relying solely on government bond yields. A remaining concern we have with the revised Ontario formula is the lack of any specific link to the cost of equity, other than that conveyed by bond yields. To address this issue, Concentric recommended a potential alternative including an index of authorized U.S. and Canadian ROEs as a proxy for required equity returns. This approach has an advantage relative to the new Ontario formula of including a link to equity costs. Deviations from a fair return over the formula period could still occur, however, with differences in bond yields and average allowed returns that do not match the required return for the benchmark utility. In any event, if the Ontario formula were to be considered by the BCUC, we would recommend the formula be reviewed every three to five years.

### b. Periodic Rate Proceedings

Concentric's research indicates most North American jurisdictions do not rely on a formula for setting the utility cost of capital. Cost of capital is typically set during the course of litigated rate proceedings, where company and stakeholder witnesses present independent estimates and the Commission weighs the evidence and determines the fair ROE. Within this approach, several variations are possible:

- Fixed schedule for reset - typically coinciding with a fixed rate application schedule (e.g., annually, bi-annually, etc.);

- Request of the parties - the utility, Commission, or stakeholders may request a rate hearing, including cost of capital, as changed circumstances warrant; and/or
- Settlement - the parties may agree to hold rates fixed for a certain period of time, including cost of capital, unless unforeseen market circumstances cause a re-hearing.

The advantage of this approach is its adaptability to changing market conditions, the periodic input from stakeholders, and the ability of the Commission to act on updated capital market information. Generally, ROEs are not volatile over time, and in the case of many utilities, periodic rate hearings provide a sufficient response to changing market conditions while retaining stability and predictability in returns. Drawbacks include the additional resources required for litigated cost of capital proceedings, the potential politicization of ROE by stakeholders when other rate pressures emerge, and the potential for companies to remain out of hearings when costs are decreasing.

### c. Evaluation

The relative merits of the alternative approaches may be evaluated with respect to the design criteria and principles outlined in Section 3. In favor of the formula: it is generally easily administered, based on commercially accessible inputs; promotes regulatory transparency; and may include a specific timetable for review and rebasing. In favor of a periodic rate proceeding: it is more likely to track required utility equity returns, generally based on commercially accessible inputs; is forward-looking; exhibits stability; is appropriately responsive to transitory market conditions; may include a specific period for review; and reflects the capital market conditions faced by the utility.

Some key distinctions emerge from these comparisons. Of importance, only periodic proceedings are more likely to track required utility equity returns and reflect the capital market conditions faced by the utility. While the benefits of a formula are worth consideration, the allowed ROE must track required utility equity returns and reflect the capital market conditions faced by the utility in order to satisfy the fair return standard. These are not optional.

There are several fundamental challenges associated with the design and implementation of an ROE formula. Foremost among these is the dynamic nature of financial markets that are difficult to capture in a static model. Another challenge for formulas is the potential change in equity costs for the benchmark utility in relation to the broader industry. A related consideration is the statutory responsibility to meet the fair return standard. Setting the required return to meet the standard is inevitably a matter of both analysis and judgment, both of which are circumscribed when a formula is in use.

## 5. Conclusions

In this report we have updated our survey of ROE formulas utilized in North American regulatory jurisdictions. In Canada, only two provinces remain on a formula (Ontario and Quebec). In the U.S., four states have adopted formulaic approaches (California, Mississippi, Vermont, and Illinois). As previously reported in our 2010 Report, Virginia and Florida utilize formulas to establish a range of reasonableness for ROE, as does the FERC with its prescribed ROE methodology. The experience with ROE formulas to date has been mixed. In Canada the model adopted by many jurisdictions tied to the government long bond failed to produce fair returns as the relationship between the cost of utility equity and the cost of government debt diverged over time.

The majority of jurisdictions in both Canada and the U.S. set ROE in the context of periodic rate cases. Regulators have apparently accepted that the efficiency of a formula does not outweigh the benefits of applying analysis and judgment to the determination of ROEs. Most jurisdictions rely on multiple methods and multiple witnesses to sort through the range of assumptions and results to reach a conclusion on a fair return. While formulas offer a potentially attractive alternative to this process, AAMs have yet to prove a reliable substitute for periodic rate reviews.

We conclude that there are several fundamental challenges associated with the design and implementation of an ROE formula. Foremost among these is the dynamic nature of financial markets that are difficult to capture in a static model. Another challenge for formulas is the potential change in equity costs for the benchmark utility in relation to the broader industry. A related consideration is the statutory responsibility to meet the fair return standard. Setting the required return to meet the standard is inevitably a matter of both analysis and judgment, both of which are circumscribed during the formula period.

In the current proceeding, the Commission directed the Affected Utilities to address the question: "Should the Commission return to a formulaic approach to setting a benchmark ROE and if so, what should the formula be and for what period of time?" Concentric ultimately concludes that periodic rate case determinations remain the method most likely to produce fair returns over time under varied market circumstances. If the BCUC deems it appropriate to reintroduce a formula, Concentric recommends that the Commission make its determination in consideration of the design criteria presented in Section 3 of this report.

**James M. Coyne**
**Senior Vice President**

---

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the power and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy, capital costs, valuation, fuels, and power markets. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and jurisdictions in Alberta, British Columbia, California, Connecticut, Massachusetts, New Jersey, Ontario, Maine, Texas, Vermont, and Wisconsin. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

---

## REPRESENTATIVE PROJECT EXPERIENCE

### Expert Testimony and Litigation Experience

- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 - )
- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)

- FortisBC Energy Inc., provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District, provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board' policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values.
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)

- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

**Regulatory Support Experience**

- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2011)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)

- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

**Financial and Economic Advisory Experience**

- Advisor to a major international corporation in the strategic evaluation of the SmartGrid related business segments, and development of specific investment and acquisition options in those business segments. (2011)
- Advisor to the New Brunswick Department of Energy on facilitating cross-border exports of energy from the Canadian Maritimes to Northeast U.S. markets. (2008-2011)
- Financial advisor to a major international corporation for investments in U.S. nuclear generating units. (2007-2009)
- Lead regulatory and market due diligence advisor to Macquarie Securities in the $7.4 billion acquisition of Puget Sound Energy. (2007)
- Retained by five Vermont electric utilities to study the comparative economics building the next generation of electric power generation within the state. Working with the utilities, the Vermont Department of Public Service, and the Electric Power Research Institute (EPRI), ten possible generation technologies were analyzed for their economic and environmental attributes. Costs were compared across technologies, and financial impacts including credit rating were examined. The report was presented in public forums and before state agencies. (2007)
- Advisor to the City of Mesa, Arizona for the potential privatization of the City's electric utility. (2007-2008)
- Independent Market Expert for a large Midwestern utility seeking a credit rating for its electric generation subsidiary. Providing a complete PJM and MISO market assessment and forward financial projections for the company's generation business including over 13,000 MW's of generating capacity. Financial projections are based on LMP price projections for the PJM-MISO interconnect, fuels prices, air emissions prices, and complete financial analysis of the business unit. Also provided support for discussions with the major credit rating agencies in conjunction with an investment bank and independent engineer. (2005-2006)
- Completed financial advisory services to a private equity consortium on the successful acquisition of a gas-fired power generating facility. The engagement included evaluation of all revenue streams, confirmation of investment economics under alternative market scenarios, and support for negotiations on key terms. (2005)
- Engaged by Goldman Sachs to assist with the financial and industry due diligence associated with the acquisition of Zilkha Renewable Energy, a wind energy company with over 20 projects under development. (2005-2006)
- Engaged by the State of Vermont to study of the feasibility of acquiring 550MW of hydroelectric generation facilities from USGen-New England. Completed a valuation of the assets, researched financing options with alternative tax-exempt and taxable structures, monitored the status of NEG's bankruptcy proceedings, researched comparable large-scale

municipalizations, studied the potential in-state and out-of-state uses for the power, and tested the market for power sales to regional utilities. Facilitated discussions with companies for equity partnership, as well as for the purposes of providing power marketing and O&M services to the project. In addition to in-house consulting staff, compiled a team of legal, engineering and financing experts to deliver a comprehensive work product reflecting all aspects of the risks and benefits of purchasing this unique set of assets out of bankruptcy. (2003-2004)

- Evaluated a major utility's unregulated energy services business units and advised management on valuation and the potential market for the businesses. Developed offering materials and represented the company in negotiations with a potential buyer. (2001-2002)
- Lead advisor in the auction of Conectiv's $875 million in fossil and nuclear electric generation assets to NRG, PSE&G, and Exelon. Provided expert testimony before the New Jersey Board of Public Utilities on the auction process and asset values. (1999-2002)
- Provided financial and market analysis to Provincial Auditor of Ontario in examination of the long-term lease arrangement for the Bruce nuclear facility between Ontario Hydro and British Energy. (2002)
- For a private equity firm, evaluated on investment in a manufacturer of electric generation equipment. Analyzed the company's sustainable technological advantage, interviewed major customers, assessed competitor positioning, and provided market and revenue projections for the investment evaluation. (1999)
- Served as technical and market advisor for an investment consortium in the evaluation of an investment in five cogeneration plants. Analyzed fuel and off-take contracts, regulatory risk, plant operating procedures, and management personnel. Provided revenue and cost projections, supported bank discussions, and assisted bid negotiations. (1998)
- Co-advisor to Sithe Energies in the auction of the company's North American assets to Reliant and Exelon, and the marketing of its assets in Australia and Asia. (1999-2000)
- Lead advisor in the electric restructuring, auction of generating assets, and long-term power contracting for Denton Municipal Electric. Conducted regular briefings for the City Council. (1999-2001)
- Co-advisor to Sierra Pacific Resources in the proposed auction of 3,000 MW of fossil generating assets. (1999-2000)
- Co-advisor to TXU in the proposed auction of 560 MW of fossil generating assets. (2000)
- Co-advisor to Boston Edison (NSTAR) in the auction of $536 million in fossil generating assets to Sithe Energy. (1997-1998)
- Co-advisor to GPU in the auction of $1.7 billion in fossil generating assets to Sithe Energy. (1997-1998)
- Lead advisor to Bangor Hydro Electric Company in the auction of $90 million in hydroelectric, transmission, and fossil generating assets to PP&L Global. (1998-1999)

**Business Strategy Experience**

- Retained by a major Canadian electric company to study the cross-border transmission constraints into U.S. power markets and identify strategic options and transmission investments for expanding capacity and energy flows into these markets. (2007)
- Retained by the Western Electric Coordinating Council's (WECC) Board of Directors to facilitate the development of the WECC's five-year strategic plan. WECC is one of eight

regional electric reliability organizations in North America, with 180 members across 14 states, and portions of Canada and Mexico. Leading the effort for Concentric, the planning process entails interviewing key stakeholders, facilitating discussion within and across member groups, gathering and presenting research, and making recommendations to the Board on the Strategic Plan. (2007)

- Engaged by a Canadian based utility company to develop its business strategy for growth in the U.S. Working with senior management, providing both a "big picture" strategic assessment of driving forces and opportunities in distribution, transmission and generation, supported by more detailed evaluation of specific investment options for presentation and discussion with its Board. (2005-2007)
- Advisor to Cook Inlet Regional, Inc., an Alaskan Native corporation, for the purpose of developing wind energy projects within the State of Alaska. (2006)
- Advisor to Tamarack Energy, Inc., for the purpose of developing renewable energy projects in the Northeast U.S. (2006)
- Engaged by a major Japanese corporation to provide assistance with the strategic evaluation of its ability to enter the $400 billion power and gas trading market. Management in Tokyo and New York required an independent assessment of the new and complex U.S. market for power and natural gas, and a determination of the company's ability to successfully compete. (2005-2006)
- Retained by an international power company to assist with evaluation of its corporate strategy and financial performance. Evaluated the company's corporate strategy using modern portfolio management tools to determine the inherent risk/reward trade-offs in the company's business portfolio. Analyzed core drivers of movements in the company's stock price and assisted the management team with engaging the Board of Directors in a strategic evaluation of the company's electric business. (2004)
- Strategic advisor to a major Public Power Authority in its evaluation of alternative business strategies and organizational structure. Provided industry benchmarking and qualitative analysis of various public power models for the Authority and developed future industry scenarios. Collaborated with team of legal and banking advisors in examining restructuring options to maximize benefits to the Authority's stakeholders. (2004-2005)
- Provided analysis for the FirstEnergy Board of Directors regarding the potential economic impact of the 2003 power outage. (2003)
- Provided a strategic assessment of an eastern utility's electric generation and marketing business. The strategic assessment included: analysis of wholesale and retail electric markets in PJM, NE and NY markets, capacity, energy and ancillary service products, transmission and congestion, customers for wholesale products, competitors, short-term and long-term financial measures of viability, and factors for success. The engagement involved brainstorming sessions with the client team, research and analysis, and concluded with a report and evaluation of the company's strategic options and business prospects. (2003)
- Developed a cost of capital and investment decision-making framework for the company's new business investments. (2002)
- Strategic advisor to a Mid-Atlantic Utility in the development and implementation of the company's generation and marketing business. (1999-2000)

## PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- Utility Strategy and Shareholder Return (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

---

## SELECTED SPEAKING ENGAGEMENTS

- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998
- "New Market Dynamics," New England-Canada Business Council Annual Meeting, November 1996
- "Fuels Markets and Generation Choices," Electric Power Research Institute Seminar, Charleston, SC, October 1989
- "Issues Underlying the Long-Term Outlook for Natural Gas Markets," International Association for Energy Economics' International Conference, Calgary, Canada, July 1987

---

## PROFESSIONAL HISTORY

**Concentric Energy Advisors, Inc. (2006 – Present)**
Senior Vice President
Vice President

**FTI Consulting (Lexecon) (2002 – 2006)**
Senior Managing Director – Energy Practice

**Arthur Andersen LLP (2000 – 2002)**
Managing Director, Andersen Corporate Finance – Energy and Utilities

**Navigant Consulting, Inc. (1996 – 2000)**
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

**TotalFinaElf (1990 – 1996)**
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

**Arthur D. Little, Inc. (1989 – 1990)**
Senior Consultant – International Energy Practice

**DRI/McGraw-Hill (1984 – 1989)**
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

**Massachusetts Energy Facilities Siting Council (1982 – 1984)**
Senior Economist – Gas and Electric Utilities

**Maine Office of Energy Resources (1981 – 1982)**
State Energy Economist

## EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

## DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 - current

# Terasen Gas Inc.
# Terasen Gas (Vancouver Island) Inc. and
# Terasen Gas (Whistler) Inc.
# (Collectively the "Terasen Utilities")

# A Review of Automatic Adjustment Mechanisms for Cost of Capital

November 29, 2010

Table of Contents


INTRODUCTION .......... 1

1. Cost of Capital Formulas .......... 3
   a. Canada .......... 3
   b. United States .......... 5
   c. ROE Practices Overseas .......... 7
2. Desirable Formula Attributes .......... 8
3. Alternative Formulaic Approaches .......... 11
   a. A Study of Formulaic Inputs .......... 11
      i. Inputs that Approximate the Movement of Equity Returns .......... 12
      ii. Inputs that Mitigate Revisions to Equity Returns .......... 15
   b. Profiles of Formulaic ROE Adjustment Mechanisms .......... 16
   c. Backcast Review of Alternative Formulae Performance .......... 23
   d. Relative Performance Across Varying Economic and Market Conditions .......... 26
   e. Transparency and Data Availability .......... 37
4. Potential Approaches for British Columbia .......... 39
5. Conclusions .......... 47

APPENDIX A – Formulaic Inputs .......... A-1

## INTRODUCTION

Concentric understands that pursuant to the British Columbia Utilities Commission's ("BCUC" or "Commission") Return on Equity ("ROE") and Capital Structure Order No. G-158-09, dated December 16, 2009, for Terasen Gas Inc. ("TGI" or "Terasen"), Terasen Gas (Vancouver Island) Inc. ("TGVI"), and Terasen Gas (Whistler) Inc. ("TGW") (collectively referred to as the "Terasen Utilities"), the Commission eliminated the formulaic ROE adjustment mechanism determining that the returns it produced were "insufficient to meet the fair return standard."[1]

The automatic adjustment mechanism ("AAM") was originally established in 1994 to adjust the 1995 rate of return on common equity for BC Gas Utility Ltd. (now TGI), Pacific Northern Gas Ltd., and West Kootenay Power Ltd. (now FortisBC Inc.). As a precursor to that Decision, the Commission had convened an evidentiary proceeding to evaluate processes or mechanisms that might be employed to improve the determination of ROE and capital structures, particularly in terms of process.[2] Ultimately, in its decision, after considering stakeholder evidence, the Commission established a process whereby the benchmark ROE for a low risk, high grade utility would be determined in a generic cost of capital proceeding and would be adjusted annually using an AAM based on long term bond yields. For purposes of determining the utility specific ROE and capital structure, the Commission would consider the utility's relative risk versus the benchmark utility and would adjust ROE and/or capital structure to account for differences in risk between the utility and the generic benchmark.

The years that followed produced a steady decline in interest rates and consistently lower ROE results. In 2008 and 2009, government bond yields, which served as the basis of the BCUC AAM, continued their decline to unprecedented low levels while corporate risk premiums and corporate capital costs spiked. Over the period since implementation of the AAM, Canadian utilities that were once receiving ROEs in parity with U.S., were receiving ROE awards 200 basis points lower than their U.S. counterparts. These factors illuminated the inherent flaws in the AAM that the Commission noted in its recent Order. Ultimately, the Commission determined that "a single variable is unlikely to capture the many causes of changes in ROE"[3] and as such, discontinued the AAM. Specifically, the Commission found:

> *A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.*

---

1 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 72.

2 In the Matter of Return on Equity, BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd. Decision G-35-94, June 10, 1994, at 2.

3 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 73.

*The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long term Canada bonds, while the cost of risk has been priced upwards.*

*In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.*

*Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.*[4]

To that end, the Terasen Utilities have retained Concentric Energy Advisors ("Concentric") to assist them with the development of a responsive filing to the Commission. Concentric has conducted extensive research and analysis regarding the Canadian ROE formula and the returns it has historically produced, in addition to analyzing the relative comparability of Canadian and U.S. utilities. Concentric had also developed a formulaic recommendation in Alberta and Ontario, which recognized the importance of litigated North American authorized returns for ROE determinations in Canada, and the integration of capital markets and similarity of regulatory models and corresponding risks for utilities in the two countries. Our discussion in this Report is underpinned by the considerable research we have conducted on these topics in connection with the following studies:

- A Comparative Analysis of Return on Equity of Natural Gas Utilities, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007;
- A Comparative Analysis of Return on Equity for Electric Utilities, prepared for the Coalition of Large Distributors ("CLD") and Hydro One Networks Inc. by Concentric Energy Advisors, June 2008;
- Concentric's Testimony before the AUC in its 2009 Generic Cost of Capital Proceeding, Application No. 1578571 / Proceeding ID. 85, on behalf of the ATCO Utilities, November 20, 2008; and most recently
- Concentric's Testimony and Presentation before the OEB in its 2009 Consultative Process on Cost of Capital, EB-2009-0084, on behalf of each Enbridge Gas Distribution, Inc. and Hydro One and the Coalition of Large Electric Distributors[5], individually, September 2009.

In order to assist the Terasen Utilities with their filing to the Commission, Concentric has examined the use of ROE formulas in other jurisdictions, contrasted these approaches with alternatives, considered the relative merits of these approaches and prepared this report summarizing our findings. Concentric is not recommending that a formula be adopted, but has reviewed and summarized the formulas in existence or that have been proposed in other jurisdictions. Additionally, Concentric has identified attributes that should be considered in the construction of an AAM in the event that one is adopted in the future.

---

4 In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, G-158-09, December 16, 2009 at 72.

5 The Coalition of Large Distributors consists of the following members: Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Powerstream Inc., Toronto Hydro-Electric Systems Limited, and Veridian Connections Inc.

The remainder of this report is organized according to the following topics: Section 1 provides an overview of formulaic approaches to cost of capital in Canada and the U.S., and a brief overview of cost of capital practices overseas. Section 2 identifies desirable formula attributes. Section 3 provides an evaluation of alternative formulaic approaches, either in practice or proposed in other jurisdictions. Section 4 describes five alternatives for consideration by the Commission, and Section 5 summarizes our conclusions.

## 1. Cost of Capital Formulas

Regulators in both Canada and the U.S. consider three primary factors when establishing a just and reasonable allowed return. These factors are: 1) capital attraction; 2) financial integrity; and 3) comparable returns. That is, the authorized return must allow the regulated utility to attract capital on reasonable terms under a variety of different market conditions, to maintain its financial integrity and borrowing capacity, and to offer investors the opportunity to earn a return comparable to other businesses with commensurate risks. Canadian regulators are guided by the benchmark ROE decision *Northwestern Utilities v. City of Edmonton* (1929)[6], U.S. regulators are guided by court decisions including *Federal Power Commission v. Hope Natural Gas* (1944)[7] and *Bluefield Water Works and Improvement Company v. PSC of W. Va.* (1923)[8], and these decisions are also cited extensively in Canada.

The use over the past two decades of formulas or AAMs applied to the utility cost of capital had, until recently, evolved to be the 'norm' in Canada, but remains an exception among U.S. regulators. The formulaic methodology provides an approach to approximating the results of periodic rate hearings, without having to expend time and resources for a full evidentiary rate hearing on cost of capital. At the center of the Canadian movement towards a formulaic methodology has been a desire for improved regulatory efficiency through a generic approach to an often contentious issue in the context of a litigated rate proceeding or settlement process. In Canada, we have seen a re-evaluation of the use of AAMs over the past two years. The following sections highlight the use of formulaic approaches and prevailing cost of capital practices in Canada, the U.S., and selectively overseas.

### a. Canada

In Canada, the adoption of a formulaic approach to setting regulated authorized equity returns was first established by the British Columbia Utilities Commission in 1994. According to a regulatory history compiled by Major and Priddle[9], through the mid-1990s Canadian utilities typically filed rate applications every one or two years, with ROEs set using one or more of four approaches: Comparable Earnings (CE), Discounted Cash Flow (DCF),

---

6 http://csc.lexum.umontreal.ca/en/1961/1961scr0-392/1961scr0-392.html

7 http://supreme.justia.com/us/320/591/case.html

8 http://supreme.justia.com/us/262/679/case.html

9 'The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results Implications", Hon. John C. Major, Former Justice, Supreme Court of Canada and Roland Priddle, Former Chair of the National Energy Board, March 2008.

Capital Asset Pricing Model (CAPM), or Equity Risk Premium (ERP). The adoption of a generic approach to ROE was ushered in by the following factors:

> *The context for the search by Canadian regulators for a generic approach to ROE was characterized by: frequent rate applications; repetitive evidence, often provided by the same expert witnesses, on the three principal tests; growing disenchantment with the CE and DCF tests; and increasing reliance on the ERP approach. That search was led by the BC Commission which "…was the first regulatory agency in Canada to examine the applicability of a generic, formula-based approach to setting natural gas or electric ROE as a means of improving the efficiency or effectiveness of the regulatory process.*"[10]

Following the precedent set by the BC Utilities Commission in 1994, several other regulatory bodies in Canada followed suit: the National Energy Board ("NEB") (1995), Manitoba (1995), Ontario (1997), Newfoundland and Labrador (1998), Quebec (1999), and Alberta (2004).[11] Concentric has identified 6 Canadian provinces in addition to the NEB that implemented a formulaic approach to adjusting ROE, although the majority of these (NEB, BC, Manitoba and Alberta) are either terminated, under review or suspension,[12] and the Newfoundland and Labrador Board invited Newfoundland Power to propose changes to the formula in its most recent decision.[13]

In the case of the BC formula, the coefficient was initially set at 1.0[14] at the time the formula was established in 1994 and was subsequently changed to 0.80[15] and then to 0.75[16]. Withstanding current developments around the formula in Ontario, Alberta, Manitoba and the NEB, the formula that has been prevalent in the majority of Canadian provinces had settled on the following equation:

---

10 Ibid., p.14.

11 Ibid, pp.15-16.

12 The NEB terminated the formula in October 2009, See NEB Reasons for Decision Multi-Client RH-R-2-94, (October 2009), part 1.2, *"Whatever the reason, given the vast experience the industry has gained in reaching negotiated settlements over the past 15 years, the Board is of the view that it is neither necessary nor appropriate to replace the RH-2-94 Decision with another multi-pipeline cost of capital decision at this time. Accordingly, the RH-2-94 Decision will not continue to be in effect."* Similarly, the BC Commission terminated the formula in December 2009, See Commission Order G-158-09, (December 2009), part 5, at 73, "*The Commission has accordingly directed that the automatic adjustment mechanism be eliminated.*" The Manitoba Commission no longer uses the formula to make ROE determinations, but rather sets return based upon targeted debt/equity ratios of 75/25. The Board still uses the formula as an upper bound reasonableness check for return determinations for Centra Gas. *See* Manitoba Board Orders 103/05 and 115/05, (October 2005), part 1.(a), at 3 *"regulatory approach alternatives – the Board confirms its intention to use both the Rate Base Rate of Return and Cost of Service methodologies, with Rate Base Rate of Return to be a test of the maximum allowable return to MH".* The Alberta Commission has suspended the formula and will consider whether to reinstate the formula in the next generic proceeding. See AUC Decision 2009-216 (November 12, 2009), part 79 & 81. *"The Commission has decided to suspend the application of the existing, or any, ROE adjustment formula. The Commission has set a generic ROE for 2009 and 2010 of 9.0 percent. The same ROE will be employed for 2011 on an interim basis….In 2011, the Commission will initiate a proceeding to consider the final ROE for 2011 and to consider whether to implement an annual ROE adjustment formula".*

13 Newfoundland and Labrador Board of Commissioners of Public Utilities, Reason for Decision: Order No. P.U. 43 (2009), p. 30.

14 BCUC Decision No. G-35-94, June 10, 1994.

15 BCUC Decision No. G-49-97, April 24, 1997.

16 BCUC Decision No. G-14-06, March 2, 2006.

$$ROE_t = ROE_{t-1} + 0.75 \times (LCBF_t - LCBF_{t-1})$$

Where $ROE_t$ is the ROE for the upcoming period and $ROE_{t-1}$ is the ROE for the previous period. The $LCBF_t$ is equal to the Long Canada Bond Forecast, made up of the average of the 10 year bond forecast 3 months out and 12 months out, plus the one month average historical spread between the 30-year and 10-year bond yield; and for any period t may be expressed as:

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

A brief overview of formulas currently in use in other Canadian provinces is provided in Figure 1 and Part 3 of this report.

### b. United States

In the U.S., formulaic approaches to determining ROE have been adopted by relatively few regulatory jurisdictions, as litigated ROE proceedings remain the prevalent means for setting ROE. Typically, a formulaic ROE approach coincides with a broader alternative regulation or performance-based rate plan that includes formulaic adjustments to rate components in addition to performance measures and incentives. Though, there are a number of U.S. jurisdictions that operate under "formula rate plans"[17] very few utilize automatic formulaic mechanisms to adjust ROE.

Of those jurisdictions that have adopted the use of formulaic adjustments to ROE, prevailing practices lie on both ends of the spectrum of complexity, with very little in between. For example, at one end of the spectrum, is the "prescriptive approach" which lays the ground rules for conducting a comprehensive ROE Study using standard methodologies and removing areas of contention by prescribing data inputs and proxy group selection criteria. This approach has been employed by Mississippi and has been considered by New York[18] and most recently Connecticut.[19]

---

17 "Formula Rate Plans", "Performance-based Rate Plans" or "Alternative Regulation Plans" are all commonly used terminology in the U.S. (and may be used interchangeably) to describe a comprehensive alternative incentive rate structure.

18 The New York commission also entertained the "uniform/prescriptive approach" in 1982 when it initiated a Generic Financing Proceeding primarily focused on maintaining the financial integrity of utilities through financial standards designed to maintain A credit ratings. This proceeding evolved to a 1991 re-examination of the adequacy of these standards in the face of increased industry competition for the telecommunications, electric, gas, and water industries. Following a two-year period involving separate working groups of utilities and other interested parties, each industry group recommended the adoption of a generic cost of equity formula. The electric/gas group formula equally weighted three methods: DCF (two-stage), CAPM (average of 4 results), and Comparable Earnings, and a twice-per-year determination to be applied to subsequent rate periods. The Commission never rendered a final decision in this proceeding. However, it has utilized the recommendations from this proceeding to guide allowed returns for utility companies in New York.

19 The state of Connecticut initiated an investigative inquiry in October 2009 "*to explore the need, desirability and feasibility of establishing a uniform methodology for determining return on equity (ROE) for public service companies during rates cases conducted pursuant to § 16-19 of the General Statutes of Connecticut (Conn. Gen. Stat.).*" Comments in that proceeding were filed earlier in the year and it appears that the DPUC is considering the "prescriptive approach" where standardized DCF and CAPM analyses are completed for a specified proxy group of companies. A final decision is anticipated in February 2011.

The second, more common approach to formulaic ROE adjustment mechanisms, is that which can be described as a simple formula, such as has been prevalent in Canada, requiring no interim ROE analyses at all. Vermont and California use simple formulas tied to bond yields, similar to the Canadian formula described above. How those formulas differ from the formula described earlier, is detailed in Part 3 of this Report.

Lastly, there are a handful of U.S. jurisdictions that fix ROE at a specified rate and do not make adjustments, but rather share overages and shortfalls with ratepayers. Alabama and Louisiana fall into this category.[20] And, there are several jurisdictions and the FERC[21] that use a formula to set parameters for the range of reasonable ROE determinations, but do not adjust ROE using a formula.[22] A brief overview of the AAMs in Canada and the U.S. is provided in Figure 1, and a more complete discussion of U.S. automatic adjustment mechanisms currently in practice and their inputs may be found in Part 3.

---

20 The Alabama Commission adopted a rate stabilization approach to the cost of equity when it set an ROE range for Alabama Power equal to 13 to 14.5%, subject to an annual rate increase cap of 5%. For rate increases above the cap, the company was at risk, and rate increases below the cap are allowed up to the 14.5% limit. Similar mechanisms were established for Alabama Gas (1983) and Mobile Gas (2002), and remain in effect today. This type of program was motivated by concerns for controlling rate increases, and evolved during a period of relatively high inflation. Similarly, in Louisiana, Entergy Gulf States has been subject to an electric formula rate plan since 2004. The current plan incorporates a 150 basis point dead-band, i.e. 75 basis points above or below a benchmark ROE of 10.65%. If EGS' earned ROE falls below the lower end of the dead-band (that is 9.9%), the company is permitted to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EGS' earned ROE exceeds the upper end of the dead-band (that is 11.4%), the company must refund 60% of the excess to customers. The other electric and gas utilities in Louisiana operate under similar rate stabilization plans. However, only Louisiana Gas Service has a cap on the amount by which O&M expenses are allowed to increase each year (i.e., $39.9 million per year adjusted for inflation and customer levels).

21 While not completely formulaic, the FERC has applied a prescriptive approach to measuring ROE for regulated transmission utilities under its jurisdiction. For natural gas pipelines, the FERC specifies proxy group selection criteria, employs a two-stage DCF methodology, prescribes sources for analyst growth rates, prescribes appropriate weightings of growth rates to be used in the analysis, and prescribes a methodology for arriving at a reasonable range of ROE results from which the midpoint is selected. This method has evolved through case precedent (as has the methodology for electric transmission ROE determinations, which differ slightly from those of gas transmission ROE determinations). For relevant FERC proceedings that established the natural gas prescriptive approach to ROE, please refer to 84 FERC ¶61,081, Williston Basis Interstate Pipeline Company, Order on Initial Decision, Issued July 29, 1998; Opinion No. 414-A, 84 FERC ¶61,084, Issued July 29, 1998; and Opinion No. 414-B, 85 FERC ¶61,323.

22 In Virginia, Title 56, Chapter 23 of the Code of Virginia prescribed a formula to be used by the Virginia State Corporation Commission ("SCC") to set a ceiling and floor for authorized ROEs. The statute states: "*In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average.*" Similarly, in Florida, the PSC uses a leverage formula to set bounds around a range of returns based on a low-end equity ratio of 40% and a high-end ratio of 100% for its water utilities. The base ROE is determined through DCF and CAPM analyses using natural gas utilities as a proxy for water utilities. See Notice of Proposed Agency Action Order Establishing Authorized Range of Returns on Common Equity for Wastewater Utilities, Docket No. 090006-WS, Order No. PSC-09-0430-PAA-WS (June 19, 2009) "*Section 367.081(4)(f), Florida Statutes (F.S.), authorizes us to establish, not less than once each year, a leverage formula to calculate a reasonable range of returns on equity (ROE) for water and wastewater (W A W) utilities...Although Subsection 367.081 (4)(f), F.S., authorizes us to establish a range of returns for setting the authorized ROE for W A W utilities, we retain the discretion to set an ROE for W A W utilities based on record evidence in any proceeding.*"

### c. ROE Practices Overseas

Looking abroad to the U.K., Netherlands and Australia, we find a reliance on price cap regulation and rates that are adjusted annually based upon inflation and productivity by the utilities. These countries (the U.K., Netherlands and Australia) each rely predominantly on a market based asset return or (WACC) methodology to set the initial base rates for a fixed period (3 to 5 years). None of these countries employ an AAM to set ROE. ROEs are set in regulatory proceedings.

All of the prevailing formulaic approaches that we have identified and their associated inputs are summarized in Figure 1.

**Figure 1: North American Formulaic ROE Adjustment Mechanisms Currently in Effect**

| Formula Inputs | Ontario (new formula) | Quebec (former BC, Ontario and NEB) formula | Newfoundland and Labrador formula | Vermont formula | California formula | Mississippi formula |
|---|---|---|---|---|---|---|
| Forecast 10-year Government Bond Yield (Average of 3 months out and 12 months out forecast) | ✓ | ✓ | ✓ | | | |
| 20 trading day average of 10-year U.S. Treasury yield | | | | ✓ | | |
| 12 month average yield Moody's Baa or A utility bond yield | | | | | ✓ | |
| Spread between 10 and 30-year Government Bond Yield (daily differences for select prior month) | ✓ | ✓ | ✓ | | | |
| Spread between Long Canada Government Bond Yield and the Blooomberg Fair Value Canada 30-Year A-rated Utility Bond index | ✓ | | | | | |
| Inversely Applies Coefficient of 20% Δ in bond yield to Equity Risk Premium (same as 80% Δ in bond yield) | | | ✓ | | | |
| Coefficient of 75% Δ in bond yield | | ✓ | | | | |
| Coefficient of 50% Δ in bond yield | ✓ | | | ✓ | ✓ | |
| Equal weighting of DCF, Risk Premium and CAPM + 12.5 bps for flotation costs | | | | | | ✓ |
| Incentives | | | | ✓ | | ✓ |
| Deadband | | | | ✓ | ✓ | ✓ |
| Formula Applied Annually | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Specified Review Period | ✓ | | | | ✓ | |

Jurisdiction

Upon examining the formulas adopted in Canada and the U.S., there are some common themes in terms of inputs and overall design elements. Generally, most formulas are tied to government or utility bond yields (only the Mississippi prescriptive ROE methodology does not utilize a bond yield directly for its adjustment mechanism). Of those formulae that rely on bond yields, a 30-year bond yield is the tenure of bonds more commonly adopted. The Canadian formulas tend to use a forecast 10-year bond yield plus the recent spread between 10 and 30-year bonds. The Vermont formula uses a historical average of the 10-year bond yield. The California formula and the newly adopted Ontario formula utilize a measure of the corporate long-term utility bond yield. In addition, in Ontario a portion of the long-term utility bond yield is forecast (the formula adds 0.50 of the change in the Long Canada Bond Forecast to 0.50 of the change in the yield spread between the A-rated Utility Bond and the Long Canada Bond from the base year.) In Canada, adjustment coefficients applied to changes in bond yields had generally been in the 0.75 range, but as is the case in Ontario above, there is movement towards a range of 0.50 as seen with U.S. formulas. In addition, several of the formulas are coupled with incentive mechanisms, deadbands, specified review periods, and all of the formulas are adjusted annually (subject to their deadbands).

## 2. Desirable Formula Attributes

Two perceived benefits of a formulaic adjustment mechanism are regulatory expediency and greater certainty for both the utility and regulator. As noted above, formulas generally update annually, without special proceedings or contentious battles between stakeholders. However, the tendency to set and forget the formula is also a primary drawback to the formulaic approach. When equity returns are generated on autopilot, there is a tendency to ignore or discount changing market conditions that may render the formulaic result unfair. There must be a balance that recognizes the need to periodically benchmark against traditional measures of required returns for regulated utilities. A functional ROE formula must be able to approximate the results that would have been produced in a rate-setting hearing process.

Establishing the starting point of the formula is the first step in the process. Great care must be exercised in establishing the initial ROE as the effects of any understatements or overstatements will be felt with each succeeding application of the formula. Concentric is of the view that the initial ROE should be set in accordance with traditional ROE setting methodologies, utilizing multiple approaches, based on a proxy group of companies with similar risk profiles, in a process where the regulatory Board hears evidence from the company and its stakeholders. Most jurisdictions go through this process each time ROE is set. A fully litigated regulatory process where stakeholder evidence is presented and heard by the commission generally provides a sound basis for a fair determination of ROE. As noted earlier, several jurisdictions have turned to the use of formulas to provide interim adjustments to ROE for estimated movements in equity markets between rate proceedings. The same regulatory objectives could be met without a formula by scheduling regular cost of capital proceedings within reasonable time frames. Periodic rate hearings encompass most of the desired attributes we consider in establishing a formulaic methodology. When utilizing an AAM, it is also important that the parameters of the formula are carefully selected. Otherwise, errors will have a compounding influence on the formulaic result as they accumulate over time.

If a formula is adopted, Concentric is of the opinion that any formulaic approach selected should give adequate consideration to the following criteria:

1. Tracks required utility equity returns
2. Ease of administration
3. Based on commercially accessible inputs
4. Promotes regulatory transparency
5. Forward-looking
6. Stability
7. Insulated from the effects of anomalous and transitory market conditions
8. Specified timetable for periodic review and/or rebasing of the formula
9. Reflects the capital market conditions faced by the utility.

Tracks Required Utility Equity Returns

The formulaic approach must accurately reflect investor-required equity returns amid varied economic and financial market conditions. A formula that relies exclusively on government bond yields, for example, may lose sight of influences in the bond market that do not affect the equities market and vice-versa. Bond yields and equity returns do not always move in tandem. For example, the sustained decline in interest rates in Canada over the last decade as a result of the monetary policy from the Federal Reserve Board and the Bank of Canada has resulted in increasingly lower formula-produced returns on equity, while litigated evidentiary proceedings in Canada and the U.S. were producing higher equity returns than those produced by the formula. Indeed, in the recent financial crisis and economic recession, credit spreads widened significantly and equity market volatility rose to unprecedented levels, ultimately causing government bond yields and corporate capital costs to move opposite to one another despite a historical positive relationship. Neither bond yield (government or corporate) provides a complete picture of required equity returns. Incorporating factors that estimate required utility equity returns or incorporating returns allowed in other jurisdictions into the formulaic adjustment mechanism might alleviate this problem. Such factors might include:

- An index of North American allowed equity returns for utilities
- DCF Calculation
- Equity Risk Premium or CAPM[23] Calculation
- Investor analyst sector or utility specific projections for ROE.

Ease of Administration

Regulators seeking to adopt formulas are generally looking for an ROE adjustment mechanism that can be updated annually without the need for a hearing process or supporting expert testimony. The process of hiring experts to provide opinions and supporting evidence on ROE issues is costly and time consuming. It is important that if an

[23] The CAPM methodology is an extension of the basic equity risk premium model. It is a theoretical model based on the investor objective of optimizing portfolio returns by minimizing systematic market risk. The CAPM model is often criticized for the subjectivity and controversy around its input parameters such as beta, the means to adjust beta, the appropriate risk free rate and the appropriate risk premium.

automatic adjustment mechanism is reintroduced, it should be readily administered by regulatory staff without the assistance of outside experts.

Based on Commercially Accessible Inputs

Formulas should utilize data that is commercially available and populated for both U.S. and Canadian companies. Often, subscription charges apply to data services (e.g., Bloomberg, DEX Universe Bond Indices), but these costs may be more than offset by the value of the data to the process.

Promotes Regulatory Transparency

Regulatory transparency refers to the openness of the process and predictability of outcomes by all stakeholders, i.e. the utility, creditors, investors, and ratepayers. A formulaic ROE that can be readily estimated by stakeholders promotes regulatory transparency, enabling investors to make forward projections based on widely understood data inputs. A formula with inputs that are not available to the stakeholders or that requires regulatory discretion in its application would not satisfy the objective of regulatory transparency as there is still uncertainty around the ultimate regulatory decision.

Forward-Looking

A formulaic ROE should provide an informed estimate of what investors will require in returns over the course of the applicable rate-setting period. For this reason, the use of yield projections and share price data are beneficial in providing a forward looking view of what is to come on the investment horizon. Both projected yield data and stock value per share data provide meaningful information as to what investors see for the future of a given credit issue or company valuation at the present time. Near-term historical data may be a reasonable proxy for projected data unless significant growth or anomalous market activity render recent history an inappropriate indicator for the projection period.

Stability

The formula should be responsive to changing market conditions but not overly sensitive to normal market volatility. It should have the stability to moderate the effects of temporary market movements so that regulators and utilities alike are not constantly making nominal changes to rates that would otherwise reverse themselves in the next period. Deadbands are used in several jurisdictions to avoid the recalculation of ROE and rates for minor changes in market conditions. If used, deadbands should strike a reasonable balance between triggering too often and not triggering often enough. A formula that is too sensitive to market volatility introduces unnecessary volatility to utility revenues and rates and results in inefficient rate revisions.

Insulated from the Effects of Anomalous and Transitory Market Conditions

Some formulaic approaches employ ceilings and floors to limit the movement of ROE from starting levels and/or trigger a review. The recent market collapse and recession of 2008 illustrated that a formula may produce inappropriate results under certain market conditions. Monitoring and setting limits based upon established thresholds such as: returns in other jurisdictions, credit spreads, changes in bond yields, changes in earnings growth, changes in stock prices, or substantial changes in ROE results may all provide valuable information to assist in the determination that the formula should be tested for appropriate results. Once such a condition is indentified, there must be an assessment and resolution process where the regulator and stakeholders arrive at an equitable solution for ensuring the fair return on equity for the upcoming period.

Specified Timetable for Periodic Review and/or Rebasing of the Formula

Any formulaic methodology should be accompanied by defined conditions that would trigger a review. A formula that remains on autopilot too long may yield inappropriate results. It is therefore necessary to routinely benchmark the formulaic result to other measures of ROE. We have observed that conditions may arise that would warrant a review, but without an established process the decision to re-evaluate the formula could be delayed by stakeholder deliberations on whether the formula is providing reasonable results. For that reason, Concentric recommends an established framework for rebasing the formula, i.e. every 3 to 5 years, unless there is substantial agreement among stakeholders that the formula is providing reasonable results. The periodic review, at a minimum, should incorporate tests beyond those upon which the formula is based. There is also value in allowing parties to petition for a review of the formula when and if they believe it is providing unreasonable results.

Reflects the Capital Market Conditions Faced by the Utility

When setting the ROE for a regulated utility, it is ideal to obtain data inputs reflecting capital market conditions faced by the utility. The integration of North American capital markets and the similarity of the legislative and regulatory processes have created a more homogenous market for utility capital. Formulas should strive to choose proxies carefully, so that risks borne by the proxy companies are representative of those to which the utility under consideration is subjected. Though no proxy is perfect, risk adjustments may be made for marked differences in risk profiles between the utility and its set of proxy companies.

## 3. Alternative Formulaic Approaches

### a. A Study of Formulaic Inputs

The components of a cost of capital or ROE adjustment formula can be broken down into two fundamental functions. First, the inputs to approximate the movement of equity returns based upon an estimated relationship between the formula input factor and the returns utility equity investors require. Through our research, we have identified the following inputs and coefficients that are present in ROE automatic adjustment mechanisms:

- Forecast Government Bond Yield
- Historical Government Bond Yield
- Corporate Bond Yield
- Utility Bond Yield
- DCF, Risk Premium and CAPM Inputs
- Formula Coefficient.

Second, some formulas incorporate protective mechanisms that mitigate the impact of the formula under certain conditions. Examples of these are trigger mechanisms that prompt a review if a predetermined threshold is met, and predetermined periods for rebasing ROE. Some formulas employ ceilings and floors that are either fixed or tied to a variable, which provide a figurative rail to keep the formula returns on track. Other mechanisms may specify a materiality threshold for adjustment and employ a deadband in which no adjustment is made. Below is a list of measures that we have identified that moderate or rebase the results of the formula in certain conditions:

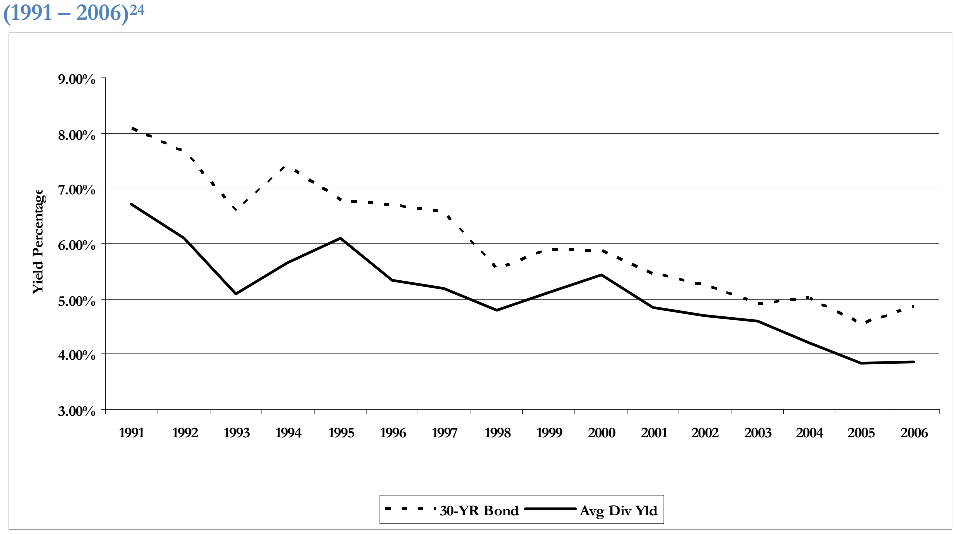
- Deadband
- Ceilings and Floors
- Trigger Mechanisms
- Review Period.

### i. Inputs that Approximate the Movement of Equity Returns

As we detailed in our Report for the OEB in 2007, there is a strong historical relationship between utility dividend yields and bond yields. In that report, we stated:

> *There is significant academic research that establishes that utility stock prices are inversely related to the level of interest rates, and likewise that dividend yields and the level of interest rates are positively correlated. [Figure 2] depicts the strong positive relationship between average annual 30-year U.S. Treasury yields and the average annual dividend yields for a representative group of U.S. gas distribution utilities.*

**[Figure 2]: Comparison of U.S. Gas Utility Dividend Yields and U.S. 30-Year Bond Yields (1991 – 2006)**[24]




> *This strong positive relationship is attributed both to the capital (and debt) intensive nature of a utility, such that a decrease in debt capital costs will result in higher earnings and higher stock prices (lowering dividend yields), and to the fact that utilities' equity returns compete with debt yields in capital markets, as utilities are generally considered among investors to be relatively stable, lower risk investments.*

24 This analysis was provided in Concentric's Report to the OEB, "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (June 2007) at 12 [Clarification Added]. Dividend yields were represented for the average of all 15 natural gas distribution utilities covered by the Value Line Investment Survey's March 16, 2007 publication. 30-Year Treasury bond yields were obtained from Yahoo! Finance.

Similarly, bond yields are positively correlated to utility authorized equity returns as regulatory commissions recognize that the return they provide to equity holders should provide a premium over corporate borrowing costs. That premium varies with the level of interest rates and generally moves inversely to interest rates. Below, we have included an analysis of U.S. and Canadian bond yields, which demonstrates the relationship between authorized utility equity returns and both corporate and government bond yields using both Canadian and U.S. bond yield data. We have used U.S. authorized equity return data as a proxy for Canadian utility equity return data, since the prevailing authorized utility equity returns in Canada for the period under study were formulaically determined using bond yields as a direct input, creating a problem with circularity. Because the level of interest rates has trended similarly between Canada and the U.S., we believe it is reasonable to expect that equity returns would also trend similarly. As reflected by the large red circle, the sensitivity to government bond yields ranges from 0.2888 to 0.4657; and to corporate bond yields ranges from 0.4302 to 0.5205.

**Table 1: Statistical Analysis Describing Sensitivity of Authorized Returns to Long Term Bond Yields**

| | Intercept | $t\text{-stat}_{\alpha}$ | B | $t\text{-stat}_{x}$ | $R^2$ |
|---|---|---|---|---|---|
| **RRA Quarterly Avg. Authorized Returns vs. 30-Year Government Bond Yield** | | | | | |
| Quarterly weighted-average (weighted by the number of electric and gas cases) Q4 1989 - Q3 2010 (84 observations) versus the 30-Year U.S. Treasury Bond | 8.4057 | 41.3305 | 0.4657 | 13.9068 | 0.7022 |
| Quarterly weighted-average (weighted by the number of electric and gas cases) Q4 1989 - Q3 2010 (84 observations) versus the 30-Year Government of Canada Long Bond | 9.3038 | 59.2100 | 0.2888 | 11.7477 | 0.6419 |
| **RRA Quarterly Avg. Authorized Returns vs. 30-Year A-Rated Utility Bond Yield** | | | | | |
| Quarterly weighted-average (weighted by the number of electric and gas cases) versus Moody's A-rated Utility Bond Index Quarterly average (daily average for each month in the quarter then three months averaged) Q4 1989 - Q3 2010 (84 observations) | 7.3311 | 27.3554 | 0.5205 | 14.4970 | 0.7193 |
| Quarterly weighted-average (weighted by the number of electric and gas cases) versus Bloomberg Canada A-rated Utility Bond Index[25] Quarterly average (daily average for each month in the quarter then three months averaged) Q2 2002 - Q3 2010 (34 observations) | 8.0691 | 16.4233 | 0.4302 | 5.0879 | 0.4472 |

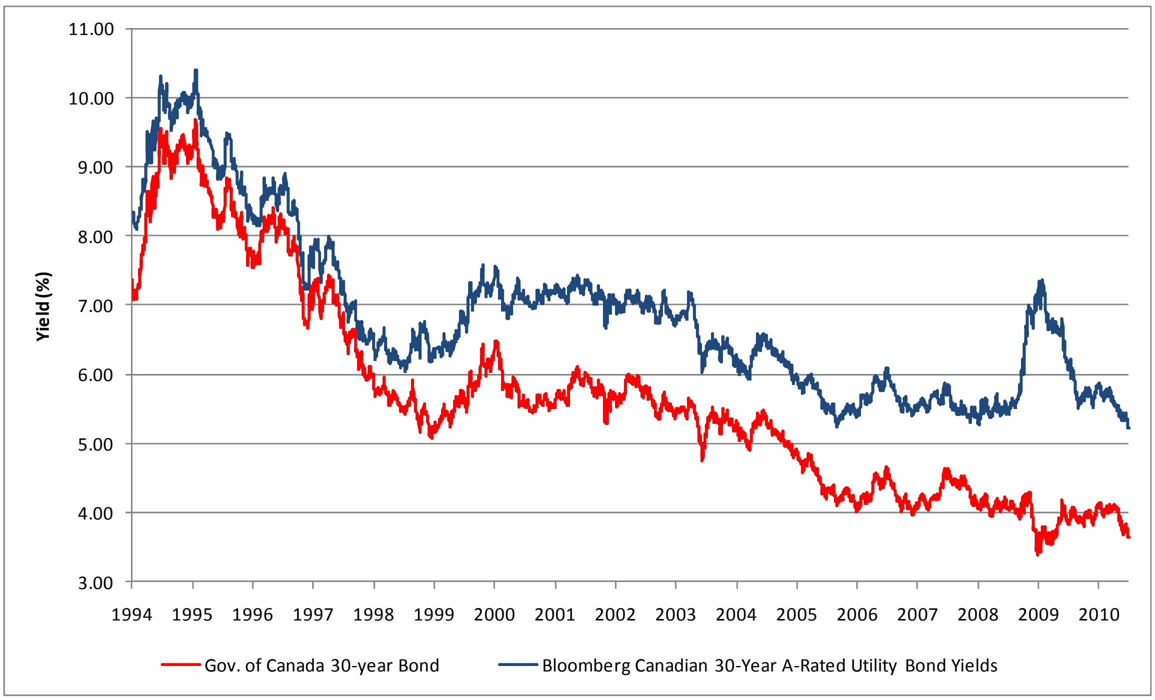
This level of sensitivity may be compared to the 0.75 coefficient which has prevailed in the Canadian ROE formula, where for every one percentage point change in government bond yields the return on equity moves by 0.75. In the analyses summarized in Table 1, the

25 The Bloomberg A-rated Utility Bond Yield Index was first reported on March 5, 2002.

regression results indicate that this sensitivity anticipated by the Canadian ROE formula has been overstated and is more appropriately in the range of 0.50.[26]

Generally, government bond yields and corporate bond yields enjoy a strong positive relationship. However, as Figure 3 shows, they do differ. Government bond yields are heavily influenced by changes in fiscal and monetary policy, whereas the influences of fiscal and monetary policy on interest rates may be very different than corporate risk. As a case in point, Figure 3 illuminates the divergence between corporate bonds and government bonds that occurred from September 2008 through early 2009, during the global economic crisis. The credit spreads increased dramatically as the corporate bond moved higher and the government bond moved lower. Today, those spreads have returned largely to their previous levels.

**Figure 3: Corporate Utility A-Rated 30-Year Bond Yields versus Canadian Government 30-Year Bond Yields**




As the Figure shows, corporate bond yields and government bond yields may become delinked. Corporate utility bond yields provide a better indication of the utility's true capital costs as the increase in corporate risk implied by the increase in credit spread will likely be at least paralleled on the equity side. It is a rare occurrence when debt carries a higher risk (credit spread) than equity (equity risk premium). This matter was recently considered by the California Commission, where its decision considered the relative merits of using a government bond yield versus a corporate bond yield as the platform for the ROE formula:

[26] This conclusion is consistent with conclusions reached in the Concentric Energy Advisors comments filed on behalf of EGDI, OEB 2009 Consultative Process on Cost of Capital Review EB-2009-0084, September 8, 2009, at 5.

*The purpose of an interest rate benchmark is to gauge changes in interest rates that also indicate changes in the equity costs of utilities. U.S. Treasuries are more sensitive to economic changes and risks in the international capital markets than utility bonds because they are bought and sold globally. However, U.S. utility bonds are generally affected less than Treasuries as a result of major shifts of international capital because a majority of U.S. utility bonds are traded within the U.S.*

*Consistent with our use of utility bond interest rates in ROE, PBR, and MICAM proceedings and desire to use an index that more likely correlates and moves with utility industry risk, utility bonds should be adopted for the CCM (Cost of Capital Mechanism) index. In this regard, the Moody's Aa utility bond rates should be used for those utilities having an A credit rating and Moody's Baa utility bond interest rates for utilities having a B credit rating.*[27]

Though a formula tied to government or corporate bond yields may, with proper specification of inputs and a pre-determined process for review and calibration, provide a reasonable basis for an automatic adjustment mechanism for ROE, other jurisdictions have incorporated direct estimates of equity returns into their AAMs. For example, Mississippi utilizes a weighting of a series of ROE analyses, i.e. DCF, risk premium and CAPM, developed in accordance with prescribed parameters, to develop their adjustment mechanism. This methodology most closely emulates the evidence typically provided in a litigated rate process, but it is complex and would require greater staff resources for administration.

Other means of factoring equity returns into AAMs might include incorporating the ROEs authorized by other jurisdictions into the formulaic mechanism. Concentric proposed such a formula in Alberta and Ontario, where an equal weighting of the formulaic adjustment mechanism (specified with a coefficient of 0.50 and use of the Bloomberg 30-year A-rated utility bond yield) was combined with an index of North American allowed utility returns applied to the initial ROE.

### ii. Inputs that Mitigate Revisions to Equity Returns

One cannot be sure that any of the formulaic approaches would satisfy the fairness standard over time. To provide a safeguard against the formula resulting in deficient or excess returns in a period of unanticipated capital market circumstances, there are a number of safeguards that may be employed to ensure that equity returns do not get too far off track.

<u>Deadband</u>
The deadband is a specified range in which no changes will occur. Deadbands used within a certain range promote regulatory efficiency by not changing the return portion of the utility's calculated revenue requirement for relatively small changes in the formulaic ROE. Recognizing that the ultimate objective is a fair return, a dead band is viable as long as the base ROE is fair, the expected deviation from the allowed return is neutral and fluctuations

[27] *Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008 and Related Matters*, Decision of ALJ Michael J. Galvin, mailed April 29, 2008, at 13.

do not jeopardize the financial integrity of the utility or overcompensate shareholders at the expense of ratepayers. The deadband is appropriate when regulatory efficiency can be optimized without sacrificing a fair return.

Ceilings and Floors

Ceilings and floors provide parameters around a formula, inhibiting any results that are either higher than the ceiling or lower than the floor. If the formula yields results outside of those parameters, the default result is either the ceiling or the floor. Ceilings or floors may not be symmetrical, and may be tied to inputs, ROE determinations, or ultimate revenue requirement increases (rate caps) produced by the formula.

Trigger Mechanism

Trigger mechanisms are generally used so that if the formula yields results outside of established limits, some action is taken. Often times, moving beyond the limit will trigger a review or rebasing of the formula. Trigger mechanisms may be tied to a benchmark (such as specified deviation from average North American litigated allowed returns), may be tied to changes in the formulaic inputs (such as specified changes in bond yield inputs), or may be tied to the actual result of the formula (symmetrical ceiling and floor established from the starting ROE).

Specified Review Period

A formal review proceeding may be implemented at specified time periods, where ROE may be reviewed, recalibrated and reset, if parties deem necessary. It provides certainty that the formula's ability to adequately track returns will be periodically addressed.

A more complete discussion of these formulaic inputs may be found at Appendix A.

### b. Profiles of Formulaic ROE Adjustment Mechanisms

Concentric has identified formulas in use in Canadian and U.S. jurisdictions. A brief overview of each formula follows.

Ontario ROE Formula

The Ontario Energy Board recently decided in its 2009 Consultative Process that the specification of the relationship between interest rates and the equity risk premium in the then prevailing Ontario formula (described previously) would be improved by the addition of a term that incorporates corporate bond yields. The Board determined that it would use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-year A-rated utility Bond Index yield and the long Canada bond yield. The Board also determined that the sensitivity of the formula to bond yields should be reduced from 0.75 to a 0.50 adjustment factor for each 1 percent change in the long-term bond yield forecast. In addition, the Board provided that parties may ask the Board to review cost of capital policies when they feel it is appropriate or the Board may do so on its own initiative. The Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated ROE continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency. The current Ontario formula is given by the following equation:

$$ROE_t = ROE_{t-1} + \left[0.50 \times (LCBF_t - LCBF_{t-1}) + 0.50 \times \sum_i \frac{30\_CUtA\_B_{i,1} - 30\_CB_{i,1}}{i_t}\right]$$

In this formula, the long Canada Bond Forecast is combined in equal weighting with the Average daily Spread for the most recent three months, between A-rated Canadian Utility Bonds and 30-year Government of Canada Bonds. The Long Canada Bond forecast is given by the following equation:

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

Quebec

Similar to the former NEB, Ontario and BC Automatic Adjustment Mechanisms, Quebec's Automatic Adjustment Formula was adopted in 1999 by Decision D-99-11, case R-3397-98. The Formula was subsequently reviewed and renewed in 2004 by Decision D-2004-196, case R-3529-2004, and again in 2009 by Decision D-2009-156, case R-3690-2009 for the 2011 test year. The adjustment coefficient in the Automatic Adjustment Formula reflects 75% of the variation in the forecast rate of return on 30-year Canada bonds.[28] The Quebec formula is pictured in Section 1 of this Report.

Newfoundland and Labrador

The automatic adjustment formula was implemented as a result of Board Order P.U. 16 (1998-99). Calculation of the return on common equity is based on the equity risk premium model with 30-year Government of Canada bonds representing the risk-free rate. The forecast long-term government bond rate for the current year is subtracted from the following year's forecast value; the difference is then multiplied by a factor of 0.20 and the result is used to adjust the risk premium in the opposite direction. The adjusted risk premium is added to the forecast long-term bond rate to produce the rate of return on common equity for the following year. (This is mathematically equivalent to applying 80% of the change in long-term government bond yields to the previous year's ROE).

The formula is given by the following series of equations:

$$ROE_t = RP_t + LCBF_t$$

Where the current risk premium is given by:

$$RP_t = RP_{t-1} - 0.20 \times (LCBF_t - LCBF_{t-1})$$

---

[28] Regie de l'energie, Decision D-2009-156, December 7, 2009.

And the Long Canada Bond Forecast is given by the average forecast for the 10-year bond plus the average daily spread for the most recent month between the 30-year Government of Canada Bond and the 10-year Government of Canada Bond.

$$LCBF_t = \left[\frac{10\_CBF_{3,t} + 10\_CBF_{12,t}}{2}\right] + \sum_i \frac{30\_CB_{i,1} - 10\_CB_{i,1}}{i_t}$$

<u>Vermont ROE Formula</u>

The Vermont Public Service Board ("VPSB") has (under state law) permitted its utilities to adopt alternative regulation plans ("ARPs"), which have been developed and proposed by the utilities and their terms and have been negotiated and settled in Memorandums of Understanding ("MOUs") with the VPSB. Green Mountain Power has been operating under an Alternative Regulation Plan, which includes an AAM, since 2006. The Board approved a formulaic ROE and an adjustment factor that provides incentives for managing controllable costs as part of Green Mountain Power's ARP. The Formula adjusts ROE by 50% of the difference between the average ten-year Treasury note yield to maturity as of the last 20 trading days ending two weeks before the annual filing, and as of the 20 trading day period used for the last adjustment to the return on equity component. The ROE Performance Adjustment is intended to offer an opportunity to earn a higher ROE by exceeding the standard of excellence the Company had reached to date, when benchmarked against comparable utilities.[29] The incentive adjustment is limited to 50 basis points (upward or downward), and is allotted based on the quintile in which the company's peer group ranking falls.

The Green Mountain Power formula combines an earnings sharing mechanism with its formulaic ROE methodology that reflects the difference between the achieved versus authorized ROE for the preceding calendar year. The earnings sharing adjustor employs a 75 basis point deadband and a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return. There is no sharing of earnings above the targeted return.

The formula may be expressed as follows:

$$ROE_t = ROE_{t-1} + 0.50 \times \left[\sum_i \frac{10\_USB_{i,20}}{i_t} - \sum_i \frac{10\_USB_{i,20}}{i_{t-1}}\right]$$

Since the adoption of the formula by Green Mountain Power, Central Vermont Public Service has adopted the same formulaic methodology to adjusting ROE with the commencement of its Alternative Regulation Plan in 2008. Vermont Gas's formula remains fixed under their current Alternative Regulation Plan, which will be up for renewal in September 2011.

29 State of Vermont, Public Service Board, *Petition of Green Mountain Power Corporation for Approval of an Alternative Regulation Plan (Plan II)*, Docket No. 7585, Order entered April 16, 2010, at 4.

California ROE Formula

A formulaic approach to adjusting ROE was implemented in 2008. The 2008 test year cost of capital applications were divided into two phases. The first phase established the applicable ROE for each of the utilities. The second phase led to the adoption of a cost of capital mechanism for the three major energy utilities. This mechanism is applied to each individual utility's established ROE from Phase I, and required the utilities to file cost of capital applications every third year, beginning with the 2011 test year. The principal features of the approach are:

- Establishes an interest rate benchmark (Moody's utility bond yield on date formula commences);
- The adjustment is based on 0.50 of the annual change in Moody's utility bond yields;
- There is a 200 basis point deadband, meaning that if interest rates change by less than 100 basis points from the benchmark interest rate, either up or down, the ROE remains unchanged;
- The interest rate benchmark is updated each time the formula exceeds the deadband and results in an adjustment to ROE; and
- A full ROE hearing is conducted every three years.

The California Commission looked favorably on the proposition that that the cost of capital formula would enable utilities, stakeholders, and the Commission to reduce and reallocate their respective workloads for litigating annual cost of capital proceedings. The formula may be expressed as follows:

$$if\ (Moodys\_Ut\_Bnd_t - Moodys\_UT\_Bnd_{benchmark}) > 100\ basis\ points, then$$

$$ROE_t = ROE_{t-1} + 0.50 \times (Moodys\_Ut\_Bnd_t - Moodys\_UT\_Bnd_{benchmark})$$

and

$$Moodys\_Ut\_Bnd_{new\ benchmark} = Moodys\_UT\_Bnd_t$$

Or

$$if\ (Moodys\_Ut\_Bnd_t - Moodys\_UT\_Bnd_{benchmark}) < 100\ basis\ points, then$$

$$ROE_t = ROE_{t-1}$$

The Commission selected a corporate utility bond index over U.S. Treasuries, reasoning that the latter is more sensitive to economic changes and risk in international capital markets than utility bonds because they are bought and sold globally, and found that U.S. utility bonds are generally less affected by major shifts in international capital. The Commission also found that a utility bond index would more closely correlate to a utility's risk than would a Treasury bond.

The Commission order cautions that "a deadband that is overly sensitive to interest rates causes needless volatility in revenues and rates. Conversely, a deadband that never triggers can impose unnecessary costs on shareholders or ratepayers, depending on which direction interest rates move." A deadband needs to strike a reasonable balance between triggering too often and not triggering often enough. The Commission found that a 100 basis point deadband over a 12-month average measurement period appropriately mitigated the volatility of interest rates.

The Commission decided in the absence of long term experience with this formula, that a shorter-term review period be established. As a result, and consistent with majority consensus, the Commission required a full cost of capital review on a triennial basis.

<u>Mississippi ROE Formula</u>

Mississippi's utilities operate under formula rate plans tailored to each utility. These rate plans incorporate a prescriptive approach to setting ROE based on specified weightings of common ROE methodologies: DCF, Risk Premium and CAPM. The prescriptive approach defines any areas of contention, such as proxy group selection criteria and data inputs, and though complicated and comprehensive, results in an ROE analysis without litigation or contention. The Commission in effect has reached agreement with the utilities and stakeholders as to methodological approach and sources of inputs necessary to arrive at a reasonable estimate of ROE. The inputs are agreed upon and specified, such as growth rates, betas, etc., as are any adjustments to ROE for flotation costs and performance incentives, and are used annually to adjust ROE.

In simple terms, a benchmark ROE is calculated each year based upon the prescribed methodologies and inputs. The benchmark ROE is further adjusted by a performance factor, to arrive at the annual performance-adjusted benchmark. If the resulting performance-adjusted benchmark ROE yields an authorized return that differs from the calculation of the expected return (detailed below) by greater than a specified deadband, revenues are either increased or decreased to make up for the shortfall or overage in expected returns. The authorized revenue increase for annual rate increases is subject to a 4% revenue cap. For some utilities, the revenue cap acts as a hard cap (or ceiling) and for others it may signal the need for an ROE proceeding (a trigger mechanism).

Below is a summarization of the approach used to develop Atmos Energy's performance adjusted ROE benchmark in accordance with its rate stabilization rider. Atmos Energy is a Mississippi gas utility and the methodologies prescribed in its rate stabilization rider are generally characteristic of those applied to other Mississippi utilities.

The first step is calculating the Expected Equity Return given by the following formula:

$$\left(\frac{Test\ Year\ Revenues - Test\ Year\ Expenses - Adjs. for\ Known\ \&\ Measureable\ Differences}{Average\ Rate\ Base\ Equity}\right)$$

The performance adjusted ROE benchmark is given by the following formula:

$$PA\_ROE_{bench} = \frac{DCF + Regression\ Analysis + CAPM}{3} \mp PA$$

The methodologies are prescribed as follows:

Proxy group screening criteria for parent companies of operating utilities:

- Gas Distribution Utilities listed by the Value Line Investment Survey
- Must have annual operating revenues not less than one-half nor more than twice those of Atmos Energy Corporation. If this results in less than 10 sample companies, such group shall be represented by the ten companies in the Value Line Survey list having the closest annual revenues to Atmos Energy Corporation.
- Must have each of the following earnings growth rates: Value Line, Zacks, I/B/E/S.
- Must have Value Line beta
- Must pay dividends and have a positive dividend growth rate
- Atmos Energy must be excluded from the Group

DCF Approach

$$k = \frac{D_1}{P_0} + g$$

- Expected dividend yield is calculated by increasing the current dividend by the applicable growth rate (g) at the normal dividend change timing pattern as stated in Value Line.
- Stock prices are the average daily closing stock prices from Yahoo Finance for the one month prior to the determination of the ROE.
- Earnings growth rates are the average of the projected earnings growth rate for each of the comparable companies in Value Line, I/B/E/S Thomson Financial, and Zack's.
- The DCF model is performed for each comparable company, and the truncated mean is used, which is derived by discarding the highest and lowest DCF results.

The Regression Analysis Approach

$$Y = a + b\ (x)$$

- "Y" represents the average return on common equity capital allowed in all gas rate cases by state regulatory commissions as reported by RRA for a given calendar year.
- The independent variable "X" represents Moody's average annual A-rated public utility bond seasoned for the year corresponding to the allowed return on equity.
- The model uses 15 years of historical monthly data.
- $Y_{current}$ is solved by applying the resulting regression coefficients "a" and "b" to the average monthly Moody's A-rated utility bond yields "x" for the most recent calendar quarter.

CAPM Approach

$$CAPM = R_f + \beta\ (RP)$$

- Risk-free rate is the simple average of the last three monthly averages of yield on 20-year Treasury bonds as reported by Federal Reserve Statistical Release H.15(519).
- Beta is the average of the betas (adjusted) as stated in Value Line for the same group of comparable utilities in the DCF analysis.
- The Risk Premium is the difference between the arithmetic average annual return on Common Stock (Total Return Index) and in Long-term Government Bonds (Total Return Index) found in the Ibbotson Associated Yearbook from 1926 through most recent data.

Performance adjustments ranging from positive to negative 50 basis points are added to the benchmark ROE to arrive at the performance adjustment benchmark ROE. The performance adjustments vary among utilities in Mississippi, but in the case of Atmos Mississippi, the performance adjustment is based on the weighting of a price benchmark study (weighted 75%) and a customer satisfaction survey (weighted 25%).

To determine the actual revenue increase or decrease, an example of the calculation, which assumes a rate base of $50 million and an equity ratio of 40%, or an equity rate base of $20 million and annual revenues of $10 million is as follows:

| | |
|---|---:|
| Expected Equity Return | 8.00 |
| Less: Performance-Adjusted Benchmark ROE | 11.50 |
| Difference | (3.50) |
| Absolute Value of Difference > 100 basis point deadband? | YES |
| Allowed Adjustment to Rates | 3.50 |
| Multiplied by: Equity Rate Base | 20,000,000 |
| Δ in Equity Revenue to Achieve Rate Base Required Return | 700,000 |
| Divide by: (1-Tax) for tax expansion | .65 |
| Total Revenue Change Required | 1,076,923 |
| Actual Gross Revenue for Test Period | 10,000,000 |
| Apply 4% Cap to Actual Gross Revenues | 400,000 |
| Rate Adjustment = MIN(Revenue Change Required or 4% Revenue Cap) | 400,000 |

The Mississippi Commission has attributed the following benefits to the adoption of its formula rate plan:

- A systematic process that essentially stabilizes earnings, while allowing the utility a reasonable opportunity, with efficient operation, to achieve its allowed return with neither on-going excess earnings nor ongoing under-earnings;
- Rates can be adjusted based on performance and/or service quality;
- More systematic and frequent reviews of utility books and records which results in a utility's earnings and services being more closely monitored by its regulators;
- Stability of rates;
- A significant savings in time, resources, and costs that are generally related to traditional rate case filings; and
- Higher credit rating.

### c. Backcast Review of Alternative Formulae Performance

In an effort to evaluate the performance of the alternative methodologies relative to one another and to non-formulaic allowed returns, Concentric benchmarked the formulas in a backcast analysis that commences in 1994, the beginning of the BC formulaic adjustment approach. Each formula (with the closest proxy for inputs) is modeled to mimic its hypothetical performance over the past 16-year period. In this analysis, we begin with a starting point of 10.75% in 1994, the actual starting point for Terasen's (then BC Gas) ROE awards under the formula. To promote comparability across formulas and to eliminate variability due to timing alone, we have adjusted each formula annually based on a March 31st closing value for all inputs (except as noted) regardless of the adjustment time frames prescribed by each of the respective Commissions. In cases where the formulas relied upon forecast inputs, such as forecasted bond yields, we have backcast the actual bond yields for the given bond in our analysis. Because the backcast analysis establishes each formula beginning in 1994 at 10.75%, and updates each formula in the first quarter of the year, which differs from the actual timing in which the formulae are set and updated, and because we have used actual historical inputs as a proxy for forecast formula inputs, there are differences between the formula results we have generated in our backcast analysis and the actual ROE results for each respective formula's historical ROE application. This method allows for a comparison of each formula on an apples-to-apples basis.

The alternatives considered in our backcast analysis are those unique formulas identified through our research both in Canada and the U.S.: (i) the newly adopted Ontario formula; (ii) the Quebec (former BC, Ontario and NEB) formula; (iii) the Newfoundland and Labrador formula; (iv) the Vermont formula; (v) the California formula (with a 100 basis point deadband); (vi) the California formula (excluding the deadband); and (vii) the Mississippi formula (as it has been applied to its natural gas utility ATMOS). In addition, we have modeled a formula that is tied entirely to an index of U.S. utility authorized return data generated by Regulatory Research Associates ("RRA")[30] to facilitate comparison to the average U.S. litigated authorized returns over the same period. Concentric had also developed a formula which weights U.S. authorized returns equally with a corporate bond yield adjustment mechanism (using a 50% adjustment factor). Concentric recommended this formula in Alberta and Ontario to recognize the importance of litigated North American authorized returns for ROE determinations in Canada, and the integration of capital markets and similarity of regulatory models and corresponding risks for utilities in the two countries. Lastly, we have included Terasen Gas Inc.'s actual allowed returns for comparison purposes. The details of how each formula is modeled in our backcast analysis are described more fully in Table 2.

[30] A comprehensive data base of regulated utility sector data (including summary data and ranking of all U.S. utility commissions) and utility-specific regulatory data. RRA is owned by SNL Financial which collects, standardizes and disseminates all relevant corporate, financial, market, and M&A data, as well as news and analysis for the Banking, Financial Services, Insurance, Real Estate, Energy and Media & Communications industries.

**Table 2: Description of Formulas in Backcast Analysis**

| Backcast Modeling Description | Technical Attributes |
|---|---|
| ***Ontario Formula-based Return on Equity (gray line)***<br><br>**$ROE_n = ROE_{n-1} + 0.50 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1}) + 0.50 \times [(\text{Can Util Bond}_n - \text{Gov Can 30-year}_n) - (\text{Can Util Bond}_{n-1} - \text{Gov Can 30-year}_{n-1})]$** | o Gov Can 30-year equals Government of Canada 30-year bond yield<br>o Can Util Bond equals Bloomberg Fair Value 30-year Canada A-rated Utility bond index |
| ***Québec (former BC/Ontario/NEB) Formula-based Return on Equity as it has been most recently applied (orange line)***<br><br>**$ROE_n = ROE_{n-1} + 0.75 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1})$** | o Gov Can 30-year equals Government of Canada 30-year bond yield<br>o The formula, as prescribed by the Régie (and formerly BC, Ontario, and the NEB), depends on forecasts of long-term Government of Canada bond yields. In order to express the formula on an apples-to-apples basis with others, actual bond yields were used. |
| ***Newfoundland and Labrador Automatic Adjustment Mechanism (blue dotted line)***<br><br>**$ROE_n = \text{Gov Can 30-year}_n + ((ROE_{n-1} - \text{Gov Can 30-year}_{n-1}) - 0.20 \times (\text{Gov Can 30-year}_n - \text{Gov Can 30-year}_{n-1}))$** | o Gov Can 30-year equals Government of Canada 30-year bond yield<br>o The formula, as amended by the PUB, depends on forecasts of long-term Government of Canada bond yields. In order to express the Newfoundland and Labrador formula on an apples-to-apples basis with others, actual bond yields were used. |
| ***Vermont ROE Adjustment Mechanism (purple line)***<br><br>**$ROE_n = ROE_{n-1} + 0.50 \times (\text{US 10-year Treas}_n - \text{US 10-year Treas}_{n-1})$** | o US 10-year Treas. equal to U.S. Government 10-year Treasury bond yield |
| ***California Cost of Capital Mechanism (red line)***<br><br>**$ROE_n = ROE_{n-1} + 0.50 \times (\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$ where $(\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$ must be greater than 100 basis points (1.00%)** | o Moody's Baa equals Moody's Baa-rated Utility Bond Index<br>o Moody's Baa benchmark initially equal to March 31, 1994 closing value, reset to any value of the Moody's index that triggers the cost of capital mechanism (year-over-year change greater than 100 basis points) |
| ***California Cost of Capital Mechanism without dead band (red dotted line)***<br><br>**$ROE_n = ROE_{n-1} + 0.50 \times (\text{Moody's Baa}_n - \text{Moody's Baa benchmark})$** | o Moody's Baa equals Moody's Baa-rated Utility Bond Index<br>o Moody's Baa benchmark initially equal to March 31, 1994 closing value. |
| ***Atmos Energy Corp. – Mississippi (green line)***<br><br>**Actual results of "calculation of benchmark return on rate base equity" for 2002 through 2009, calculated each year by Atmos based on a prescriptive formula** | o Formula is the average of a Discounted Cash Flow Analysis, Capital Asset Pricing Model, and Risk Premium Regression Analysis<br>o A backcast of this formula is not feasible due to data constraints but historical results of the formula are presented. |
| ***U.S. Weighted-Average Authorized ROE Index (thick black line)***<br><br>**$ROE_n = ROE_{n-1} \times \text{US\_ROE\_Index}_n$** | o *US ROE Index* equal to weighted-average authorized ROE for U.S. electric and natural gas utilities provided by Regulatory Research Associates<br>▪ Average for each quarter weighted by number of cases<br>▪ Index equal to $\text{Year}_n\text{Q1} / \text{Year}_{n-1}\text{Q1}$ |
| ***Concentric Alberta/Ontario Recommendation (blue line)***<br><br>**$ROE_n = \text{Average}(ROE_{n-1} + 0.50 \times (\text{Can Util Bond}_n - \text{Can Util Bond}_{n-1}),\ ROE_{n-1} \times \text{US ROE Index}_n)$** | o Can Util. Bond equals Bloomberg Fair Value 30-year Canada A-rated Utility bond index<br>▪ Index did not start until 3/5/2002, quarterly data prior to that provided by Canadian Bond Rating Service |
| ***Terasen Gas Inc. Actual Authorized ROE (black dotted line)*** | o BCUC allowed ROE for BC Gas Utility Ltd. and Terasen Gas Inc. as reported in annual reports |

If we were to use the BCUC litigated ROE proceedings beginning with a 10.75% ROE, authorized by the Commission in 1994, and a 9.5% ROE, authorized by the Commission in 2009 as data points to indicate the desired formulaic path over the period, in Figure 4, we observe that formulae with a lower sensitivity to changes in bond yields, i.e. the California, Ontario and Vermont formulae or the Concentric recommended weighted formula (50% regression formula and 50% index of average North American litigated returns) have generated the formulaic path that best connects the BCUC's decisions at each end of that 16-year period.

It is interesting to note that the coefficient that would have been necessary under the former BC ROE adjustment formula to link the ROE set by the Commission in 1994 of 10.75%[31] to the ROE set in 2009 of 9.5%[32], as a function of 30-year government bond yields, all else being equal, would have been 0.34 (or each one percent change in the 30-year government bond yield would effect a 0.34 percent change in the allowed return), much lower than the BC formula coefficient at any time during the history of the formula, and closer to the historical relationship between government bond yields and U.S. regulated authorized returns represented in Table 1, of 0.29 to 0.43.

Conversely, formulae that are highly sensitive to changes in bond yields (Newfoundland and Labrador with a coefficient that effectively has 0.80 sensitivity to changes in government bond yields) and the Quebec (former BC/Ontario/NEB) formula (with a 0.75 sensitivity to changes in government bond yields) have generated progressively lower ROEs over the 16-year period than actual litigated returns in either BC or the U.S. Our research has shown that this is due to the formulas' sensitivity to the sustained decline in interest rates, which has characterized government bond yields over the period. These effects are illuminated by comparing the results of those formulae to the Vermont formula, also based on government bond yields, but with reduced sensitivity of 0.50 (applied to the 10-year U.S. Treasury bond yield). As we may observe in Figure 4, the lesser sensitivity to changes in government bond yields in the Vermont formula results in formulaic outcomes that are much more in line with litigated ROEs over the period and accordingly results in a more moderate response to volatility in government bond yields. We observe that the California formula, with a sensitivity of 0.50 to changes in corporate utility bond yields, also yields a moderate ROE result on par with ROEs determined in litigated rate hearings and only slightly higher than the results of the Vermont formula (based on government bond yields).

Because of the abundance of regulated utilities in the U.S. and the number of litigated returns that arise out of the regulatory process in 50 state regulatory jurisdictions, the U.S. provides an excellent source for North American utility equity return data. Though we would not expect the average U.S. utility return to necessarily be identical to a return issued for a given Canadian utility (although it is possible to select a proxy group of U.S. companies that would be comparable to a Canadian utility), directionally we would expect average returns in the two countries to move in tandem. To that end, we have developed an index, which divides the current year weighted average U.S. ROE decisions by the base year average and applies that index on a year over year basis to the litigated BCUC decision in

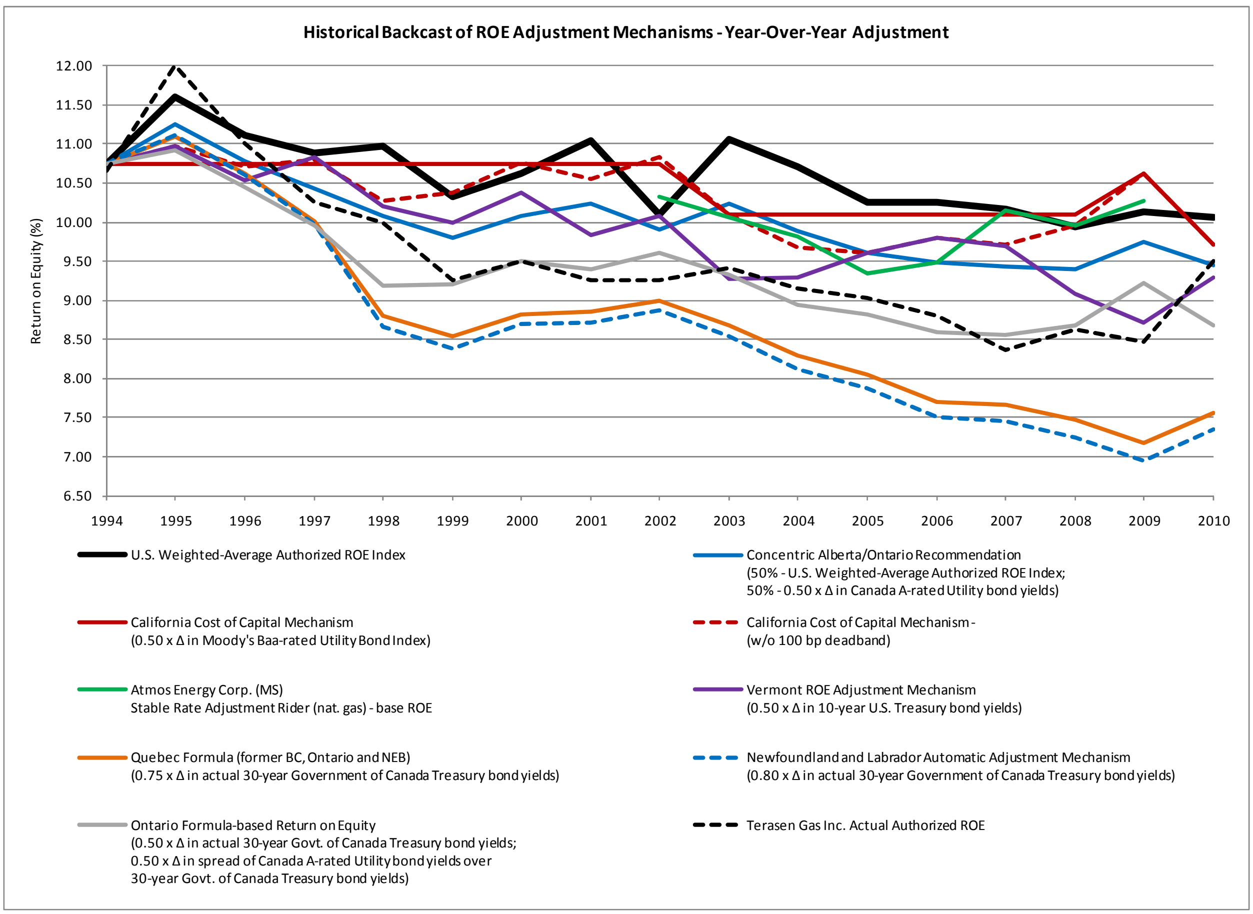
31 BCUC Decision No. G-35-94, June 10, 1994.

32 BCUC Decision No. G-158-09, December 16, 2009.

1994 of 10.75%, to develop a directional benchmark for BCUC ROE that would parallel the changes in U.S. litigated returns.

As illustrated in Figure 4, formulae that are moderately sensitive (0.50 coefficient) to corporate utility bond yields (California or Ontario formula), or government bond yields (the Vermont formula), or calculations of the equity returns such as a prescriptive ROE approach (Mississippi formula) or a formula that tracks U.S. litigated equity returns (the RRA Index) as recommended by Concentric in Alberta and Ontario (50% regression formula and 50% index of average North American litigated returns), provide results most comparable to the directional U.S. litigated returns benchmark.

**Figure 4: Backcast Analysis**




## d. Relative Performance Across Varying Economic and Market Conditions

To better understand how each of the formulas would perform across varied economic and market conditions, we developed a stress test analysis, to identify the formulaic approaches that were more subject to the volatility of inputs and accordingly more prone to instability or outlier results. Concentric conducted this test by varying each of the formulas' inputs by 2 standard deviations above and below its current value to approximate a sustained increase or decrease in the value of the input.[33] For each input, we computed the standard deviation of daily closing values between January 1, 1994 and June 30, 2010. We then ratably grew each input, over a 10-year period, so that by the end of the tenth year, each input variable would be exactly two standard deviations greater than its original value and conversely, two standard deviations less than its original value. We calculated and graphed how each of the formulae would perform under those circumstances in each year of our test period (heavy solid line). Additionally, we computed what the ROE result of each formula would be if long-term forecasts (Consensus Forecasts and Blue Chip) were to be realized. We have plotted this ROE result on the graphs that follow (heavy dashed line) to indicate the formulaic ROE that would be produced by the current long-term forecasts of certain formula inputs.[34]

The general statistics we calculated for each formula input are summarized in Table 3. For each primary input, i.e. U.S. ROE decisions, Bloomberg A-Rated Utility Bonds, Moody's Baa-Rated Utility Bonds, U.S. 10-Year Treasury Bond, and Government of Canada 30-Year Long Bonds, we generated the mean, median, standard deviation, sample variance, range, minimum, and the number of observations for the sample.

33 Daily closing value as of June 30, 2010 except for 'U.S. ROE Decisions' which is a quarterly weighted average

34 Long-term forecasts are not available for the following variables: U.S. ROE Decisions, Moody's Baa-rated Utility Bond Index, Government of Canada 30-year bonds, and Bloomberg Canada A-rated Utility Bond Index. For the Moody's Baa-rated Utility Bond Index, we estimated the spread between the Moody's Index and U.S. Government 30-year Treasury bonds using linear regression (using daily data from 1/1/1994 – 6/30/2010). The resulting linear equation was applied to the Blue Chip forecast of U.S. Government 30-year Treasury bonds to arrive at a forecast estimate of Moody's Baa-rated Utility Bond Indices. For Government of Canada 30-year bonds, we took a similar approach and estimated the spread between 10- and 30-year bonds using linear regression (using daily data from 1/1/1994 – 6/30/2010), which was applied to the Consensus Forecast of Canada 10-year Treasury bonds to arrive at an estimate of the Forecast for the 30-year Government of Canada Bond Yield. Lastly, For the Bloomberg Canada A-rated Utility Bond Index, we estimated the spread between the Bloomberg Index 30-year A-rated Utility Index and the Government of Canada 30-year bonds using linear regression (using daily data since the inception of the Bloomberg index from 3/5/2002 – 6/30/2010), which was applied to the derived forecast of Canada 30-year government bond yields to arrive at a forecast for the 30-year Canadian A-rated Utility Bond Yield.

Table 3: Descriptive Statistics of Formula Inputs

DESCRIPTIVE STATISTICS (January 1, 1994 - June 30, 2010)

| | [A] U.S. ROE Decisions | [B] Bloomberg Canada A-rated Utility Bond | [C] Moody's Baa-rated Utility Bond | [D] U.S. Government 10-year Bond | [E] Government of Canada 30-year Bond |
|---|---|---|---|---|---|
| Mean | 10.91 | 5.81 | 7.38 | 5.08 | 5.65 |
| Median | 10.94 | 5.61 | 7.54 | 4.90 | 5.49 |
| Standard Deviation | 0.53 | 0.62 | 0.94 | 1.18 | 1.49 |
| Sample Variance | 0.28 | 0.38 | 0.87 | 1.40 | 2.23 |
| Range | 2.23 | 2.35 | 3.87 | 5.97 | 6.30 |
| Minimum | 10.03 | 4.86 | 5.58 | 2.08 | 3.39 |
| Maximum | 12.26 | 7.21 | 9.45 | 8.05 | 9.69 |
| Count | 66 | 2,172 | 4,118 | 4,129 | 4,278 |

Notes:

[A] Source: Regulatory Research Associates; quarterly weighted-average authorized ROE for electric and natural gas distribution companies

[B] Source: Bloomberg Professional; daily data available beginning 3/5/2002

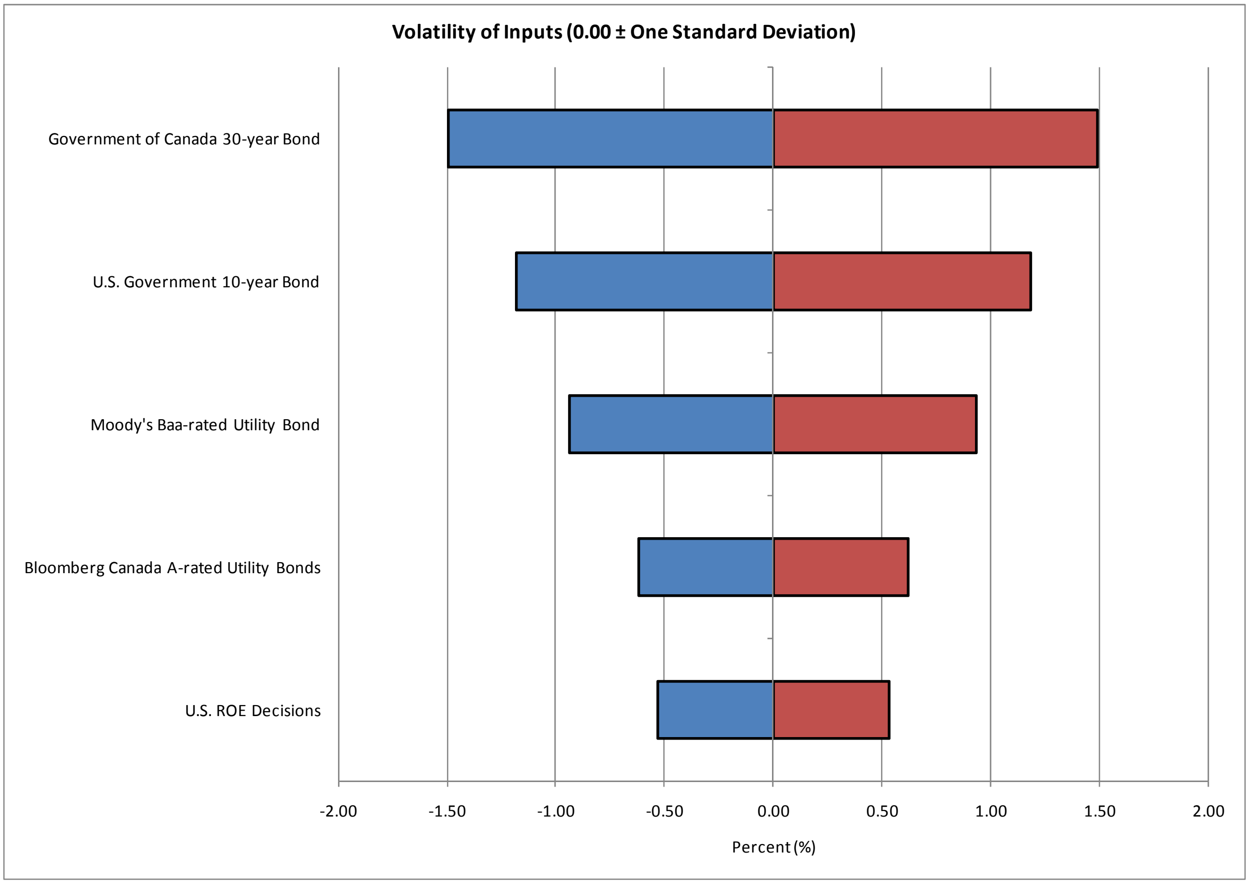
[C] Source: Bloomberg Professional; daily data

[D] Source: Bloomberg Professional; daily data

[E] Source: Bloomberg Professional; daily data

In the statistics above, we can see that the variability of government bond yields, as measured by the standard deviation and the sample variance are much greater than the variability in U.S. ROE decisions or corporate utility bond yields. They also possess the largest percentage point range between the high yield and the low yield of all the samples (5.97 and 6.30 percentage points for the U.S. 10-year bond and the Canadian 30-year bond, respectively). The variability in U.S. ROE decisions is the lowest within the sample of formula inputs with a total range between the high and low ROE percentage of 2.23 percentage points. This is further illustrated in Figure 5, which shows the standard deviation of each input.

Figure 5: Standard Deviation of Formula Inputs

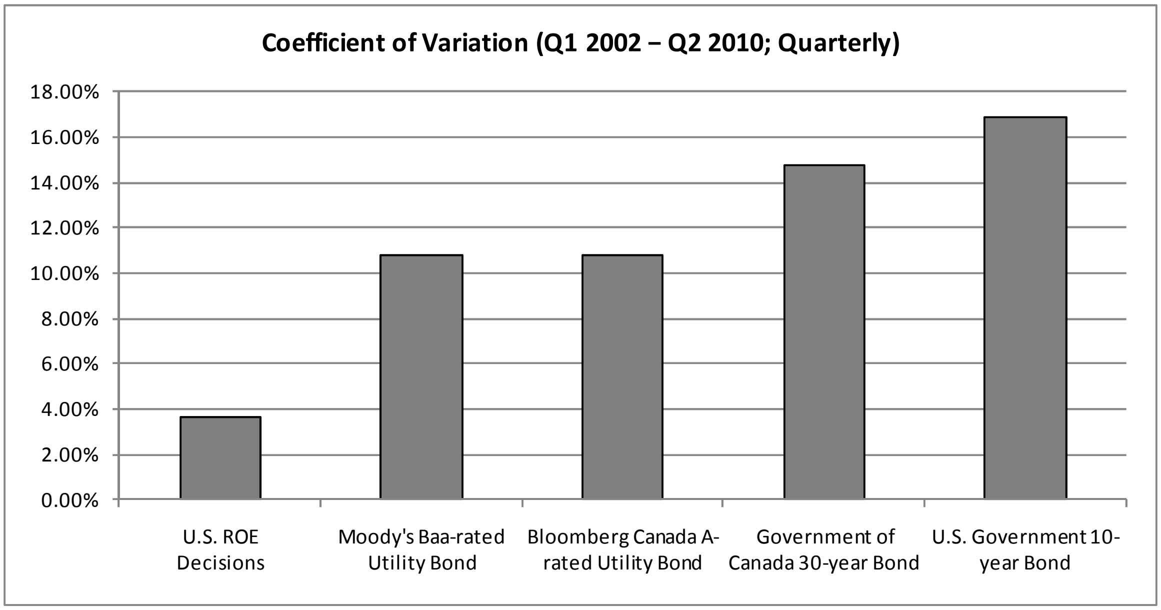



We have further standardized the above volatility measures by dividing by the mean of each of the respective inputs to find the coefficient of variation ("COV"), or the standard deviation relative to the mean, for comparison across all of the inputs. This is a useful way to compare the degree of variation across these inputs, even though their means vary. The lower the COV, the lower the variability in relation to its mean value, implying greater stability in a formula employing this input. Again, we observe that government bond yields are the most volatile of the inputs generally relied upon for ROE adjustment mechanisms[35] and U.S. litigated authorized returns are the least variable.

[35] Notes:

1. 'Coefficient of Variation' equals Standard Deviation / Mean.
2. Time period (Q1 2002 – Q2 2010) dictated by 'Bloomberg Canada A-rated Utility Bonds' which became available March 5, 2002.
3. Quarterly data used for all inputs because 'U.S. ROE Decisions' are only available quarterly. The remaining inputs are available daily, weekly, monthly, quarterly, and annually.

**Figure 6: Standardized Volatility of Formula Inputs – Coefficient of Variation**

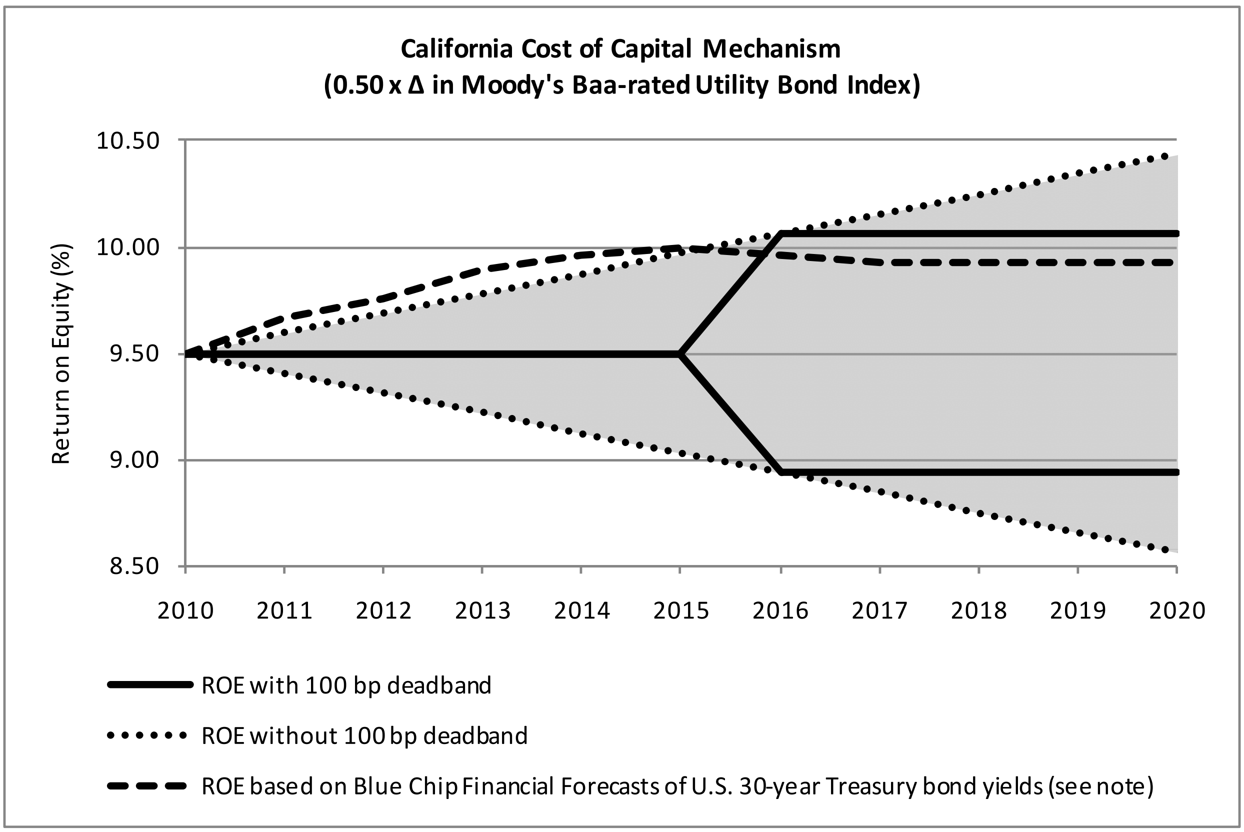



Note: Time period (Q1 2002 – Q2 2010) dictated by Bloomberg Canada A-rated Utility Bond Index which commenced on 3/5/2002.

Results of Stress Test - California

From the 9.5% ROE currently in effect for Terasen today, the shaded area in Figure 7 represents the results of our stress test on the projected inputs in the California ROE adjustment formula. The Moody's Corporate Baa utility bond standard deviation is 0.94. The solid lines below represent the ROE results at each point of the stress test, when employing the 100 basis point deadband; while the fine dotted lines reflect the results of the formula under stress with no deadband. The heavy dotted line represents the ROEs that would result from the long term forecast for these inputs, according to Blue Chip Consensus Economic Forecast. That graph reflects that forecasted corporate bond yields are currently projected to increase by more than that provided by our stress test (1 standard deviation in 5 years; 2 standard deviations in 10 years), hence the forecast falls outside the shaded range in the early and middle years. The Blue Chip Economic Forecast projects that 30-year U.S. Treasury Bond is forecast to grow from 4.5% in 2010 to a high of 6.0% in 2015 and settle at 5.8% towards the end of the ten-year period.

**Figure 7: California Cost of Capital Mechanism Stress Test Range and Forecasted Results**



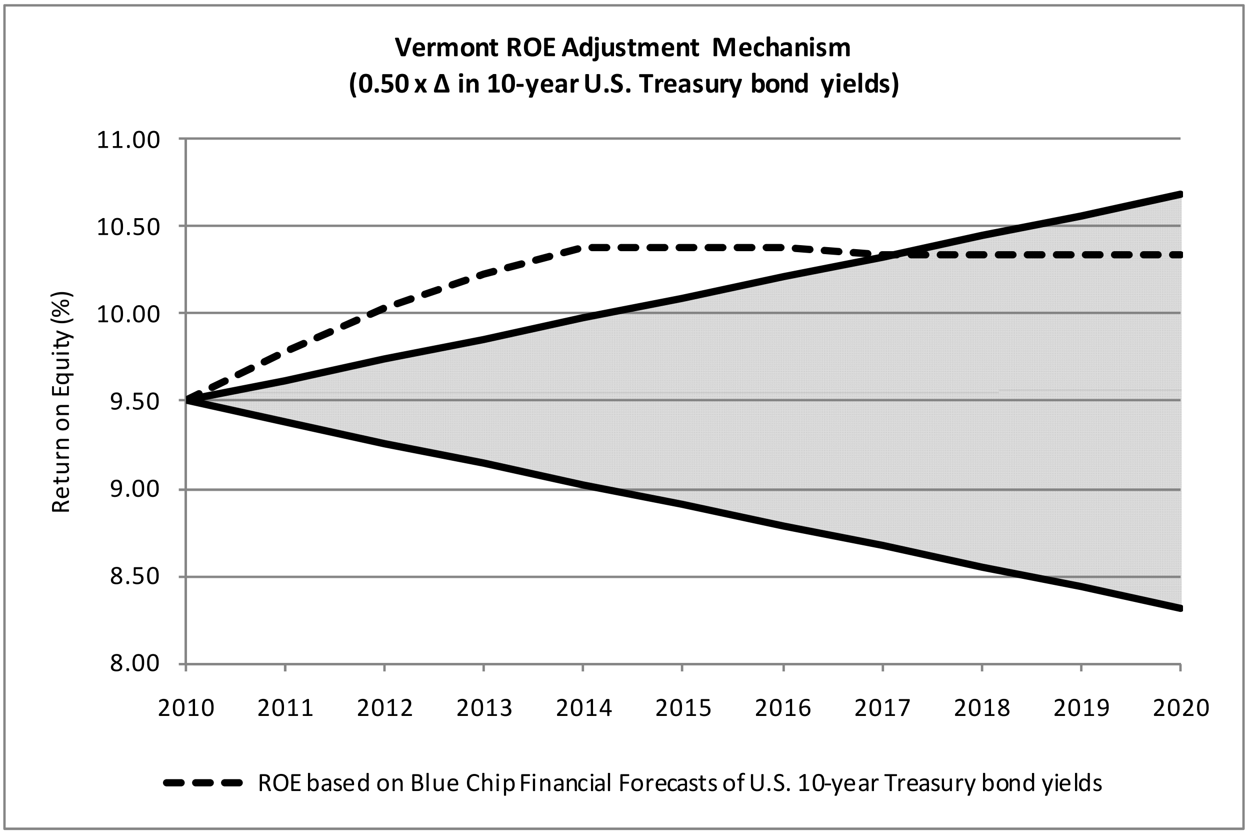

Note: Historical relationship between U.S. 30-year Treasury bond yields and Moody's Baa-rated Utility Bond Index estimated by linear regression and applied to forecasts of U.S. 30-year Treasury bond yields.

.

Results of Stress Test - Vermont

As indicated in Table 3, the standard deviation for the 10-year U.S. government bond yield is 1.18. The solid lines in Figure 8 show the impact of an increase/decrease in the starting bond yield equal to two standard deviations (2.36%) over 10 years. Figure 8 also shows (dotted line) a rapid increase in forecasted government bond yields that cause the projected results to fall outside the shaded range during the early and middle years. Blue Chip Consensus estimates for 10-year U.S. Treasuries climb to a high of 5.5 percent by 2014, from a current value of 2.97 percent as of the end of the second quarter in 2010, settling at 5.4 percent from 2017 through 2020.[36]

**Figure 8: Vermont Cost of Capital Mechanism Stress Test Range and Forecasted Results**

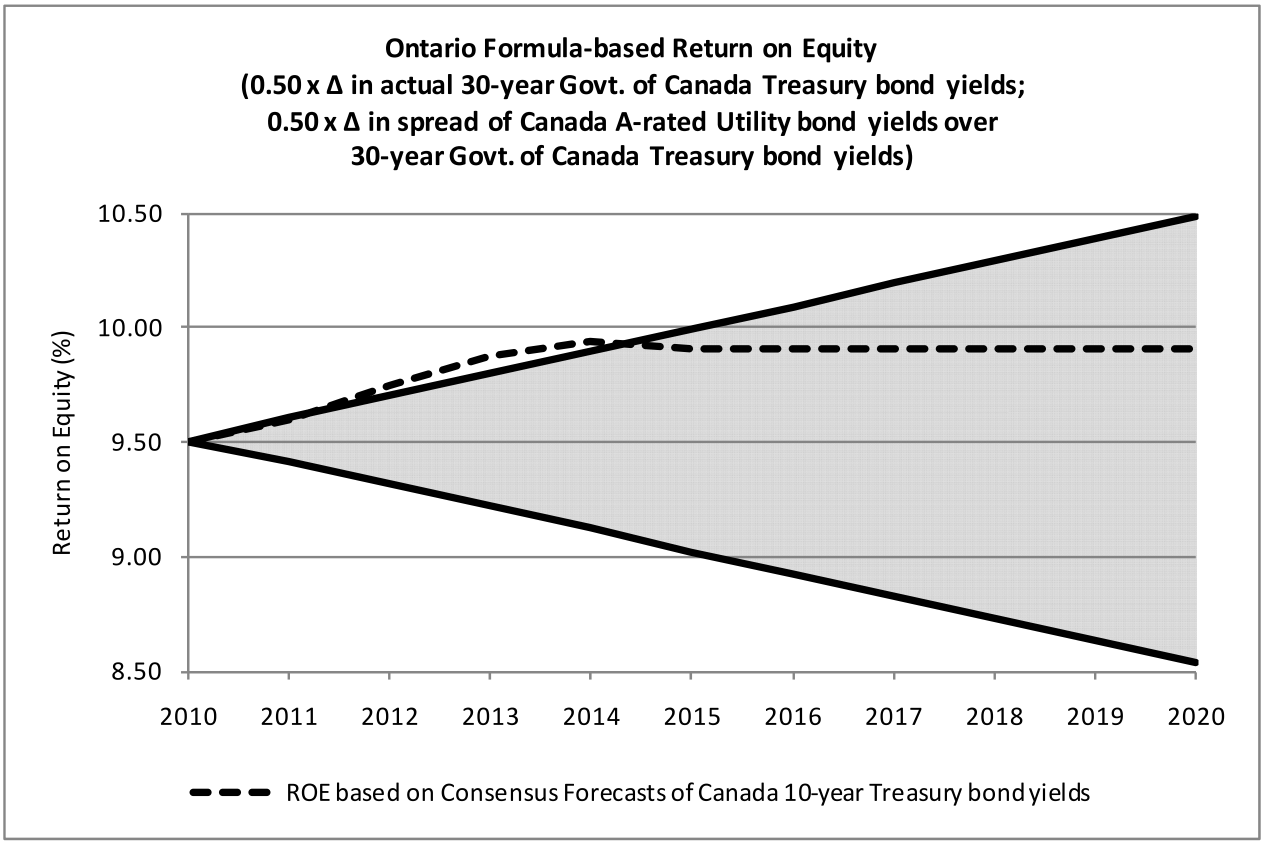



36 Blue Chip Financial Forecasts, Vol. 29, No. 6, June 1, 2010.

Results of Stress Test - Ontario

The current Ontario formula is diagrammed in Figure 9, under stress parameters of 2 x the standard deviation of 1.49 for the 30-year Government of Canada Bond yield, which serves as a basis for the formula. Our forecast projection (dotted line) and stress test (solid lines) are based upon the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[37], plus our estimate of the projected spread between Canada 10-year bonds and Canada 30-year long bonds determined using regression analysis and the following equation ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond)). To that derived 30-year government of Canada bond yield projection, we estimated the projected spread between Canada 30-year long bonds and 30-year Bloomberg A-rated utility bonds using the following linear regression equation: ($Spread_{30,Util30}$ = 2.8297 - 0.3481(Canada 30-year bond)).

**Figure 9: Ontario Cost of Capital Mechanism Stress Test Range and Forecasted Results**



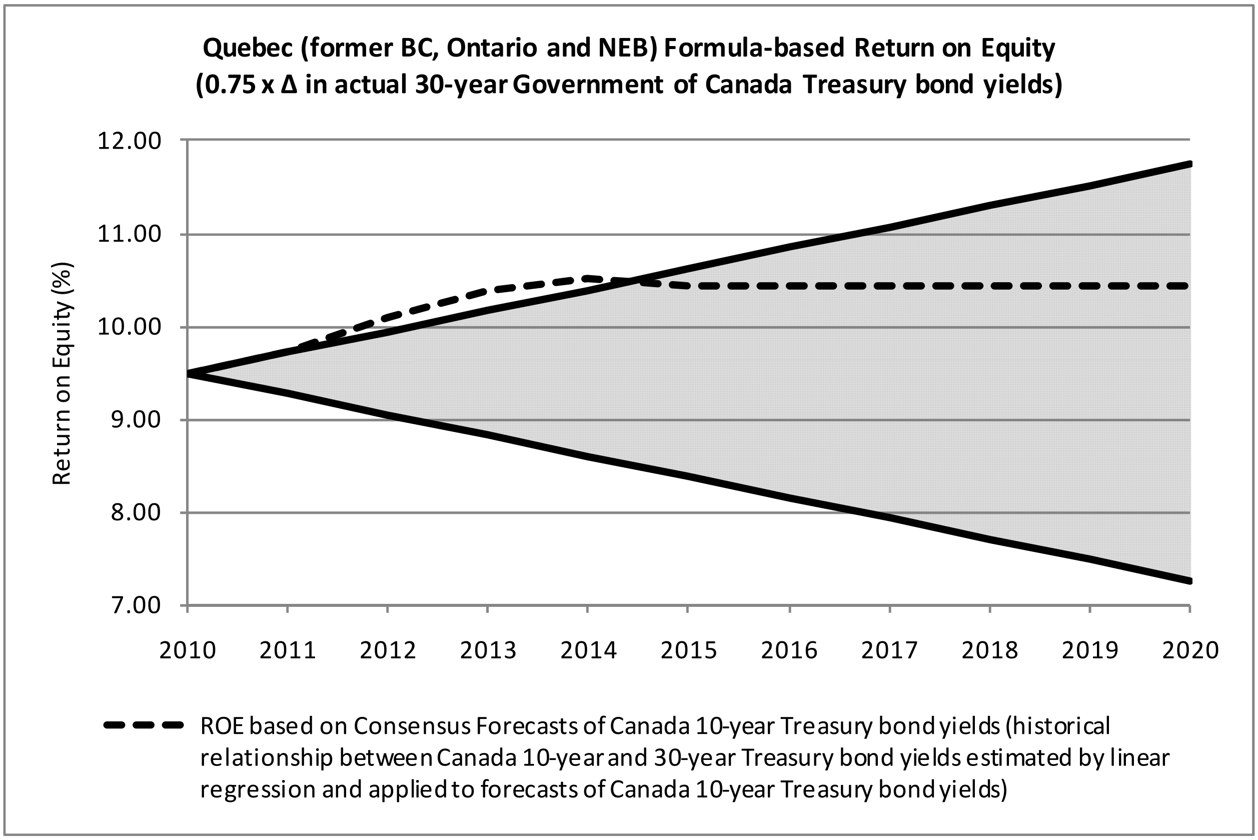

Note: Historical relationship between Canada 10-year and 30-year Treasury bond yields and Canada 30-year Treasury and Canada 30-year A-rated utility bond yields estimated by linear regression and applied to forecasts of Canada 10-year Treasury bond yields.

37 April 2010 long term Consensus Forecast for Canadian 10-Year Treasury Bonds

Results of Stress Test –Quebec (former BC, Ontario and NEB formula)

Similarly, we modeled the former BC formula under stress parameters of 2 x the standard deviation of 1.49 for the 30-year Government of Canada Bond. Our projection and stress test is based on the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[38] plus the estimated spread between Canada 10-year bonds and Canada 30-year long bonds determined by the linear regression analysis ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond).

**Figure 10: Quebec (former BC, Ontario and NEB) Cost of Capital Mechanism Stress Test Range and Forecasted Results**

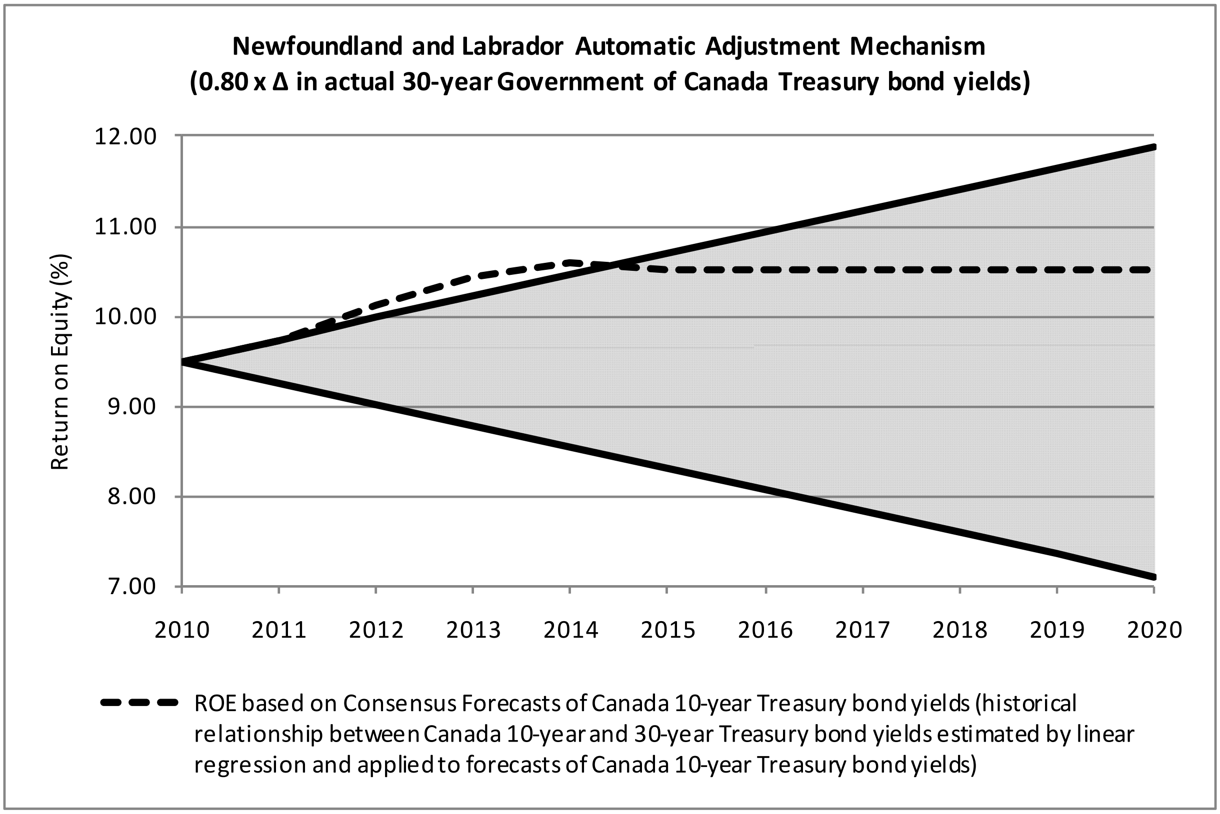



38 Ibid.

Results of Stress Test – Newfoundland and Labrador

Similarly, we modeled the Newfoundland and Labrador formula under stress parameters of 2 x the standard deviation of 1.18 for the 10-year Government of Canada Bond. Our projection and stress test is based on the Consensus Economics long term 10-year long bond forecast (projected to increase from 3.8% in 2010 to 5.1% in 2020)[39] plus the estimated spread between Canada 10-year bonds and Canada 30-year long bonds determined by the following linear regression equation: ($Spread_{10,30}$ = 0.4889 - 0.0299(Canada 10-year bond)). Those results are presented in Figure 11.

**Figure 11: Newfoundland and Labrador Cost of Capital Mechanism Stress Test Range and Forecasted Results**

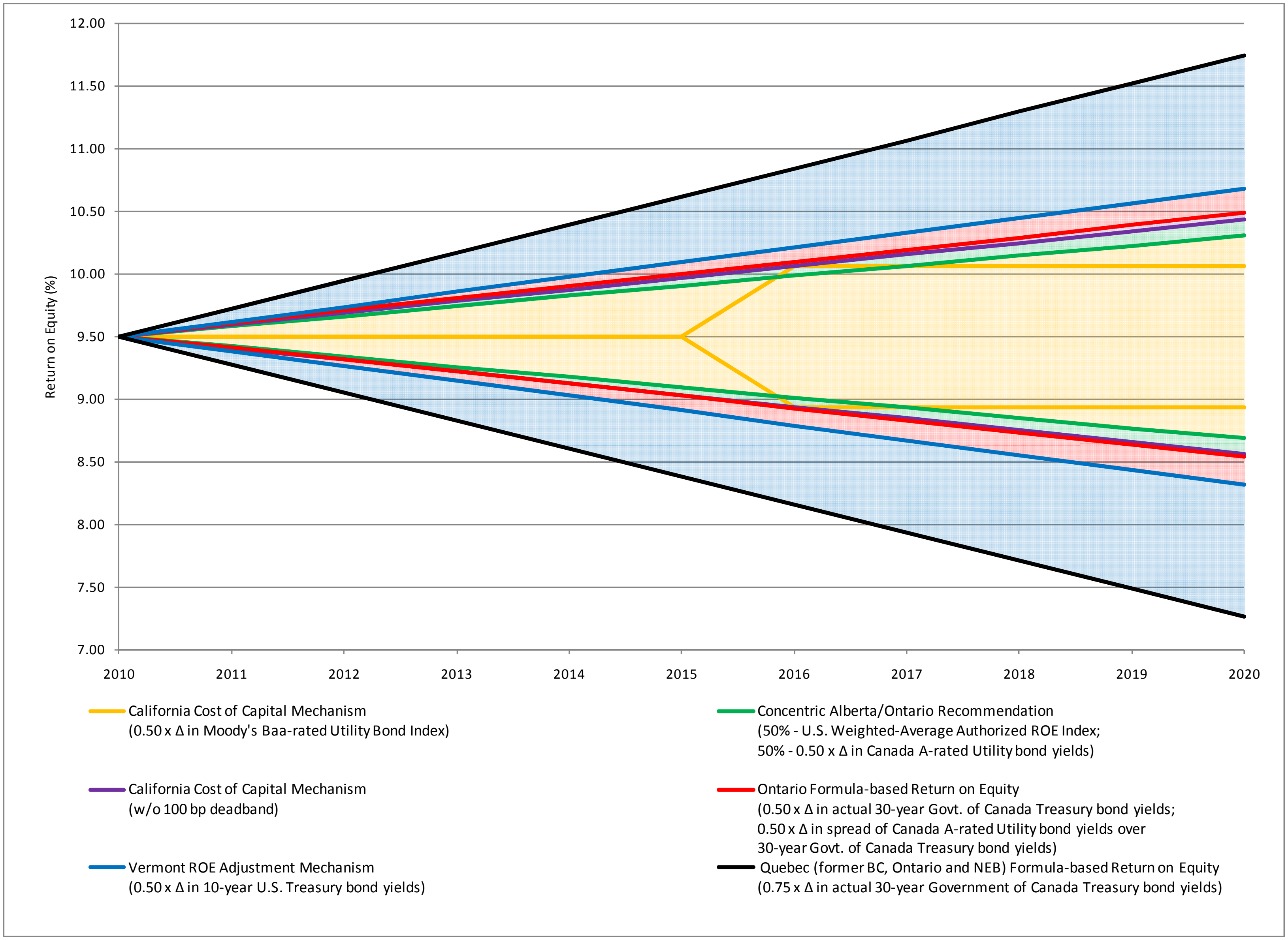



Stress Test Summary

The range of formula outcomes from applying the stress test of two standard deviations is pictured in Figure 12 for each of the formulas reviewed. We have found that a formula based on utility bond yields with a 50% adjustment factor (as is the case in California, Ontario, Vermont and that proposed by Concentric in the OEB and Alberta ROE proceedings which employed an equal weighting of the movement of the RRA index with an adjustment formula based upon Canadian utility bond yields, with a 50% adjustment factor) display the least variation in predicted outcomes based on historic volatility. The current Ontario formula introduces slightly greater volatility as a result of its reliance on the government bond yield to which the spread between the government bond yield and the Bloomberg Canadian A-Rated utility bond yield is added. Those formulae with a high sensitivity to government bond yields display the greatest range of outcomes, and also the most rapid increases in ROEs based on forecast increases in government bond yields (denoted by the heavy dashed lines in each preceding chart).

39 Ibid.

**Figure 12: Stress Test Range of ROE Outcomes for all Formulae**



### e. Transparency and Data Availability

Regulatory transparency refers to the general understanding of the ROE setting process and the predictability of outcomes. This is an advantage of the formulaic approach to determining ROE over the litigated ROE process where regulatory outcomes are difficult to predict. A formulaic ROE that can be estimated by stakeholders promotes regulatory transparency as investors know how the utility's returns will be determined and may be able to make forward projections on that basis. Consumer interests can also gauge future rate impacts. A formula that invites regulatory tinkering in its application would not satisfy the objective of regulatory transparency. Any formula that is selected should utilize data that is commercially available. Often, subscription charges apply to the most widely-used data services (e.g., Consensus Forecasts, Bloomberg, Value Line, SNL, I/B/E/S, Thomson, DEX Universe Bond Indices, Moody's), but these costs may be more than offset by the value of the data to the process. Generally, government bond yield data are publicly available, as is dividend data on all publicly traded issues in the U.S. and Canada. Authorized ROE data are publicly available through Board Orders, or subscribing to a research service similar to Regulatory Research Associates (owned by SNL data) that performs this research. Generally, SNL research focuses on U.S. companies and we are not aware of a similar data service for Canadian utilities. Earnings growth rates and betas typically require a subscription to Value Line or Bloomberg, though Bloomberg provides international coverage, while Value Line focuses on companies traded on American stock exchanges. Corporate bond yield indices are often proprietary.

The three primary sources of bond yield data are: Bloomberg, Moody's and DEX by PC Analytics. The following is a brief summary of these data series and sources.

<u>Bloomberg</u> develops a Fair Value Canada 30-Year A-rated Utility curve which is extrapolated from the yields of Canadian A-rated utility bonds at their various maturities. The curve is constructed by applying specific points for various bonds of certain maturities to the curve, adjusting for any mismatch. This curve is updated daily based on the valuations of the securities which comprise the basis for the curve. As each of the bonds rolls down the curve new longer maturities are added. Though these curves are derived, our analyses in Figures 13 and 14 below show that the Bloomberg Fair Value Curve is a reasonable proxy for an actual Canadian bond index, based on A-rated bonds with maturities of 20-30 years.

<u>Moody's</u> provides long term corporate bond yield averages that are derived from pricing data on a regularly replenished population of corporate bonds in the U.S. market, each with current outstanding bond issuances over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, or if the bonds are susceptible to redemption, or if their ratings change. All yields reflect yield to maturity calculated on a semi-annual basis. Each observation is an un-weighted average. The average corporate bond yield index represents the average of the corresponding average Industrial and Average Public Utility observations.

<u>DEX – PC Bond Analytics PC-Bond*</u> publishes indices to measure the performance of the Canadian fixed income market. Indices are exclusively Canadian and are widely relied upon for Canadian fixed income performance benchmarks. The Universe Bond Index tracks the broad Canadian bond market for all Canadian corporate bond issuances and is further

divided into sub-sectors based on major industry groups: Financial, Communication, Industrial, Energy, Infrastructure, Real Estate, and Securitization. These sectors may also be sub-divided based on credit rating: a combined AAA/AA sector, a single A sector, and a BBB sector; and/or term, which is classified as short (1 – 5 years), mid (5 – 10 years), and long (10 + years). Eligibility requirements include $100 million minimum issues size and investment grade credit rating, among others.

In addition, DEX provides a 20+ Universal Bond Index which includes all corporate bond issuances within a particular credit sector with remaining maturities in excess of 20 years. Eligibility requirements are as stated above. Though this bond index encompasses long term maturities, it is not subdivided by credit rating.

The Universal Bond indices are built with daily history, calculated and available from December 29, 2000 and are published daily. These are also transparent indices, with individual security holdings and prices, disclosed electronically each day. We understand that DEX and PC Bond Analytics tailors its subscription prices to their clients' requirements and price their product accordingly. Concentric's inquiry to pricing indicated a fee of $2,500 for a one-time snap shot of constituents making up the sub-sector "energy" index, and a one-time fee of $1,500 for a complete historical data stream for any one bond index data series requested. We also note that the Company is very restrictive in the use of its data to protect its propriety.

Below we have provided a comparison of the three price series relative to one another for both utility bond indices and corporate bond indices. As the figures below demonstrate, the Bloomberg Fair Value Curve and the DEX PC Bond Analytics Universe curve, both representing Canadian bond yield indices for the utility and energy sectors, respectively, are nearly identical, and accordingly, we conclude that these series are reasonable substitutes for Canadian utility bond yields. The Moody's utility data suggests that the U.S. bond indices and Canadian utility bond indices have diverged in the past, though today all three indices provide similar yields for utility bonds.

Turning to Figure 13, though the corporate bond yield data among the three indices generally move in tandem, we believe the utility bond index (as available in Bloomberg or DEX) is preferable for purposes of adjusting utility equity returns in Canada.

Figure 13: Moody's, Bloomberg, DEX Comparison of Utility Bond Indices

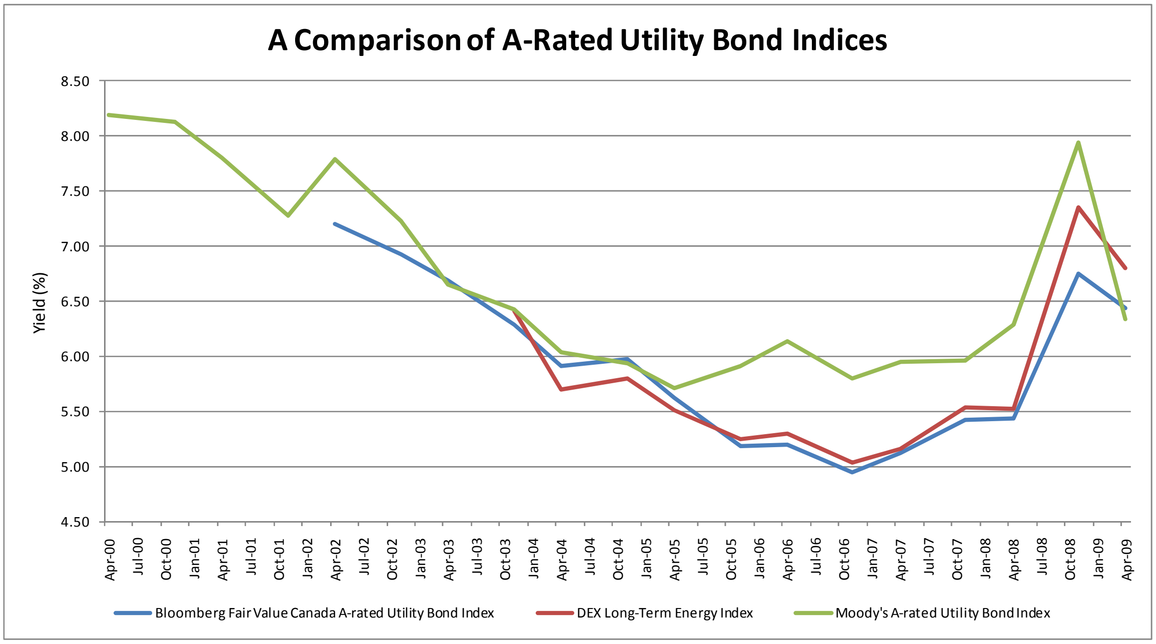
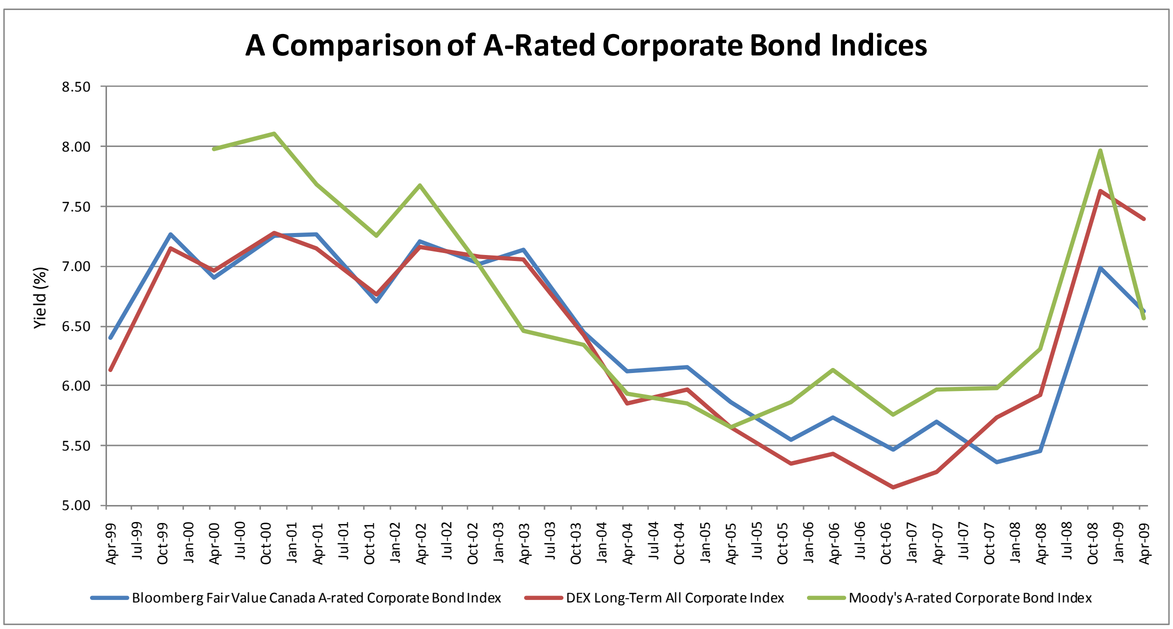



Figure 14: Moody's, Bloomberg, DEX Comparison of Corporate Bond Indices




## 4. Potential Approaches for British Columbia

In response to the BCUC's December 2009 Order, Concentric has researched and evaluated alternative ROE automatic adjustment mechanisms. In doing so, we have examined formulas used in other North American jurisdictions, selectively researched overseas, and we have also considered other alternatives. Though Concentric is not recommending a formulaic approach, we have identified attributes to be considered should the Commission determine in a future proceeding that a new formula will be adopted in BC. Further, we have examined alternative inputs and parameters used to construct formulas, and compared how these formulas perform over time against non-formulaic results and under varying market conditions. Based on this assessment, we have identified several potential options for a formulaic adjustment mechanism. These approaches vary in terms of their complexity and ease of administration. The first three are indexed based; the last is a more complex multifactor model. Finally, the BCUC may elect to have periodic litigated proceedings (with the potential for settlements) on this matter. Each is described below.

All of the formulaic methodologies provided below could be used to establish a generic benchmark for a low risk, high grade utility, to which adjustments are made to account for risk of a specific utility relative to the benchmark (as is the historic practice in BC); or alternatively could be applied to utility specific ROEs where the base ROE is set specifically for each utility and adjusted in accordance with the AAM (as is the practice in California).

**(1) Utility Bond Yield Index**

As a general premise, the straight utility bond index is simple to understand and administer and closely resembles the prior BC model, with the substitution of utility bonds for government bonds and a reduced sensitivity to changes in bond yields. Ontario adopted a variation of this approach, which used forecast government bond yields and utility bond spreads (over government bonds) to project utility bond yields.

The general specification for this formula is:

Index: average yields on long term utility bonds of comparable grade to the target utility
- California utilizes the 12 month moving average Moody's Baa or A, depending on the utility rating.
- Ontario utilizes the utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield, plus the change in the forecast long Canada bond.
- Concentric observes that the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond yield and the DEX alternative move in close proximity, and either should be a reliable indicator of long-term Canadian utility bond yields.

Formula Coefficient Adjustment Factor of 50% - based on the historical relationship between utility bond yields and regulatory authorized returns. For every one percentage point movement in the utility bond yield index, the authorized return will move in the same direction by 50 basis points.

Deadband: none (but could be established)
Trigger Mechanism: none (but could be established)
Term: 3 – 5 years

As a numeric example, the California specification of this model is as follows:

$$ROE_n = ROE_{n-1} + 0.50 \times (\text{Moody's } Baa_n - \text{Moody's Baa benchmark})$$

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, the new ROE is:

$$ROE = 9.5 + 0.5*(6.0 - 5.0) = 10.0\%$$

**(2) Utility Bond Yield Index with a Deadband and Trigger**

A variation of the above simplified bond index approach incorporates a deadband mechanism, as we have seen in California, and potentially a trigger mechanism. The deadband can be used to negate the impacts of smaller changes in the annual bond index, while a trigger can be used to signal a large change from a specified benchmark warranting re-examination of the formula. These features serve as "rails" on the results from the formula.

Index: Similar to the California and Ontario approaches, ROE is indexed to the average yields on long term utility bonds

Formula Coefficient Adjustment Factor of 50%, as above.

Deadband: 50 basis points – To avoid the need to make adjustments to the return portion of the cost of service for small changes in ROE, a deadband may be adopted so that only significant changes from the benchmark lead to a change in authorized return. If the change in the bond yield index is within 50 basis points of the original benchmark, no adjustment to ROE is made. If the bond yield index exceeds the original benchmark by greater than 50%, ROE would be adjusted accordingly and the new bond yield would become the new benchmark. Concentric believes that 50 basis points is a threshold that provides a reasonable balance between regulatory efficiency and providing a return that is reflective of prevailing equity markets.

Trigger Mechanism 100 basis points: A review of the formula is triggered in the event that the formula produces results that are outside plus or minus 100 basis points of a given benchmark. Concentric suggests that the benchmark should be established as the average awarded ROE ("AAROE") for all major Canadian[40] and U.S. gas and electric utilities for the preceding 12 month period. As described earlier, the data for U.S. utilities is readily available through SNL's RRA database. Canadian utility ROEs would be added to this data through an annual review of commission orders for major utilities. To make this trigger non-circular, it would be set only taking into account litigated (non-formulaic) ROE awards. When applying a trigger mechanism, it should be sufficiently wide so as not to trigger a review at the onset of the formula, or alternatively could be calibrated to consider the opening differential between the AAROE benchmark and the utility authorized ROE at the onset.

Term: 3 – 5 years

[40] Except those operating under the prior Canadian formula linked to government bond yields.

As a numeric example, the basic model is:

$$ROE_n = ROE_{n-1} + 0.50 \times (Moody's\ Baa_n - Moody's\ Baa\ benchmark)$$

To account for the deadband:

If *(Moody's* $Baa_n$ *– Moody's Baa benchmark)* is less than 0.50, then no change to ROE

If greater than .50, then:

$$ROE_n = ROE_{n-1} + 0.50 \times (Moody's\ Baa_n - Moody's\ Baa\ benchmark)$$

$$Moody's\ Baa_n = New\ Moody's\ Baa\ benchmark$$

And, to account for the trigger:

If *ROEn* is greater or lesser than AAROE +/- 1.0%, then a review of the formula is triggered.

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, the new ROE is:

ROE = 9.5 + 0.5*(6.0 – 5.0)= 10.0%

If AAROE is 9.25%, no review of the formula is triggered.

**(3) Combined Utility Bond Yield and Average Awarded ROE Index**

The intuitive appeal of this approach is equal weighting of the historic Canadian formula (with utility bond yields replacing government bond yields and an updated coefficient of 0.50), and an index of average awarded ROEs in litigated proceedings in Canada and the U.S. It remains relatively straight forward, and captures more information on required investor returns (assuming awarded returns are a reasonable proxy for required returns) than a pure bond related index.

Index: ROE is indexed to the weighted average of average yields on long term utility bonds (as described above) and the AAROE.

Weighting: 50% Bond Yield Index / 50% AAROE Index

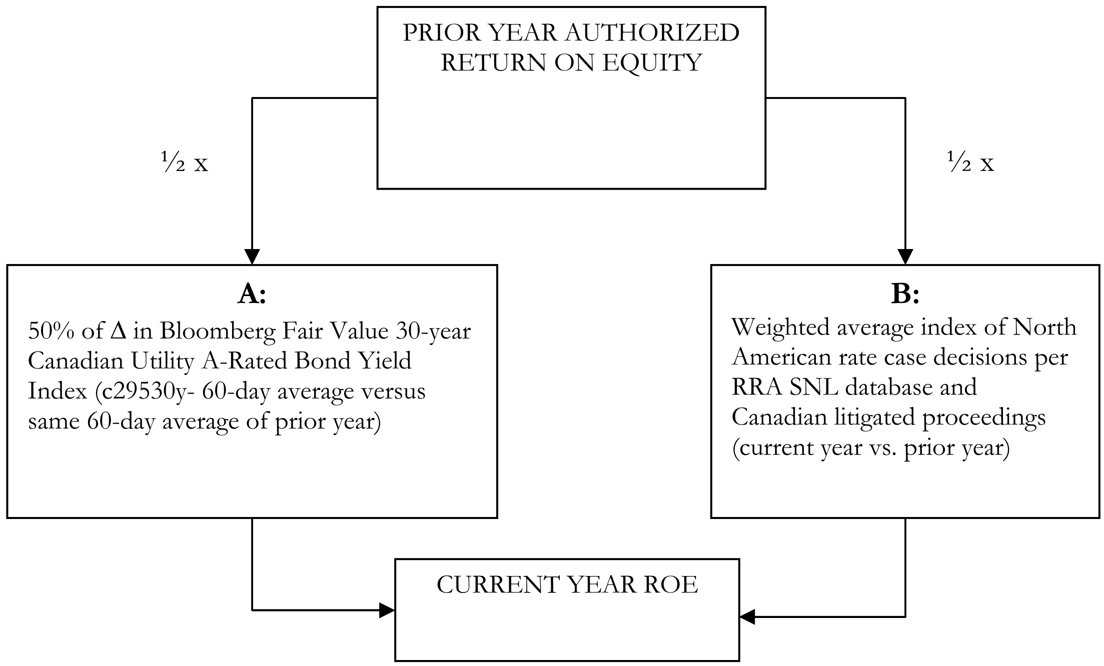
Adjustment Factor: 50% for Bonds, 100% for AAROE

Trigger Mechanism: none

Deadband: none (but could be established)

Term: 3 – 5 years

A diagram of the formula follows:




A numeric example of this formula is:

$$ROE_n = .5\ [ROE_{n-1} + (0.50 \times (Can\ Util\ Bond_n - Can\ Util\ Bond_{n-1})] \ + .5\ [ROE_{n-1} \times (\ AAROE_n / AAROE_{n-1})]$$

So, if the starting ROE (n-1) is 9.5%, and the utility bond yield increases from 5% to 6%, and the index of average awarded ROEs increases from 10.0% to 11.0%, the new ROE is:

ROE = .5 [9.5% + .50(6.0 – 5.0)] + .5 [9.5% (11.0/10.0)] = 10.225%

Intuitively, because of the inclusion of the awarded ROE index which fell further than the bond yield driven formula, and equal weighting of these results, the new ROE falls in between the two results (10.0% vs. 10.45%) at 10.225%. The use of a deadband is a judgment call, but a trigger mechanism in this case is not deemed necessary because of the inclusion of an average awarded ROE term in the formula.

**(4) Multiple Method Model**

Recognizing that simple models based on one or two inputs may not adequately reflect required returns for utility equity investors, it is possible to create the results from standard estimation techniques employed by cost of capital experts. Rather than scrutinizing the methodologies of competing experts, ROE is estimated based on a predetermined set of methods and inputs. This is analogous to the Mississippi model and proposed NY state framework, and similar to the methodology adopted by FERC. Concentric has adapted a variation of those approaches in this model. The selection of specific inputs and the choice of methods to include in this multi-method model would require further refinement, but the general approach would be as follows.

Determinants:

Proxy Group selection criteria

- North American utilities
- Publicly traded
- Pays dividends
- Primarily regulated utility business (>60% total consolidated revenues)
- Differentiated for gas or electric according to primary business (>60% of regulated utility revenues)
- Comparable credit rating (1 notch above or below is an appropriate guideline)
- No announced significant M&A activity

Discounted Cash Flow Model (DCF)

- The current dividend yield for each company in the proxy group is calculated using the annualized current dividend divided by the average stock price for the most recent 90-trading days. The dividend yield for each proxy group company is increased by one-half of the projected growth rate to reflect the expected growth in dividends over the coming year.
- Earnings growth estimates are averages of the estimates for each of the proxy companies (as available) from Bloomberg, Value Line, Zacks, and Thomson First Call.
- DCF computed as the average for each company in the proxy group.

Equity Risk Premium Model (ERP)

- Risk free rate from the forecasts of U.S. and Canadian 30-year bond yields by taking the average of the 3-month and 12-month forecasts of the respective 10-year government bond yields, as reported in the most recent Consensus Forecast issue. To the forecast of the respective 10-year government bond yield, add the daily average historical spread between 10-year and 30-year bonds for the most recent [30] days. This results in the 30-year bond yield forecasts for the U.S. and Canada in each country's native currency [which are then averaged].
- Market equity risk premium (MERP) from Morningstar Ibbotson, arithmetic mean, average of the long term MERP calculated for the U.S. and Canada
- Utility risk differential calculated based on one of three methods:
    - Historical differential between a broad base of utility stock returns (e.g., Moody's Utility Stock Index) and the broader equity market,
    - Awarded returns in North American litigated proceedings (AAROE) vs. the risk free rate, or
    - The CAPM specification of the ERP, using average adjusted betas for the proxy group from Bloomberg and Value Line, as available.

Weights: 50% DCF / 50% ERP

Trigger Mechanism: none

Deadband: none (but could be established)

Term: 3 – 5 years

A numeric example of this approach is:

$ROE_n = .5 \times DCF + .5 \times ERP$

Thus, if the DCF model produces an average of 11.25% for the proxy group, and the ERP produces 8.75%, the new ROE is set as follows:

ROE = .5 (11.25%) + .5 (8.75%) = 10.50%

There are many variations of this method that could be specified. The DCF could be computed using single-stage, two-stage, or sustainable growth specifications, or taken as an average of these methods. Similarly, the ERP could be computed using all three sources for equity risk premia mentioned above, or extended with the empirical CAPM model (ECAPM). Using multiple methods increases the complexity of the approach, but provides more confidence that the results would emulate those calculated by experts using a variety of methods to bracket the ROE estimate.

**(5) Periodic Rate Proceedings**

Concentric's research indicates most North American jurisdictions do not rely on a formula for setting the utility cost of capital. Cost of capital is typically set during the course of litigated rate proceedings where company and stakeholder witnesses present independent estimates and the Commission weighs the evidence and determines the fair ROE. Within this approach, several variations are possible:

- Fixed schedule for reset - typically coinciding with a fixed rate application schedule (e.g., annually, bi-annually, etc.)
- Request of the parties - the utility, Commission, or stakeholders may request a rate hearing, including cost of capital, as changed circumstances warrant
- Settlement - the parties may agree to hold rates fixed for a certain period of time, including cost of capital, unless unforeseen market circumstances cause a re-hearing.

The advantage of this approach is its adaptability to changing market conditions, the periodic input from stakeholders, and the ability of the Commission to act on updated capital market information. Generally, ROEs are not volatile over time and in the case of many utilities, periodic rate hearings provide a sufficient response to changing market conditions while retaining stability and predictability in returns. Drawbacks include the additional resources required for litigated cost of capital proceedings, the potential politicization of ROE determinations when other rate pressures emerge, and the potential for companies to remain out of hearings when costs are decreasing.

## 5. Conclusions

In this report we have examined the utilization of ROE formulas in other jurisdictions and found that a formulaic approach has been selectively adopted by regulatory commissions in Canada and with less frequency in the U.S. In Canada, three provinces remain on a formula (ON, QC and NL). In the U.S., three states have adopted a formula (CA, MS and VT). In addition, Virginia and Florida utilize formulas to establish a range of reasonableness for ROE, as does the FERC with its prescribed ROE methodology. Connecticut is currently investigating the use of a formula.

Formulas adopted in these jurisdictions range from relatively simple models (e.g., the traditional Canadian government bond yield, California's utility bond yield, or Ontario's hybrid of these two), to the more complex multi-method approach adopted in Mississippi. Concentric has evaluated several of these alternatives, a method Concentric has recommended elsewhere, and the prior BC formula. We have compared backcast results with a benchmark of U.S. litigated returns and authorized returns for Terasen, and "stress-tested" the results using the underlying volatility of each model's inputs. Of those we have evaluated using a backcast, the Concentric approach would have come closest to yielding the authorized return by the BCUC in December 2009, assuming this formula was adopted in 1994. The California and Mississippi approaches come closest to the litigated return benchmark over time.

The stress tests suggest that the California and Concentric models are the least volatile, based on the historic standard deviations of the model inputs. Conversely, the Quebec formula (and the prior BC, Ontario and NEB formulas) and the Newfoundland and Labrador formula are the most volatile, due to the greater standard deviations of government bond yields in contrast with other model inputs, and a higher sensitivity to those inputs.

The Commission did not direct Terasen to provide a recommended formula, but rather to "complete a study of alternative formulae and report to the Commission by December 31, 2010." In Concentric's view, this study accomplishes this objective. Each of the four specific formulas described in Section 4 are potential candidates should the Commission elect to adopt a new formulaic approach to ROE. The fifth option, periodic rate hearings, will yield the actual results that a formulaic methodology attempts to emulate and is most likely to meet the Fairness Standard. Based on Concentric's assessment of the ability of each approach to meet the desired attributes discussed earlier, and if the Commission deems it appropriate to reintroduce the formula at a later date, Concentric recommends that the Commission make its determination in consideration of the options presented in Section 4.

| INPUTS | ADVANTAGES | DISADVANTAGES |
|---|---|---|
| Forecast 10-Year Government Bond Yield | • Widely available<br>• Historical relationship between government bond yields and utility equity returns<br>• Forward looking | • May significantly depart from corporate equity returns - no equity market input<br>• Significantly influenced by national monetary policy and broad macroeconomic trends.<br>• 10-year horizon is not sufficiently long to parallel corporate asset investment horizon (requires a increment to bring the life to 20 to 30 years – could result in mismatching of forecast and historical data)<br>• Not specific to utilities |
| Historical Avg. 10-Year Government Bond Yield | • Widely available<br>• Historical relationship between government bond yields and utility equity returns | • May significantly depart from corporate equity returns - no equity market input<br>• Significantly influenced by national monetary policy and broad macroeconomic trends.<br>• 10-year horizon is not sufficiently long to parallel corporate asset investment horizon (requires a increment to bring the life to 20 to 30 years – could result in mismatching of forecast and historical data)<br>• Historical performance may not be indicative of future – i.e. not forward looking<br>• Not specific to utilities |
| Bloomberg historical 30-Year A-rated Utility Bond Yield | • Historical relationship between corporate utility bond yields and utility authorized equity returns.<br>• Less subject to governmental monetary policy and broad macroeconomic trends.<br>• Appropriate investment horizon of 30 years<br>• Data available for both U.S. and Canadian Bond Yields<br>• Derived from frequently updated fair value curve Specific to utilities | • Requires a Bloomberg subscription<br>• Stringent data protection requirements<br>• Not forward looking<br>• Utility bond yields are not always a good predictor of utility equity returns – no equity market input |

| INPUTS | ADVANTAGES | DISADVANTAGES |
|---|---|---|
| Moody's 30-year Baa or A-rated utility bond yield | • Historical relationship between corporate utility bond yields and utility authorized equity returns<br>• Less subject to governmental monetary policy and broad macroeconomic trends.<br>• Appropriate investment horizon of 30 years<br>• Specific to utilities<br>• Widely available for nominal cost – does not require an expensive subscription | • Not forward looking<br>• Utility bond yields are not always a good predictor of utility equity returns – no equity market input<br>• Heavily weighted towards U.S. utilities |
| Coefficient for Change in Bond Yields of 0.75 | • Easily administered<br>• Regulatory transparency | • Overstates impact of historic interest rate fluctuations on utility equity returns, and may change over time<br>• Not supported by regression of utility allowed equity returns and government or corporate bond yields |
| Coefficient for Change in Bond Yields of 0.50 | • Easily administered<br>• Regulatory transparency<br>• Supported by regression of utility allowed equity returns and government or corporate bond yields | • Bond yields, alone, cannot fully explain movements in equity markets |
| Prescriptive and equal weighting of DCF, CAPM and Risk Premium Approach | • Provides a prescriptive approach to recalculating ROE each year<br>• Specific to utilities and equities<br>• Based on actual equity calculation using commonly applied methods and inputs<br>• Eliminates the controversy around ROE inputs (i.e. risk premium, beta, growth rates) | • More difficult to administer<br>• Inputs can be viewed as subjective and require subscriptions to data services<br>• Data limited to publicly-traded, investor-owned utilities followed by analysts |
| Weighting of U.S. RRA Index and Canadian Litigated Returns | • Moderately easy to administer<br>• Provides some regulatory transparency<br>• Specific to utilities and incorporates measures of allowed returns on equity (i.e. equity market inputs)<br>• When weighted with Utility bond yields, provides assurance that divergence in equity market from bond market will be at least partially accounted for in the formula result. | • Commissions reluctant to use decisions from other commission in their ROE determinations<br>• Requires reliance on U.S. data<br>• Requires subscription to SNL to develop index, i.e. data is not widely available<br>• Requires Canadian ROE Decision research |

| INPUTS | ADVANTAGES | DISADVANTAGES |
|---|---|---|
| Deadband | • If set properly will avoid frequent and temporary adjustments to ROE - reduces volatility in earnings and rates<br>• Facilitates regulatory expediency by less frequent changes to ROE. | • If not set appropriately may be too sensitive to changes in inputs requiring frequent ROE updates; or conversely be too unresponsive to market inputs |
| Ceiling and Floors | • Provides certainty that the formula returns will not result in unusually high or low ROE estimates. | • Transfers a portion of market risk from ratepayer to shareholder |
| Trigger Mechanism | • Provides certainty that significant movements in ROE will be reviewed and the formula's ability to adequately track returns will be reassessed. | • May not adequately address the period for which the formula should be reviewed, i.e. may require review when not needed and not trigger a review when it is needed.<br>• Trigger mechanisms are often set improperly, i.e. changes in ROE do not necessarily translate to ROEs that are inappropriately low or high. |
| Specified Review Period | • Provides certainty that ROE will be reviewed/ rebased if necessary, and the formula's ability to adequately track returns will be reassessed. | • May not adequately address the period for which the formula should be reviewed, i.e. may require review when not needed and not trigger a review when it is needed. |

# Appendix J

# TABLE OF CONCORDANCE

| | | |
|---|---|---|
| **TABLE OF CONCORDANCE<br>FOR "OTHER FILING REQUIREMENTS"** | | |
| **ROE Matters:** | | |
| 1. | Proposed Benchmark ROE going forward from 2013 and, if applicable, beyond. | • Summary of requested ROE and capital structure for FEI<br>  ○ FBCU Evidence, Section 2.4, pp. 23-24<br>• Summary of expert evidence supporting requested ROE and capital structure for FEI<br>  ○ McShane Evidence, Summary of Conclusions, pp. 5-7<br>  ○ Vander Weide Evidence, Summary and Recommendations, Section VIII, pp. 49-51<br>  ○ Engen Evidence, pp.12,68-69 |
| 2. | Business risks faced by a utility in British Columbia.<br>a) Present business risks:<br>i. itemized listing of each risk with full explanation,<br>ii. significance and impact of each risk to a utility,<br>iii. ranking of the business risks,<br>iv. business risks faced by all utilities in Canada, and ,<br>v. business risks unique to British Columbia<br>b) Changes in business risks in the last 5 years and explanation. | • Itemized listing of each risk with full explanation<br>  ○ FBCU, Business Risk Appendix<br>• Significance and impact of each risk to a utility<br>  ○ FBCU, Business Risk Appendix, Section 2.2<br>• Ranking of the business risks<br>  ○ FBCU, Business Risk Appendix, Section 2.2<br>• Business risks faced by all utilities in Canada<br>  ○ McShane Evidence, pp. 38-41<br>• Business risks unique to British Columbia<br>  ○ FBCU, Business Risk Appendix<br>• Changes in business risks in the last 5 years and explanation<br>  ○ McShane Evidence, pp. 48-56<br>  ○ FBCU, Business Risk Appendix |

| TABLE OF CONCORDANCE<br>FOR "OTHER FILING REQUIREMENTS" | | |
|---|---|---|
| 3. | Changes in:<br>a) the global financial markets,<br>b) provincial legislative and policy environment in BC, and<br>c) View on business operations since the last Commission Decision on the capital structure and return on equity for a benchmark utility (December 16, 2009 Decision on Terasen Utilities). | • Changes in global financial markets<br>  ○ Engen Evidence, pp.<*><br>  ○ McShane Evidence, pp. 17-33<br>• Changes in provincial legislative and policy environment in BC<br>  ○ FBCU, Business Risk Appendix, Section 9<br>• View on business operations since 2009 Decision<br>  ○ McShane Evidence, pp. 48-56<br>  ○ FBCU, Business Risk Appendix, Section 3<br>  ○ |
| 4. | Should the Commission return to a formulaic approach to setting a benchmark ROE, and if so, what should the formula be and for what period of time? | • Return to Formulaic Approach for ROE<br>  ○ FBCU Evidence, Section 2.6, pp.27-29<br>  ○ McShane Evidence, p. 33<br>  ○ Vander Weide Evidence, Section VII, pp. 47-49<br>  ○ Concentric Evidence, pp.11-13 |
| 5. | Should the GCOC Proceeding set a provision for the future review of a Benchmark ROE? | • FBCU Evidence, Section 2.6, pp. 27-29 |
| 6. | Capital Asset Pricing Model (CAPM) inputs – Risk-free rate forecasts for 2012, market equity risk premium forecasts or estimates, Beta estimates and flotation allowance and resulting CAPM results. | • McShane Evidence, pp. 66-70, 77-98 and 117-119<br>• Vander Weide Evidence, Section V, pp. 38-44 |
| 7. | Discounted Cash Flow Model (DCF) inputs – dividend yields, stage 1 growth rate estimates, stage 2 or terminal growth rate estimates, stage 2 or terminal period nominal GDP growth rate estimates, flotation allowance and resulting DCF result. | • McShane Evidence, pp. 109-113 and 117-119<br>• Vander Weide Evidence, Section V, pp. 25-31 |

| | | |
|---|---|---|
| **TABLE OF CONCORDANCE FOR "OTHER FILING REQUIREMENTS"** | | |
| 8. | Comparable Investments - Estimates of the ROE (on a market value and not a book value basis) available to investors in the public and private markets for investments of similar risk. | • McShane Evidence, pp. 106-108 and 112-113<br>• Vander Weide Evidence, pp. 13-47 |
| 9. | Market yields and credit spreads on high-grade utility and other corporate bonds. | • Engen Evidence, pp.29-36<br>• McShane Evidence, pp. 29-30 |
| 10. | Professional pension and investment managers; and economists' estimates of the prospective equity market returns available to investors buying equities at market prices. | • Appendix A, Item 11 |
| 11. | Proposed generic methodology or process for each utility to determine its return on equity in reference to the benchmark low-risk utility. | • FBCU Evidence, Section 4.1, p. 32<br>• McShane Evidence, pp. 128-131 |
| **Capital Structure Matters:** | | |
| 1. | Proposed capital structure/equity component for a benchmark low-risk utility in 2013 and, if applicable, beyond. | • FBCU Evidence, Section 2.5, pp. 24-27<br>• McShane Evidence, pp. 48-65<br>• Vander Weide Evidence, Section VIII, pp. 49-51<br>• Engen Evidence, pp.68-69 |
| 2. | Should the GCOC Proceeding set a provision for the future review of a benchmark low-risk utility capital structure? | • FBCU Evidence, Section 2.6, pp. 27-29 |
| 3. | Investment and business risks and any other risks faced by a utility's shareholders and customers. | • McShane Evidence, pp. 11-12, 39-41 and 72-75<br>• Vander Weide Evidence, Section III, pp. 10-12 and Section V, pp. 19-22 |
| 4. | Business risk ranking by industry sector – electricity, natural gas, alternative energy solutions providers, with accompanying reasons. | • McShane Evidence, pp. 43-48 |
| 5. | Change in business risks as a result of changes to business profile. | • FBCU, Business Risk Appendix, Section 3<br>• McShane Evidence, pp. 48-56 |
| 6. | Generic company-specific adjustments for effective income tax rates, size of utility, level of contributed assets, and company-specific or sector-specific factors. | • McShane Evidence, pp. 132-138 |

| TABLE OF CONCORDANCE<br>FOR "OTHER FILING REQUIREMENTS" | | |
|---|---|---|
| 7. | The credit environment and how it has changed and the extent to which it is already reflected in the market data above. | • Engen Evidence, pp.29-36<br>• McShane Evidence, pp. 17-33 |
| 8. | Proposed generic methodology or process for each utility to determine its equity ratio. | • FBCU Evidence, Section 4.1, p.32<br>• McShane Evidence, pp. 128-131 |
| **Designation of a Benchmark Low-risk Utility:** | | |
| 1. | Whether it is more appropriate that FortisBC Energy Inc. or some other utility be the benchmark utility for purpose of setting a benchmark low-risk utility return on equity and capital structure or whether a hypothetical benchmark low-risk utility be construed instead? | • FBCU Evidence, Section 2.2, pp. 17-21<br>• McShane Evidence, pp. 14-16 |
| **Deemed Capital Structure and Deemed Debt Issue Matters:** | | |
| 1. | What are the appropriate applicable circumstances for a utility to utilize a deemed capital structure with a deemed debt? | • FBCU Evidence, Section 2.7, p.29<br>• McShane Evidence, pp. 120-122 |
| 2. | What is an appropriate basis to calculate a deemed interest rate (long and short-term) for a utility without third-party debt or non-arms length debt? | • FBCU Evidence, Section 2.7, pp. 29-30<br>• McShane Evidence, p. 123 |
| 3. | Should the deemed long-term interest rate be based on a 10-year, 30-year, or other term-to-maturity Government of Canada bond and/or other term-to-maturity Canadian Corporate bond? | • FBCU Evidence, Section 2.7, p.30<br>• McShane Evidence, pp. 123-124 |
| 4. | What is the appropriate credit spread on the Government of Canada bond and/or the Canadian corporate bond for a benchmark low-risk utility? | • FBCU Evidence, Section 2.7, p.30<br>• McShane Evidence, pp. 124-125 |
| 5. | How does the deemed capital structure impact and relate to the credit spreads? | • McShane Evidence, p. 125 |
| 6. | What is an appropriate portion of short-term debt and long-term debt on the debt portion of the deemed capital structure? | • FBCU Evidence, Section 2.7, p.31<br>• McShane Evidence, pp. 125-127 |
| 7. | What is an appropriate basis to calculate the deemed interest rate for short-term debt? | • FBCU Evidence, Section 2.7, p.31<br>• McShane Evidence, pp. 127-128 |

| TABLE OF CONCORDANCE<br>FOR "OTHER FILING REQUIREMENTS" | | |
|---|---|---|
| 8. | Should a deemed short-term interest rate be based on 3-month Bankers' Acceptance rate and short-term 90-day loan? | • FBCU Evidence, Section 2.7, p.31<br>• McShane Evidence, pp. 127-128 |
| 9. | What methodology should be applied to calculate the deemed short-term interest rate? | • FBCU Evidence, Section 2.7, p.31<br>• McShane Evidence, pp. 127-128 |